SUMMARY OF LEGISLATIVE FRAMEWORK

1.0 PURPOSE

The purpose of this evidence is to provide a summary of the extensive legislative and regulatory framework as well as other government requirements that govern OPG and DNNP LP, and apply to OPG's prescribed facilities and the Darlington New Nuclear Program ("DNNP") facilities. The evidence also summarizes relevant best practices and guidelines to which OPG adheres.

This evidence is substantially the same as that filed in EB-2020-0290, with the following exceptions: the discussion of amendments to Ontario Regulation 53/05 ("O. Reg. 53/05") made subsequent to EB-2020-0290 in Section 3.0 (Attachment 1), including the addition of DNNP LP as a prescribed generator; a discussion of the *Building Canada Act* in Section 9.3; and the discussion of the repeal of the *Protecting a Sustainable Public Sector for Future Generations Act, 2019* in Section 10.2.

2.0 INTRODUCTION

OPG is subject to provincial and federal legislation and regulations, including the decisions of administrative tribunals or other regulatory bodies whose powers are derived from such legislation or regulations (e.g., the Ontario Labour Relations Board, the IESO, and the Canadian Nuclear Safety Commission ("CNSC")), and to Canada's international obligations under certain international treaties (e.g., regarding international boundary waters and nuclear safeguards). Compliance with the legislative framework can drive the need for certain programs and capital and non-capital expenditures, and impact OPG's operations.

3.0 ONTARIO ENERGY BOARD ACT

The *Ontario Energy Board Act, 1998* (the "Act"), when read in conjunction with O. Reg. 53/05, as made under the Act, as amended, establishes that OPG is a prescribed generator for the purposes of section 78.1 of the Act (Attachment 2). Effective January 1, 2026, DNNP LP is a prescribed generator for purposes of section 78.1 of the Act, subject to conditions set out in section 8 of O. Reg. 53/05. The combination of the Act and O. Reg. 53/05 provide that OPG and DNNP LP are entitled to receive just and reasonable payments, subject to specific rules in O. Reg. 53/05, with respect to the output from the prescribed generating facilities.

Since EB-2020-0290, O. Reg. 53/05 was amended on November 4, 2021, effective January 1, 2022, to include the DNNP as a regulated facility prescribed for the purposes of section 78.1 of the Act. Further details related to this variance account are found in Ex. H1-1-1.

In September 2022, the Government of Ontario asked OPG to operate Pickering Units 5-8 until the end of September 2026 (instead of December 2025), subject to approval by the CNSC. O. Reg 53/05 was further amended on December 8, 2022, effective January 1, 2023, to require the establishment of a Pickering B Extension Variance Account to track the additional revenues and costs associated with operating Pickering for the additional period. Further details related to this variance account are found in Ex. H1-1-1. O. Reg 53/05 was further amended, effective July 1, 2025, to record Pickering station-level and corporate costs that OPG is incurring in the 2024-2026 period for retaining the capacity and readiness to operate the Pickering Units 5-8 post-refurbishment.

O. Reg 53/05 was further amended, effective May 2, 2025, to replace references to "congestion management settlement credits" (“CMSCs”) with "CMSCs or make-whole payments, as the case may be" to align with new settlement processes introduced under the Market Renewal Program (“MRP”). MRP is referenced in Section 5.0, below, and discussed in greater detail in Ex. E1-2-1.

In December 2025, O. Reg. 53/05 was amended to: (i) provide a framework for recovery of interest amounts associated with the Pickering Refurbishment Program (“PRP”) and the DNNP prior to such assets being placed in service[1]; and (ii) establish a framework for the OEB to rate-regulate DNNP LP.[2]

[1] Further details on the amendments related to recovery of interest amounts before assets placed in service can be found in Ex. I1-1-3.
[2] Further details on the amendments establishing the framework for rate-regulating DNNP LP can be found in Ex. A1-4-4.

4.0 ELECTRICITY ACT

Part IV.1 of the *Electricity Act, 1998* applies directly to OPG. The provisions set out in this part of the *Electricity Act, 1998* establish the objects of OPG as well as certain obligations on OPG to provide reports to its shareholder.

5.0 ELECTRICITY MARKETS

Under authority granted to it by the *Electricity Act, 1998*, the IESO administers and ensures compliance with the Market Rules for the Ontario Electricity Market (the "Market Rules"). All of OPG's prescribed generating facilities are registered in the IESO-controlled markets and are therefore required to comply with all applicable Market Rules.

On May 1, 2025, the IESO implemented broad changes to Ontario's electricity market, known as the MRP. MRP is discussed in greater detail in Ex. E1-2-1.

6.0 OEB LICENCE

OPG holds an Electricity Generation Licence (EG-2023-0231) from the OEB, which is valid until October 2, 2043 (the "Licence"). The Licence can be found in Attachment 3.

The Licence applies to all generating stations that are owned and/or operated by OPG, including the prescribed facilities. The Licence obligates OPG to comply with all applicable provisions of the Act, the *Electricity Act, 1998*, all regulations under these acts, and all applicable Market Rules. The Licence further obligates OPG to enter into agreements for the supply of energy or ancillary services where the IESO deems necessary for the purpose of maintaining the reliability and security of the IESO-controlled electricity grid. On April 30, 2025, the OEB ordered the amendment of the Licence to include changes to the Must-Offer Condition required as a result of MRP. On August 28, 2025, the OEB further ordered the Licence be amended to include a limited scope exemption from the ring-fencing provisions to allow OPG to share non-public information about planned outages at Sir Adam Beck II Generating Station with NV LP (also known as Atura Power), which is constructing a hydrogen production facility next to the station.

DNNP LP will apply to the OEB for an electricity generation licence in respect of the operation of the DNNP facilities prior to the first unit entering commercial operation. As OPG will be the owner of the DNNP facilities, OPG will request an amendment to its generation licence to reflect ownership of the DNNP facilities in a parallel application.

7.0 REGULATED HYDROELECTRIC GENERATING FACILITIES

OPG's prescribed hydroelectric facilities are subject to international treaties between Canada and the United States; federal and provincial regulatory and legislative requirements; and common law as it pertains to riparian interests, waterways, and real property. The key regulatory obligations and constraints applicable to the prescribed hydroelectric facilities are highlighted below.

7.1 Water Rights and Usage

Relevant legislation and agreements include:

- *Public Lands Act* (Ontario);
- *Lakes and Rivers Improvement Act* (Ontario);
- *Niagara Parks Act* (Ontario);
- *Boundary Waters Treaty of 1909 between Great Britain and the United States* (sanctioned by the Parliament of Canada);
- *Niagara Diversion Treaty of 1950* between Canada and the United States;
- *Niagara Development Act, 1951* (Ontario);
- Agreement between OPG and the Niagara Parks Commission, February 2005;
- *International Rapids Power Development Agreement Act, 1952*, between Canada and Ontario;
- *St. Lawrence Development Act, 1952 (No. 2)* (Ontario);
- *Dominion Water Power Act* and *Dominion Water Power Regulations* (Canada);
- *Ottawa River Water Powers Act, 1943* (Ontario and Quebec);
- Agreement Respecting Ottawa River Basin Regulation, 1983 (Canada, Ontario, Quebec) pertaining to management and regulation of the waters within the Ottawa River basin;

- Agreement Regarding the Review of the Rent for the Water Powers of the Ottawa River, executed November 2020 (Ontario, Quebec, Hydro Quebec and OPG)
- *Lake of the Woods Control Board Act* (Canada, 1921, and Ontario, 1922) and amendments (Ontario, 1958);
- *Tripartite Agreement (Canada, Ontario, and Manitoba),1922*, pertaining to control of upper waters of the Winnipeg River;
- *Lac Seul Conservation Act, 1928* (Canada);
- *Manitoba-Ontario Lake St. Joseph Diversion Agreement Authorization Act, 1958* (Manitoba);
- *Electricity Act, 1998*, section 92.1, which addresses the gross revenue charge;
- Water Power Leases and Water Power Lease Agreements, Crown Leases and Licences of Occupation with Ontario Ministry of Natural Resources;
- Licences with Parks Canada for facilities on the Trent River and Rideau Canal;
- Lease agreement with St. Lawrence Seaway Management Corporation for diversion of water from the Welland Ship Canal for utilization at DeCew Falls; and
- Agreements between OPG and other utilities/generators (New York Power Authority, Manitoba Hydro, Hydro-Québec) related to operational requirements/guidelines, joint works, water sharing, water diversions, and compensation settlements.

7.2 Dam Safety

OPG’s Safe Operations Policy and the associated Dam Safety Program Management document require that all OPG dams be designed, constructed, operated, and maintained in accordance with all regulations. In the absence of a specific regulation, the Canadian Dam Association (“CDA”) Dam Safety Guidelines (2013), the CDA Guidelines for Public Safety Around Dams (2011), or other appropriate industry standards shall apply. These guidelines and OPG’s internal standards provide guidance on dam safety covering inspections, testing of flow control equipment, emergency preparedness planning, periodic reviews of safety, and other aspects considered critical for ensuring the safety of the prescribed hydroelectric facilities and their operations.

In Ontario, provincial legislative authority over dams is exercised through the *Lakes and Rivers Improvement Act* and the supporting Regulation 454/96. In August 2011, the Province of Ontario enhanced the direction to dam owners with the provision of new Technical Guidelines for Approval under the *Lakes and Rivers Improvement Act*.

In Quebec, provincial legislative authority over dams is exercised through the *Quebec Dam Safety Act* and the supporting Quebec Dam Safety Regulation. This covers OPG facilities on the Ottawa River.

The Government of Canada exercises authority over dams through the *Canadian Navigable Waters Act* and the *Canada Shipping Act, 2001*, including associated regulations. These acts apply to OPG in relation to the construction of new dams, alterations to existing dams, and the administration of “approved works”, such as safety booms and exclusion zones associated with OPG’s measures to manage public safety. The Government of Canada has jurisdiction over all boundary waters as well as waters associated with canals. In addition to operating the Sir Adam Beck facilities on the Niagara River and the R.H. Saunders facility on the St. Lawrence River, OPG also operates a number of structures on the Trent Severn Waterway and the Rideau Canal which come under federal jurisdiction. In the case of the OPG facilities located on the Trent Severn Waterway and Rideau Canal, the guidelines that OPG is required to follow are administered by Parks Canada’s Dam Safety Directive (2009).

Relevant dam safety guidelines and legislation include:

- CDA Dam Safety and Public Safety Around Dams Guidelines;
- *Lakes and Rivers Improvement Act* (Ontario);
- Province of Ontario Dam Safety Technical Guidelines;
- *Canadian Navigable Waters Act* (Canada);
- *Canada Shipping Act, 2001* and the Vessel Operation Restriction Regulations;
- International Joint Commission regulation of the Niagara and St. Lawrence Rivers, pursuant to the *Boundary Waters Treaty of 1909;*
- *Dam Safety Act* (Quebec) and Dam Safety Regulation;
- *Civil Protection Act* (Quebec); and
- Directive for Dam Safety Program of Parks Canada Dams and Water-Retaining Structures.

8.0 NUCLEAR GENERATING FACILITIES

8.1 Nuclear Operations and Materials

OPG's nuclear operations are subject to the jurisdiction of the CNSC, an independent federal government agency that derives its powers from, and is responsible for administering, ensuring compliance with and enforcing the *Nuclear Safety and Control Act*, which is described below. Several of the key regulatory regimes that are uniquely applicable to OPG's nuclear facilities are discussed below.

The *Nuclear Safety and Control Act* is intended to limit the risks to national security, the health and safety of persons and the environment that are associated with the development, production and use of nuclear energy, as well as to limit risks associated with the production, possession and use of nuclear substances, certain equipment and certain related information. This act also implements measures to which Canada has agreed respecting international control of the development, production and use of nuclear energy, including the non-proliferation of nuclear weapons and nuclear explosive devices. In addition, this act establishes the CNSC and delineates its powers.

The CNSC's regulatory control extends to regulating all aspects of site preparation, construction, operation (including maintenance, and refurbishment for life extension), and decommissioning of nuclear facilities.

The CNSC exercises its mandate in respect of OPG's nuclear operations by means of the issuance of operating licences and amendments, as well as through continuous monitoring and inspections to ensure compliance with operating licences, along with relevant legislative standards, applicable regulations, and CNSC regulatory documents (all of which form part of OPG's licensing basis). The regulator issues requests for action and information on a routine basis. Operating licences impose numerous conditions and constraints on OPG, including obligations to comply with relevant legislation, applicable regulations, and regulatory documents issued by the CNSC and various external standards and codes (e.g., National Building Code, National Fire Code, Canadian Standards Association Standards). The CNSC has issued a number of regulatory documents for nuclear power plants, including for example, ones relating to maintenance programs, reliability programs, aging management, safety analysis, and emergency preparedness.

For refurbishment of nuclear power plants for life extension, the regulatory process and CNSC expectations have been documented in Regulatory Document *2.3.3 Periodic Safety Reviews*, (which superseded RD-360, Life Extension of Nuclear Power Plants) (see Ex. D2-3-1, Attachment 1 and Attachment 4). This document outlines expectations for, and CNSC acceptance of, Periodic Safety Reviews against modern codes and standards, including requiring a safety factor review, a global assessment report, and the ensuing integrated implementation plan for the corrective actions and safety improvements. Regulatory control by the CNSC is exercised through amended operating licences by including licence conditions that have to be met.

The CNSC also issues guidance documents that provide direction to licensees and applicants on how to meet the requirements set out in applicable regulations, the CNSC's regulatory documents, and licences. It is OPG's practice to incorporate the directions from these guidance documents into the design and operating documents for its nuclear generating stations.

OPG must maintain compliance in order to ensure that the nuclear facility is fit for service and continued operation.

OPG currently holds two Power Reactor Operating Licences from the CNSC, which allow for the operation of Pickering and Darlington, as well as separate licences that authorize the operation of nuclear waste management facilities. OPG also maintains regulated certificates for radioactive material transportation packages, and licences for the possession, transport, and import/export of certain radioactive materials. OPG also holds a licence to construct a new nuclear power plant at the Darlington site. OPG regularly seeks licence amendments, as well as new licences, from the CNSC on an as-needed basis in order to ensure ongoing regulatory compliance.

In addition to the resources and costs associated with complying with the conditions in these licences, the application process for each licence, including significant amendments or renewal, requires extensive preparation and the conduct of public hearings involving CNSC staff, intervening stakeholders, and Indigenous rightsholders. OPG is required to pay a licence fee to the CNSC each year, under the CNSC's Cost Recovery Fees Regulations, which in effect covers the CNSC's costs of staff and resources to administer the licence including compliance activities and inspections. Further, as set out above, OPG's nuclear facilities are required to operate in accordance with numerous regulations under this act, including:

- General Nuclear Safety and Control Regulations;
- Class 1 Nuclear Facilities Regulations;
- Packaging and Transport of Nuclear Substances Regulations, 2015;
- Nuclear Security Regulations;
- Radiation Protection Regulations;
- Nuclear Substances and Radiation Devices Regulations;
- Class II Nuclear Facilities and Prescribed Substances Regulations;
- Nuclear Non-proliferation Import and Export Control Regulations; and
- CNSC Cost Recovery Fees Regulations.

A person or organization may only possess or dispose of nuclear substances, or construct, operate and decommission nuclear facilities in accordance with the terms of a licence issued by the CNSC. Licences incorporate the applicable requirements set out in the regulations.

It is a fundamental principle of nuclear regulation that the licensee, in this case OPG, bears responsibility for the safe operation of nuclear facilities. The CNSC sets safety objectives in areas such as radiation protection, physical site security, and the transport of radioactive materials. OPG is required to design, implement, monitor, and continually improve upon its extensive programs in each of these critical areas. The CNSC audits OPG's performance against these objectives, continually monitors OPG's safety performance, and reports annually to Parliament with an assessment of licensee performance in all areas of nuclear safety. The delivery and continual improvement of these programs represent a significant cost driver for OPG in respect of the nuclear facilities.

8.2 Civil Liability

OPG is subject to the *Nuclear Liability and Compensation Act* (Canada), which governs civil liability for damages in Canada related to nuclear incidents. The legislation requires OPG (and all other operators of nuclear generating stations in Canada) to maintain specified amounts of nuclear liability insurance purchased from a federal government approved insurer or other equivalent forms of financial security approved by the federal government.

8.3 Nuclear Waste Management

The *Nuclear Safety and Control Act* provides the CNSC with authority over nuclear waste from a health, safety and environmental protection perspective. The CNSC licences all of OPG's waste management facilities. OPG also has obligations under the *Nuclear Fuel Waste Act* (Canada) which addresses the long-term handling and disposal of used nuclear fuel.

Coincident with the formation of OPG on April 1, 1999, OPG and the Province of Ontario entered into the Ontario Nuclear Funds Agreement ("ONFA"). The ONFA is an agreement that generally establishes the responsibilities for funding OPG's nuclear waste management and decommissioning liabilities, which were inherited from Ontario Hydro. The ONFA is discussed in greater detail in Ex. C2-1-1.

8.4 Security Personnel

Beyond the nuclear-specific federal requirements described above, two pieces of provincial legislation apply in respect of the security personnel associated with OPG's nuclear generating facilities. These are the *Police Services Act* (Ontario) and the *Security for Electricity Generating Stations and Nuclear Generating Stations Act* (Ontario).

9.0 ENVIRONMENTAL

9.1 General

The environmental legislation and best practice standards that impact OPG's nuclear and/or prescribed hydroelectric facilities include:

- *Fisheries Act* (Canada);
- *Conservation Authorities Act* (Ontario);

- *Clean Water Act, 2006* (Ontario);
- *Environmental Assessment Act* (Ontario);
- *Environmental Protection Act* (Ontario);
- *Great Lakes Protection Act, 2015* (Ontario);
- *Ontario Water Resources Act*;
- *Endangered Species Act, 2007* (Ontario);
- *Migratory Birds Convention Act, 1994* (Canada);
- *Species at Risk Act* (Canada);
- *Transportation of Dangerous Goods Act, 1992* (Canada); and
- ISO 14001 Environmental Management System standard, to which OPG has corporate registration.

9.2 The Impact Assessment Act

In *Reference re Impact Assessment Act*, 2023 SCC 23, the Supreme Court of Canada held that portions of the federal *Impact Assessment Act* ("IAA") was unconstitutional because it exceeded the powers allocated to Parliament under section 91 of the *Constitution Act, 1867*. In response, Parliament passed amendments to the IAA that came into force June 20, 2024, focusing impact assessments on areas of federal jurisdiction.

Under the *IAA*, the Impact Assessment Agency of Canada leads the reviews of certain major projects and works in collaboration with CNSC to review such projects that are subject to regulation under the *Nuclear Safety and Control Act*.

9.3 The Building Canada Act

On June 26, 2025, the *Building Canada Act* came into force. The *Building Canada Act* implements a streamlined process for approving projects that are designated as being in the national interest. The Major Projects Office was established to advance these projects. The Major Projects Office's interplay with the DNNP is discussed in Ex. D2-04-01.

10.0 OTHER

10.1 General

OPG's prescribed facilities are also subject to broad range of generally applicable legislative and regulatory requirements in the following areas:

- Technical standards and safety including corresponding regulations and codes, particularly in respect of fuel storage tanks;
- Heritage;
- Dangerous goods transportation;
- Construction and liens;
- Occupational health and safety;
- Employment standards;
- Labour relations;
- Public sector executive compensation;
- Freedom of information; and
- Relevant municipal by-laws.

10.2 The repeal of the *Protecting a Sustainable Public Sector for Future Generations Act, 2019*

The *Protecting a Sustainable Public Sector for Future Generations Act, 2019* ("Bill 124") set limits on compensation increases for unionized and non-unionized employees in the Ontario public sector. Since EB-2020-0290, the Ontario Superior Court, in *Ontario English Catholic Teachers Assoc. v. His Majesty*, 2022 ONSC 6658, held that Bill 124 was unconstitutional. Following that decision, Bill 124 was then repealed on February 23, 2024. The effect of the repeal of Bill 124 is discussed in Ex. F4-3-1.

LIST OF ATTACHMENTS

Attachment 1:	Ontario Regulation 53/05
Attachment 2:	Section 78.1 of the OEB Act
Attachment 3:	OPG Electricity Generation Licence
Attachment 4:	RD-360, Life Extension of Nuclear Power Plants

Ontario Energy Board Act, 1998

ONTARIO REGULATION 53/05
PAYMENTS UNDER SECTION 78.1 OF THE ACT

Consolidation Period: From July 1, 2025 to the e-Laws currency date.

Last amendment: 142/25.

Legislative History: 269/05, 23/07, 27/08, 312/13, 353/15, 57/17, 622/20, 739/21, 557/22, 46/25, 142/25.

This is the English version of a bilingual regulation.

Definitions

0.1 (1) In this Regulation,

"approved reference plan" means a reference plan, as defined in the Ontario Nuclear Funds Agreement, that has been approved by Her Majesty the Queen in right of Ontario in accordance with that agreement; ("plan de renvoi approuvé")

"base payment amount" means the payment amount approved by the Board in respect of output from the hydroelectric facilities or the nuclear facilities, as the case may be, excluding any fixed or variable payment amount rider; ("montant du paiement de base")

"calculation period" means each period for which the Board determines the approved revenue requirements under subparagraph 12 ii of subsection 6 (2) together with the year immediately prior to that period; ("période de calcul")

"Darlington Refurbishment Project" means the work undertaken by Ontario Power Generation Inc. in respect of the refurbishment, in whole or in part, of some or all of the generating units of the Darlington Nuclear Generating Station; ("projet de remise en état de la centrale de Darlington")

"deferral period" means the period beginning on January 1, 2017, and ending when the Darlington Refurbishment Project ends; ("période de report")

"hydroelectric facilities" means the hydroelectric generation facilities prescribed in paragraphs 1, 2 and 6 of section 2; ("installations hydroélectriques")

"nuclear decommissioning liability" means the liability of Ontario Power Generation Inc. for decommissioning its nuclear generation facilities and the management of its nuclear waste and used fuel; ("obligation en matière de déclassement nucléaire")

"nuclear facilities" means the nuclear generation facilities prescribed in paragraphs 3, 4, 5 and 7 of section 2; ("installations nucléaires")

"Ontario Nuclear Funds Agreement" means the agreement entered into as of April 1, 1999 by Her Majesty the Queen in right of Ontario, Ontario Power Generation Inc. and certain subsidiaries of Ontario Power Generation Inc., including any amendments to the agreement; ("Ontario Nuclear Funds Agreement")

"OPG weighted average payment amount" for a year means the total production-weighted average payment amount that is used in the determination of the payments made under section 78.1 of the Act with respect to the generation facilities prescribed in section 2 of this Regulation, calculated according to the formula:

$$(((NPA + NPR) \times NPF) + (HPA + HPR) \times HPF) / (NPF + HPF)$$

where,

NPA is the Board-approved payment amount for the year in respect of the nuclear facilities,

NPR is the Board-approved payment amount rider for the year in respect of the recovery of balances recorded in the deferral accounts and variance accounts established for the nuclear facilities, excluding the deferral account established under subsection 5.5 (1),

NPF is the Board-approved production forecast for the nuclear facilities for the year, HPA is the Board-approved payment amount for the year, or the expected payment amount resulting from a Board-approved rate-setting formula, as applicable, in respect of the hydroelectric facilities,

HPR is the Board-approved payment amount rider for the year in respect of the recovery of balances recorded in the deferral accounts and variance accounts established for the hydroelectric facilities, and

HPF is the Board-approved production forecast for the hydroelectric facilities for the year; ("paiement moyen pondéré effectué à OPG")

"Pickering B extension activities" means any activities in furtherance of the operation of the Pickering B Nuclear Generating Station during the Pickering B extension period, whether or not the activities occurred during that period; ("activités de prolongation de l'exploitation de Pickering B")

"Pickering B extension period" means the period beginning on January 1, 2026 and ending no later than September 30, 2026; ("période de prolongation de l'exploitation de Pickering B")

"Pickering closure" means the closure or decommissioning of the Pickering A Nuclear Generating Station or Pickering B Nuclear Generating Station, or the retirement of a generating unit at the Pickering A Nuclear Generating Station or Pickering B Nuclear Generating Station from electricity generation; ("fermeture de Pickering")

"Pickering closure activities" means any activities in furtherance of a Pickering closure; ("activités de fermeture de Pickering")

"Pickering B preservation activities" means any activities undertaken by Ontario Power Generation Inc. on or after January 1, 2024 to preserve its ability to operate the Pickering B Nuclear Generating Station following the Pickering B Refurbishment Project, regardless of whether the Pickering B Refurbishment Project proceeds; ("activités de préservation de l'exploitation de Pickering B")

"Pickering B Refurbishment Project" means the work undertaken by Ontario Power Generation Inc. in respect of the refurbishment, in whole or in part, of some or all of the generating units of the Pickering B Nuclear Generating Station; ("projet de remise en état de la centrale de Pickering B")

"small modular reactor" means a nuclear generation facility with an operating capacity of 500 megawatts or less. ("petit réacteur modulaire") O. Reg. 23/07, s. 1; O. Reg. 353/15, s. 1; O. Reg. 57/17, s. 1; O. Reg. 622/20, s. 1; O. Reg. 739/21, s. 1; O. Reg. 557/22, s. 1; O. Reg. 142/25, s. 1.

(2) For the purposes of this Regulation, the output of a generation facility shall be measured at the facility's delivery points, as determined in accordance with the market rules. O. Reg. 312/13. s. 1.

Prescribed generator

1. Ontario Power Generation Inc. is prescribed as a generator for the purposes of section 78.1 of the Act. O. Reg. 53/05, s. 1.

Prescribed generation facilities

2. The following generation facilities of Ontario Power Generation Inc. are prescribed for the purposes of section 78.1 of the Act:

1. The following hydroelectric generating stations located in The Regional Municipality of Niagara:
   i. Sir Adam Beck I.
   ii. Sir Adam Beck II.
   iii. Sir Adam Beck Pump Generating Station.
   iv. De Cew Falls I.
   v. De Cew Falls II.
2. The R. H. Saunders hydroelectric generating station on the St. Lawrence River.
3. Pickering A Nuclear Generating Station.
4. Pickering B Nuclear Generating Station.
5. Darlington Nuclear Generating Station.
6. As of July 1, 2014, the generation facilities of Ontario Power Generation Inc. that are set out in Schedule 1.
7. Any small modular reactors on the lands owned by Ontario Power Generation Inc. in the Municipality of Clarington, Regional Municipality of Durham that are described in Schedule 2. O. Reg. 53/05, s. 2; O. Reg. 23/07, s. 2; O. Reg. 312/13, s. 2; O. Reg. 739/21, s. 2.

Prescribed date for s. 78.1 (2) of the Act

3. April 1, 2008 is prescribed for the purposes of subsection 78.1 (2) of the Act. O. Reg. 53/05, s. 3.

4. REVOKED: O. Reg. 312/13, s. 3.

Deferral and variance accounts

5. (1) Ontario Power Generation Inc. shall establish a variance account in connection with section 78.1 of the Act that records capital and non-capital costs incurred and revenues earned or foregone on or after April 1, 2005 due to deviations from the forecasts as set out in the document titled "Forecast Information (as of Q3/2004) for Facilities Prescribed under Ontario Regulation 53/05" posted and available on the Ontario Energy Board website, that are associated with,

(a) differences in hydroelectric electricity production due to differences between forecast and actual water conditions;

(b) unforeseen changes to nuclear regulatory requirements or unforeseen technological changes which directly affect the nuclear generation facilities, excluding revenue requirement impacts described in subsections 5.1 (1) and 5.2 (1);

(c) changes to revenues for ancillary services from the generation facilities prescribed under section 2;

(d) acts of God, including severe weather events; and

(e) transmission outages and transmission restrictions that are not otherwise compensated for through congestion management settlement credits, or make-whole payments, as the case may be, under the market rules. O. Reg. 23/07, s. 3; O. Reg. 46/25, s. 1.

(2) The calculation of revenues earned or foregone due to changes in electricity production associated with clauses (1) (a), (b), (d) and (e) shall be based on the following prices:

1. $33.00 per megawatt hour from hydroelectric generation facilities prescribed in paragraphs 1 and 2 of section 2.
2. $49.50 per megawatt hour from nuclear generation facilities prescribed in paragraphs 3, 4 and 5 of section 2. O. Reg. 23/07, s. 3.

(3) Ontario Power Generation Inc. shall record simple interest on the monthly opening balance of the account at an annual rate of 6 per cent applied to the monthly opening balance in the account, compounded annually. O. Reg. 23/07, s. 3.

(4) Ontario Power Generation Inc. shall establish a deferral account in connection with section 78.1 of the Act that records non-capital costs incurred on or after January 1, 2005 that are associated with the planned return to service of all generating units at the Pickering A Nuclear Generating Station, including those generating units which the board of directors of Ontario Power Generation Inc. has determined should be placed in safe storage. O. Reg. 23/07, s. 3; O. Reg. 557/22, s. 2.

(5) For the purposes of subsection (4), the non-capital costs include, but are not restricted to,

(a) construction costs, assessment costs, pre-engineering costs, project completion costs and demobilization costs; and

(b) interest costs, recorded as simple interest on the monthly opening balance of the account at an annual rate of 6 per cent applied to the monthly opening balance in the account, compounded annually. O. Reg. 23/07, s. 3.

5.1 REVOKED: O. Reg. 312/13, s. 3.

Nuclear liability deferral account

5.2 (1) Ontario Power Generation Inc. shall establish a deferral account in connection with section 78.1 of the Act that records, on and after the effective date of the Board's first order under 78.1 of the Act, the revenue requirement impact of changes in its total nuclear decommissioning liability between,

(a) the liability arising from the approved reference plan incorporated into the Board's most recent order under section 78.1 of the Act; and

(b) the liability arising from the current approved reference plan. O. Reg. 23/07, s. 3.

(2) Ontario Power Generation Inc. shall record interest on the balance of the account as the Board may direct. O. Reg. 23/07, s. 3.

5.3 REVOKED: O. Reg. 312/13, s. 3.

Nuclear development variance account

5.4 (1) Ontario Power Generation Inc. shall establish a variance account in connection with section 78.1 of the Act that records, on and after the effective date of the Board's first order under section 78.1 of the Act, differences between,

(a) the revenue requirement impacts arising from the actual non-capital and capital costs incurred and firm financial commitments made for proposed new nuclear generation facilities, including but not limited to the costs of,

(i) planning and preparation for the new facilities,

(ii) technology identification for the new facilities, and

(iii) design, development and construction of the new facilities; and

(b) the amount of the revenue requirement impacts arising from non-capital and capital costs and firm financial commitments that were included in payments made under section 78.1 of the Act. O. Reg. 739/21, s. 3.

(2) Ontario Power Generation Inc. shall record interest on the balance of the account as the Board may direct. O. Reg. 27/08, s. 1.

Darlington refurbishment rate smoothing deferral account

5.5 (1) Ontario Power Generation Inc. shall establish a deferral account in connection with section 78.1 of the Act that records, on and after the commencement of the deferral period, the difference between,

(a) the revenue requirement amount approved by the Board that, but for subparagraph 12 i of subsection 6 (2) of this Regulation, would have been used in connection with determining the payments to be made under section 78.1 of the Act each year during the deferral period in respect of the nuclear facilities; and

(b) the portion of the revenue requirement amount referred to in clause (a) that is used in connection with determining the payments made under section 78.1 of the Act, after determining, under subparagraph 12 i of subsection 6 (2) of this Regulation, the amount of the revenue requirement to be deferred for that year in respect of the nuclear facilities. O. Reg. 353/15, s. 2.

(2) Ontario Power Generation Inc. shall record interest on the balance of the account at a long-term debt rate reflecting Ontario Power Generation Inc.'s cost of long-term borrowing that is determined or approved by the Board from time to time, compounded annually. O. Reg. 353/15, s. 2.

Pickering closure costs deferral account

5.6 (1) Ontario Power Generation Inc. shall establish a deferral account in connection with section 78.1 of the Act that records any employment-related costs and non-capital costs related to third party service providers incurred by Ontario Power Generation Inc. that arise from any Pickering closure activities, including,

(a) costs related to employee termination, layoff, reassignment or retraining; and

(b) costs related to the hiring of employees or the engagement of third party service providers to perform Pickering closure activities, and their remuneration. O. Reg. 622/20, s. 2.

(2) Subsection (1) applies whether the costs are incurred before or after a Pickering closure, but does not apply to,

(a) costs that are eligible for recovery by Ontario Power Generation Inc. under the Ontario Nuclear Funds Agreement; or

(b) for greater certainty, costs that have already been included in an order made by the Board under section 78.1 of the Act. O. Reg. 622/20, s. 2.

(3) Ontario Power Generation Inc. shall record Pickering closure costs in the deferral account as they are reflected in the audited financial statements approved by the board of directors of Ontario Power Generation Inc., and shall record interest on the balance of the account as the Board may direct. O. Reg. 622/20, s. 2.

Pickering B variance account

5.7 (1) Ontario Power Generation Inc. shall establish a variance account in connection with section 78.1 of the Act that records the difference between,

(a) revenues generated during the Pickering B extension period that are earned from the output of the Pickering B Nuclear Generating Station, calculated on the basis of the base payment amount for the nuclear facilities that applies on January 1, 2026; and

(b) the sum of,

(i) any foregone revenues related to foregone output from the Pickering B Nuclear Generating Station arising from any Pickering B extension activities,

(ii) the revenue requirement impacts arising from the actual non-capital and capital costs incurred in relation to any Pickering B extension activities, and

(iii) the revenue requirement impacts arising from any actual non-capital and capital costs, including but not limited to costs payable for staffing, training, corporate support or administrative functions, incurred in relation to any Pickering B preservation activities before the effective date of the Board's first order under section 78.1 of the Act setting base payment amounts for the nuclear facilities that becomes effective on or after January 1, 2027. O. Reg. 557/22, s. 3; O. Reg. 142/25, s. 2.

(2) The variance account shall,

(a) take into account any related income tax effects; and

(b) not include any amounts included in,

(i) the Board's order under section 78.1 of the Act dated January 27, 2022 setting payment amounts for the nuclear facilities, or

(ii) a deferral account established under section 5.2 or 5.6. O. Reg. 557/22, s. 3.

(3) Ontario Power Generation Inc. shall record interest on the balance of the account as the Board may direct. O. Reg. 557/22, s. 3.

Rules governing determination of payment amounts by Board

6. (1) Subject to subsection (2), the Board may establish the form, methodology, assumptions and calculations used in making an order that determines payment amounts for the purpose of section 78.1 of the Act. O. Reg. 53/05, s. 6 (1).

(2) The following rules apply to the making of an order by the Board that determines payment amounts for the purpose of section 78.1 of the Act:

1. The Board shall ensure that Ontario Power Generation Inc. recovers the balance recorded in the variance account established under subsection 5 (1) over a period not to exceed three years, to the extent that the Board is satisfied that,

   i. the revenues recorded in the account were earned or foregone and the costs were prudently incurred, and

   ii. the revenues and costs are accurately recorded in the account.

2. In setting payment amounts for the assets prescribed under section 2, the Board shall not adopt any methodologies, assumptions or calculations that are based upon the contracting for all or any portion of the output of those assets.

3. The Board shall ensure that Ontario Power Generation Inc. recovers the balance recorded in the deferral account established under subsection 5 (4). The Board shall authorize recovery of the balance on a straight line basis over a period not to exceed 15 years.

4. The Board shall ensure that Ontario Power Generation Inc. recovers capital and non-capital costs and firm financial commitments incurred in respect of the Darlington Refurbishment Project or incurred to increase the output of, refurbish or add operating capacity to a generation facility referred to in section 2, including, but not limited to, assessment costs and pre-engineering costs and commitments,

   i. if the costs and financial commitments were within the project budgets approved for that purpose by the board of directors of Ontario Power Generation Inc. before the making of the Board's first order under section 78.1 of the Act in respect of Ontario Power Generation Inc., or

   ii. if the costs and financial commitments were not approved by the board of directors of Ontario Power Generation Inc. before the making of the Board's first order under section 78.1 of the Act in respect of Ontario Power Generation Inc., if the Board is satisfied that the costs were prudently incurred and that the financial commitments were prudently made.

4.1 The Board shall ensure that Ontario Power Generation Inc. recovers the non-capital and capital costs incurred and firm financial commitments made for proposed new nuclear generation facilities, including but not limited to the costs described in subclauses 5.4 (1) (a) (i) to (iii), to the extent the Board is satisfied that,

   i. the costs were prudently incurred, and

   ii. the financial commitments were prudently made.

5. In making its first order under section 78.1 of the Act in respect of Ontario Power Generation Inc., the Board shall accept the amounts for the following matters as set out in Ontario Power Generation Inc.'s most recently audited financial statements that were approved by the board of directors of Ontario Power Generation Inc. before the effective date of that order:

   i. Ontario Power Generation Inc.'s assets and liabilities, other than the variance account referred to in subsection 5 (1), which shall be determined in accordance with paragraph 1.

ii. Ontario Power Generation Inc.'s revenues earned with respect to any lease of the Bruce Nuclear Generating Stations.

iii. Ontario Power Generation Inc.'s costs with respect to the Bruce Nuclear Generating Stations.

6. Without limiting the generality of paragraph 5, that paragraph applies to values relating to,

   i. capital cost allowances,

   ii. the revenue requirement impact of accounting and tax policy decisions, and

   iii. capital and non-capital costs and firm financial commitments to increase the output of, refurbish or add operating capacity to a generation facility referred to in section 2.

7. The Board shall ensure that the balance recorded in the deferral account established under subsection 5.2 (1) is recovered on a straight line basis over a period not to exceed three years, to the extent that the Board is satisfied that revenue requirement impacts are accurately recorded in the account, based on the following items, as reflected in the audited financial statements approved by the board of directors of Ontario Power Generation Inc.,

   i. return on rate base,

   ii. depreciation expense,

   iii. income and capital taxes, and

   iv. fuel expense.

7.1 The Board shall ensure the balance recorded in the variance account established under subsection 5.4 (1) is recovered on a straight line basis over a period not to exceed three years, to the extent the Board is satisfied that,

   i. the costs were prudently incurred, and

   ii. the financial commitments were prudently made.

7.2 The Board shall ensure that the balance recorded in the deferral account established under subsection 5.6 (1) and related income tax effects are recovered on a straight line basis over a period not to exceed 10 years beginning on the day the last generating unit of the Pickering A Nuclear Generating Station and Pickering B Nuclear Generating Station permanently stops generating electricity, to the extent that the Board is satisfied that the costs were prudently incurred and are accurately recorded in the account.

8. The Board shall ensure that Ontario Power Generation Inc. recovers the revenue requirement impact of its nuclear decommissioning liability arising from the current approved reference plan.

9. The Board shall ensure that Ontario Power Generation Inc. recovers all the costs it incurs with respect to the Bruce Nuclear Generating Stations.

10. If Ontario Power Generation Inc.'s revenues earned with respect to any lease of the Bruce Nuclear Generating Stations exceed the costs Ontario Power Generation Inc. incurs with respect to those Stations, the excess shall be applied to reduce the amount of the payments required under subsection 78.1 (1) of the Act with respect to output from the nuclear facilities.

11. In making its first order under section 78.1 of the Act in respect of Ontario Power Generation Inc. that is effective on or after July 1, 2014, the following rules apply:

   i. The order shall provide for the payment of amounts with respect to output that is generated at a generation facility referred to in paragraph 6 of section 2 during the period from July 1, 2014 to the day before the effective date of the order.

   ii. The Board shall accept the values for the assets and liabilities of the generation facilities referred to in paragraph 6 of section 2 as set out in Ontario Power Generation Inc.'s most recently audited financial statements that were approved by the board of directors before the making of that order. This includes values relating to the income tax effects of timing differences and the revenue requirement impact of accounting and tax policy decisions reflected in those financial statements.

12. For the purposes of section 78.1 of the Act, in setting payment amounts for the nuclear facilities during the deferral period,

   i. the Board shall determine the portion of the Board-approved revenue requirement for the nuclear facilities for each year that is to be recorded in the deferral account established under subsection 5.5 (1), with a view to making more stable the year-over-year changes in the OPG weighted average payment amount over each calculation period,

ii. the Board shall determine the approved revenue requirements referred to in subsection 5.5 (1) and the amount of the approved revenue requirements to be deferred under subparagraph i on a five-year basis for the first 10 years of the deferral period and, thereafter, on such periodic basis as the Board determines,

iii. for greater certainty, the Board's determination of Ontario Power Generation Inc.'s approved revenue requirement for the nuclear facilities shall not be restricted by the yearly changes in payment amounts in subparagraph i,

iv. the Board shall ensure that Ontario Power Generation Inc. recovers the balance recorded in the deferral account established under subsection 5.5 (1), and the Board shall authorize recovery of the balance on a straight line basis over a period not to exceed 10 years commencing at the end of the deferral period, and

v. the Board shall accept the need for the Darlington Refurbishment Project in light of the Plan of the Ministry of Energy known as the 2013 Long-Term Energy Plan and the related policy of the Minister endorsing the need for nuclear refurbishment.

13. In making its first order under section 78.1 of the Act that is effective on or after January 1, 2022 setting payment amounts for the hydroelectric facilities, the following rules apply:

i. The order shall provide for a base payment amount for the hydroelectric facilities that is equal to the base payment amount for the hydroelectric facilities on December 31, 2021, and that applies until the effective date of a subsequent order setting payment amounts for the hydroelectric facilities that comes into effect after December 31, 2026.

ii. Subparagraph i applies with respect to only 50 per cent of the output of the Chats Falls generation facility.

14. The Board shall determine the disposition of any balance recorded in the variance account established under subsection 5.7 (1), to the extent the Board is satisfied that,

i. the revenues and costs are accurately recorded in the account,

ii. the costs were prudently incurred, and

iii. the amounts recorded in the account are directly attributable to Pickering B extension activities or Pickering B preservation activities. O. Reg. 23/07, s. 4; O. Reg. 27/08, s. 2; O. Reg. 312/13, s. 4; O. Reg. 353/15, s. 3; O. Reg. 57/17, s. 2; O. Reg. 622/20, s. 3 (1); O. Reg. 739/21, s. 4; O. Reg. 557/22, s. 4; O. Reg. 142/25, s. 3.

(3) For greater certainty, the rule set out in paragraph 13 of subsection (2) does not affect any authority of the Board to approve,

(a) changes to the hydroelectric incentive mechanism applicable to Ontario Power Generation Inc.;

(b) the establishment of or changes to deferral or variance accounts relating to the hydroelectric facilities; or

(c) the recovery of any amounts relating to the hydroelectric facilities that are recorded by Ontario Power Generation Inc. in a deferral or variance account referred to in clause (b), or any related payment amount riders. O. Reg. 622/20, s. 3 (2).

7. Omitted (provides for coming into force of provisions of this Regulation). O. Reg. 53/05, s. 7.

SCHEDULE 1

1. Abitibi Canyon.
2. Alexander.
3. Aquasabon.
4. Arnprior.
5. Auburn.
6. Barrett Chute.
7. Big Chute.
8. Big Eddy.
9. Bingham Chute.
10. Calabogie.
11. Cameron Falls.
12. Caribou Falls.

13. Chats Falls.
14. Chenaux.
15. Coniston.
16. Crystal Falls.
17. Des Joachims.
18. Elliott Chute.
19. Eugenia Falls.
20. Frankford.
21. Hagues Reach.
22. Hanna Chute.
23. High Falls.
24. Indian Chute.
25. Kakabeka Falls.
26. Lakefield.
27. Lower Notch.
28. Manitou Falls.
29. Matabitchuan.
30. McVittie.
31. Merrickville.
32. Meyersberg.
33. Mountain Chute.
34. Nipissing.
35. Otter Rapid.
36. Otto Holden.
37. Pine Portage.
38. Ragged Rapids.
39. Ranney Falls.
40. Seymour.
41. Sidney.
42. Sills Island.
43. Silver Falls.
44. South Falls.
45. Stewartville.
46. Stinson.
47. Trethewey Falls.
48. Whitedog Falls.

O. Reg. 312/13, s. 5; O. Reg. 739/21, s. 5.

SCHEDULE 2

1. PT RDAL BTN: LTS 18 & 19, 20 & 21, 22 & 23, 24 & 25, ALL BF CON (DARLINGTON) CLOSED BY BY-LAW N90910; PT LTS 18, 19, 20, 21, 22, 23 & 24, BF CON (DARLINGTON); LTS 183 TO 754 INCL, 913 TO 1533 INCL, PT LTS 131 TO 133 INCL, 157 TO 182 INCL & 885 TO 912 INCL, STATION RD, FIFTH AVE, SIXTH AVE, SEVENTH AVE, EIGHTH AVE, NINTH AVE, TENTH AVE, ELEVENTH AVE, TWELFH AVE,

THIRTEENTH AVE, FOURTEENTH AVE, FIFTEENTH AVE & SIXTEENTH AVE CLOSED BY BYLAW N90910 & PT SEVENTEENTH AVE, PL 97 (DARLINGTON), PARTS 2, 15, 18 AND 19 PLAN 40R28277 AND PTS 1, 3, 4 & 7 TO 15 INCL, 40R18818, SAVE AND EXCEPT PARTS 1, 2, 3, 4, 5, 13, 14, 15, 16, 17, 18 AND 19 PLAN 40R26289 AND SAVE AND EXCEPT PTS 1, 2, 3, 4, 5, 18 & 19 PLAN 40R28269 AND SAVE AND EXCEPT PTS 8, 9, 10, 11, 12, 13 & 14 PLAN 40R28277; S/T EASE PTS 3, 5, 8, 9 PL 40R20514 AND PTS 14 AND 15 PL 40R28269 AND PT 17 PLAN 40R28277 IN FAVOUR OF PT 9, 40R18818 & PT 1, PL 40R20514 AS IN DR107221; S/T EASE PTS 4, 6, 7, 10 PL 40R20514 AND PT 11 PL 40R20514 SAVE AND EXCEPT PT 8 PL 40R28277 IN FAVOUR OF PT 9, PL 40R18818 & PT 1, PL 40R20514 AS IN DR107221 ; T/W EASE PT LTS 19, 20, 21, PT RDAL BTN LTS 20 & 21, BFC DARLINGTON, PT 1, PL 40R20513 (IN FAVOUR OF PT 9, PL 40R18818 & PT 1, PL 40R20514) AS IN DR107221 ; T/W EASE PT LT 21 BFC DARLINGTON, PT 2, PL 40R20513 (IN FAVOUR OF PT 9, PL 40R18818 & PT 1, PL 40R20514) AS IN DR107221 S/T EASE PT 8, PL 40R18818 IN FAVOUR OF PT 9, PL 40R18818 & PT 1, 40R20514 AS IN DR107229 ; S/T EASE PT 15, PL 40R18818 IN FAVOUR OF PT 9, PL 40R18818 & PT 1, PL 40R20514 AS IN DR107229 ; S/T EASE PT 4, PL 40R18818 IN FAVOUR PT 9, PL 40R18818 & PT 1, PL 40R20514 AS IN DR107229 ; S/T EASE PT 12, PL 40R18818 IN FAVOUR OF PT 9, PL 40R18818 & PT 1, PL 40R20514 AS IN DR107229 ; S/T EASE PT 13, PL 40R18818 IN FAVOUR OF PT 9, PL 40R18818 & PT 1, PL 40R20514 AS IN DR107229 ; S/T EASE PTS 20, 21 & 22, PL 40R20514 IN FAVOUR OF PT 9, PL 40R18818 & PT 1, PL 40R20514 AS IN DR107229 ; S/T EASE PTS 5, 6 & 18, PL 40R20514 IN FAVOUR OF PT 9, PL 40R18818 & PT 1, PL 40R20514 AS IN DR107229 ; S/T EASE PT 17, PL 40R20514 IN FAVOUR OF PT 9, PL 40R18818 & PT 1, PL 40R20514 AS IN DR107229 ; S/T EASE PT 19, PL 40R20514 IN FAVOUR OF PT 9, PL 40R18818 & PT 1, PL 40R20514 AS IN DR107229 ; S/T EASE PTS 23 & 24, PL 40R20514 IN FAVOUR OF PT 9, PL 40R18818 & PT 1, PL 40R20514 AS IN DR107229 ; S/T EASE PT 3, PL 40R20514 IN FAVOUR OF PT 9, PL 40R18818 & PT 1, PL 40R20514 AS IN DR107229 ; S/T EASE PTS 5, 8 & 9, PL 40R20514 IN FAVOUR OF PT 9, PL 40R18818 & PT 1, PL 40R20514 AS IN DR107229; S/T EASE PTS 14 AND 15 PLAN 40R28269 AND PT 17 PL 40R28277 IN FAVOUR OF PT 9, PL 40R18818 & PT 1, PL 40R20514 AS IN DR107229; T/W ROW PT 2, PL 40R20513 IN FAVOUR OF PT 9, PL 40R18818 & PT 1, PL 40R20514 AS IN DR107229; TOGETHER WITH AN EASEMENT AS IN DR1184508; TOGETHER WITH AN EASEMENT AS IN DR1184509; MUNICIPALITY OF CLARINGTON, being all of the lands identified by PIN 26606-0367 (LT) registered in the Land Registry Office for the Land Titles Division of Durham (No. 40).

2. RDAL BTN LTS 24 & 25 CON BROKEN FRONT DARLINGTON CLOSED BY BYLAW N90910, PT LT 23 CON BROKEN FRONT DARLINGTON & PT LT 24 CON BROKEN FRONT DARLINGTON PT 6, 10R94; PT LT 21 CON BROKEN FRONT DARLINGTON & PT LT 22 CON BROKEN FRONT DARLINGTON PTS 1 & 2, 10R342; PT LT 19 CON BROKEN FRONT DARLINGTON & PT LT 20 CON BROKEN FRONT DARLINGTON PT 4, 10R342; PT LT 18 CON BROKEN FRONT DARLINGTON PT 6, 10R342; RDAL BTN LTS 22 & 23 CON BROKEN FRONT DARLINGTON CLOSED BY BYLAW N90910 PT 5, 10R553; RDAL BTN LTS 20 & 21 CON BROKEN FRONT DARLINGTON CLOSED BY BYLAW N90910 PT 3, 10R342; RDAL BTN LTS 18 & 19 CON BROKEN FRONT DARLINGTON CLOSED BY BYLAW N90910 PTS 5 & 9, 10R342; FIRST AV PL 97 DARLINGTON, SECOND AV PL 97 DARLINGTON, THIRD AV PL 97 DARLINGTON & FOURTH AV PL 97 DARLINGTON CLOSED BY BYLAW N90910; LT 1534 PL 97 DARLINGTON; LT 1535 PL 97 DARLINGTON; LT 1536 PL 97 DARLINGTON; LT 1537 PL 97 DARLINGTON; LT 1538 PL 97 DARLINGTON; LT 1539 PL 97 DARLINGTON; LT 1540 PL 97 DARLINGTON; LT 1541 PL 97 DARLINGTON; LT 1542 PL 97 DARLINGTON; LT 1543 PL 97 DARLINGTON; LT 1544 PL 97 DARLINGTON; LT 1545 PL 97 DARLINGTON; LT 1546 PL 97 DARLINGTON; LT 1547 PL 97 DARLINGTON; LT 1548 PL 97 DARLINGTON; LT 1549 PL 97 DARLINGTON; LT 1550 PL 97 DARLINGTON; LT 1551 PL 97 DARLINGTON; LT 1552 PL 97 DARLINGTON; LT 1553 PL 97 DARLINGTON; LT 1554 PL 97 DARLINGTON; LT 1555 PL 97 DARLINGTON; LT 1556 PL 97 DARLINGTON; LT 1557 PL 97 DARLINGTON; LT 1558 PL 97 DARLINGTON; LT 1559 PL 97 DARLINGTON; LT 1560 PL 97 DARLINGTON; LT 1561 PL 97 DARLINGTON; LT 1562 PL 97 DARLINGTON; LT 1563 PL 97 DARLINGTON; LT 1564 PL 97 DARLINGTON; LT 1565 PL 97 DARLINGTON; LT 1566 PL 97 DARLINGTON; LT 1567 PL 97 DARLINGTON; LT 1568 PL 97 DARLINGTON; LT 1569 PL 97 DARLINGTON; LT 1570 PL 97 DARLINGTON; LT 1571 PL 97 DARLINGTON; LT 1572 PL 97 DARLINGTON; LT 1573 PL 97 DARLINGTON; LT 1574 PL 97 DARLINGTON; LT 1575 PL 97 DARLINGTON; LT 1576 PL 97 DARLINGTON; LT 1577 PL 97 DARLINGTON; LT 1578 PL 97 DARLINGTON; LT 1579 PL 97 DARLINGTON; LT 1580 PL 97 DARLINGTON; LT 1581 PL 97 DARLINGTON; LT 1582 PL 97 DARLINGTON; LT 1583 PL 97 DARLINGTON; LT 1584 PL 97 DARLINGTON; LT 1585 PL 97 DARLINGTON; LT 1586 PL 97 DARLINGTON; LT 1587 PL 97 DARLINGTON; LT 1588 PL 97 DARLINGTON; LT 1589 PL 97 DARLINGTON; LT 1590 PL 97 DARLINGTON; LT 1591 PL 97 DARLINGTON; LT 1592 PL 97 DARLINGTON; LT 1593 PL 97 DARLINGTON; LT 1594 PL 97 DARLINGTON; LT 1595 PL 97 DARLINGTON; LT 1596 PL 97 DARLINGTON; * LT 1629 PL 97 DARLINGTON; LT 1630 PL 97 DARLINGTON; LT 1631 PL 97 DARLINGTON; LT 1632 PL 97 DARLINGTON; LT 1633 PL 97 DARLINGTON; LT 1634 PL 97 DARLINGTON; LT 1635 PL 97 DARLINGTON; LT 1636 PL 97 DARLINGTON; LT 1637 PL 97 DARLINGTON; LT 1638 PL 97 DARLINGTON; LT 1639 PL 97 DARLINGTON; LT 1640 PL 97 DARLINGTON; LT 1641 PL 97 DARLINGTON; LT 1642 PL 97 DARLINGTON; LT 1643 PL 97 DARLINGTON; LT 1644 PL 97 DARLINGTON; LT 1645 PL 97 DARLINGTON; LT 1646 PL 97 DARLINGTON; LT 1647 PL 97 DARLINGTON; LT 1648 PL 97 DARLINGTON; LT 1649 PL 97 DARLINGTON; LT 1650 PL 97 DARLINGTON; LT 1651 PL 97

DARLINGTON; LT 1652 PL 97 DARLINGTON; LT 1653 PL 97 DARLINGTON; LT 1654 PL 97 DARLINGTON; LT 1655 PL 97 DARLINGTON; LT 1656 PL 97 DARLINGTON; LT 1657 PL 97 DARLINGTON; LT 1658 PL 97 DARLINGTON; LT 1659 PL 97 DARLINGTON; LT 1660 PL 97 DARLINGTON; LT 1661 PL 97 DARLINGTON; LT 1662 PL 97 DARLINGTON; LT 1663 PL 97 DARLINGTON; LT 1664 PL 97 DARLINGTON; LT 1665 PL 97 DARLINGTON; LT 1666 PL 97 DARLINGTON; LT 1667 PL 97 DARLINGTON; LT 1668 PL 97 DARLINGTON; LT 1669 PL 97 DARLINGTON; LT 1670 PL 97 DARLINGTON; LT 1671 PL 97 DARLINGTON; LT 1672 PL 97 DARLINGTON; LT 1673 PL 97 DARLINGTON; LT 1674 PL 97 DARLINGTON; LT 1675 PL 97 DARLINGTON; LT 1676 PL 97 DARLINGTON; LT 1677 PL 97 DARLINGTON; LT 1678 PL 97 DARLINGTON; LT 1679 PL 97 DARLINGTON; LT 1680 PL 97 DARLINGTON; LT 1681 PL 97 DARLINGTON; LT 1682 PL 97 DARLINGTON; LT 1683 PL 97 DARLINGTON; LT 1684 PL 97 DARLINGTON; LT 1685 PL 97 DARLINGTON; LT 1686 PL 97 DARLINGTON; LT 1687 PL 97 DARLINGTON; LT 1688 PL 97 DARLINGTON; LT 1689 PL 97 DARLINGTON; LT 1690 PL 97 DARLINGTON; LT 1691 PL 97 DARLINGTON; LT 1692 PL 97 DARLINGTON; LT 1693 PL 97 DARLINGTON; LT 1694 PL 97 DARLINGTON; LT 1695 PL 97 DARLINGTON; LT 1696 PL 97 DARLINGTON; LT 1697 PL 97 DARLINGTON; LT 1698 PL 97 DARLINGTON; LT 1699 PL 97 DARLINGTON; LT 1700 PL 97 DARLINGTON; LT 1701 PL 97 DARLINGTON; LT 1702 PL 97 DARLINGTON; LT 1703 PL 97 DARLINGTON; LT 1704 PL 97 DARLINGTON; LT 1705 PL 97 DARLINGTON; LT 1706 PL 97 DARLINGTON; LT 1707 PL 97 DARLINGTON; LT 1708 PL 97 DARLINGTON; LT 1709 PL 97 DARLINGTON; LT 1710 PL 97 DARLINGTON; LT 1711 PL 97 DARLINGTON; LT 1712 PL 97 DARLINGTON; LT 1713 PL 97 DARLINGTON; LT 1714 PL 97 DARLINGTON; LT 1715 PL 97 DARLINGTON; LT 1716 PL 97 DARLINGTON; LT 1717 PL 97 DARLINGTON; LT 1718 PL 97 DARLINGTON; LT 1719 PL 97 DARLINGTON; LT 1720 PL 97 DARLINGTON; LT 1721 PL 97 DARLINGTON; LT 1722 PL 97 DARLINGTON; LT 1723 PL 97 DARLINGTON; LT 1724 PL 97 DARLINGTON; LT 1725 PL 97 DARLINGTON; LT 1726 PL 97 DARLINGTON; LT 1727 PL 97 DARLINGTON; LT 1728 PL 97 DARLINGTON; LT 1729 PL 97 DARLINGTON; LT 1730 PL 97 DARLINGTON; LT 1731 PL 97 DARLINGTON; LT 1732 PL 97 DARLINGTON; LT 1733 PL 97 DARLINGTON; LT 1734 PL 97 DARLINGTON; LT 1735 PL 97 DARLINGTON; LT 1736 PL 97 DARLINGTON; LT 1737 PL 97 DARLINGTON; LT 1738 PL 97 DARLINGTON; LT 1739 PL 97 DARLINGTON; LT 1740 PL 97 DARLINGTON; LT 1741 PL 97 DARLINGTON; *LTS 1597 TO 1628 INCL, PL 97 DARLINGTON* ; CLARINGTON. *AMENDED 2000 08 24 BY T.CUTLER S/T EASE PTS 1 & 2, PL 40R21513 AS IN DR107221; S/T EASE PT 2, PL 40R20513 AS IN DR107229; TOGETHER WITH AN EASEMENT AS IN DR1184508; TOGETHER WITH AN EASEMENT AS IN DR1184509, being all of the lands identified by PIN 26606-0134 (LT) registered in the Land Registry Office for the Land Titles Division of Durham (No. 40).

O. Reg. 739/21, s. 6; O. Reg. 557/22, s. 5.

Français

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Ontario Energy Board Act, 1998

S.O. 1998, CHAPTER 15
Schedule B

Consolidation Period: From June 5, 2025 to the e-Laws currency date.

Last amendment: 2025, c. 4, Sched. 6.

Payments to prescribed generator

78.1 (1) The IESO shall make payments to a generator prescribed by the regulations with respect to output that is generated by a unit at a generation facility prescribed by the regulations. 2014, c. 7, Sched. 23, s. 7.

Payment amount

(2) Each payment referred to in subsection (1) shall be the amount determined in accordance with the order of the Board then in effect. 2014, c. 7, Sched. 23, s. 7.

Same, limitation re Ontario Power Generation Inc.

(3) The determination of a payment to Ontario Power Generation Inc. under this section shall not include any consideration of amounts related to activities of Ontario Power Generation Inc. carried out in relation to the *Ontario Fair Hydro Plan Act, 2017*. 2017, c. 16, Sched. 1, s. 44 (3).

Same

(3.1) The amounts referred to in subsection (3) include, without limitation, the following:

1. Amounts related to the appointment of Ontario Power Generation Inc. as the Financial Services Manager under the *Ontario Fair Hydro Plan Act, 2017*.
2. Amounts related to the charging of fees for performing duties as the Financial Services Manager.
3. Amounts related to exercising the powers and performing the duties of the Financial Services Manager.
4. Amounts related to the consolidation of the assets and liabilities for accounting purposes of the Fair Hydro Trust within the meaning of the *Ontario Fair Hydro Plan Act, 2017*. 2017, c. 16, Sched. 1, s. 44 (3); 2019, c. 6, Sched. 3, s. 12 (3).

Same

(3.2) A payment to Ontario Power Generation Inc. under this section shall not include any amounts that may be specified by the regulations relating to its activities under Part II.1 of the *Electricity Act, 1998*. 2022, c. 23, Sched. 1, s. 5.

Board orders

(4) The Board shall make an order under this section in accordance with the rules prescribed by the regulations and may include in the order conditions, classifications or practices, including rules respecting the calculation of the amount of the payment. 2004, c. 23, Sched. B, s. 15.

Fixing other prices

(5) The Board may fix such other payment amounts as it finds to be just and reasonable,

(a) on an application for an order under this section, if the Board is not satisfied that the amount applied for is just and reasonable; or

(b) at any other time, if the Board is not satisfied that the current payment amount is just and reasonable. 2004, c. 23, Sched. B, s. 15.

Burden of proof

(6) Subject to subsection (7), the burden of proof is on the applicant in an application made under this section. 2004, c. 23, Sched. B, s. 15.

Order

(7) If the Board on its own motion or at the request of the Minister commences a proceeding to determine whether an amount that the Board may approve or fix under this section is just and reasonable,

(a) the burden of establishing that the amount is just and reasonable is on the generator; and

(b) the Board shall make an order approving or fixing an amount that is just and reasonable. 2004, c. 23, Sched. B, s. 15.

Application

(8) Subsections (4), (5) and (7) apply only on and after the day prescribed by the regulations for the purposes of subsection (2). 2004, c. 23, Sched. B, s. 15.

Section Amendments with date in force (d/m/y)

2004, c. 23, Sched. B, s. 15 - 01/01/2005

2014, c. 7, Sched. 23, s. 7 - 01/01/2015

2017, c. 16, Sched. 1, s. 44 (3) - 01/06/2017

2019, c. 6, Sched. 3, s. 12 (3) - 01/11/2019

2022, c. 23, Sched. 1, s. 5 - 15/03/2023

Ontario

Electricity Generation Licence

EG-2023-0231

Ontario Power Generation Inc.

Valid Until

October 2, 2043

Brian Hewson
Vice President, Consumer Protection & Industry Performance
Ontario Energy Board
Date of Issuance: October 3, 2023
Date of Amendment: August 28, 2025

Ontario Energy Board	Commission de l'énergie de l'Ontario
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PART 1 GENERAL CONDITIONS

1 Definitions

In this Licence:

"**Act**" means the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, Schedule B;

"**Electricity Act**" means the *Electricity Act, 1998*, S.O. 1998, c. 15, Schedule A;

"**generation facility**" means a facility for generating electricity or providing ancillary services, other than ancillary services provided by a transmitter or distributor through the operation of a transmission or distribution system and includes any structures, equipment or other things used for that purpose;

"**Licensee**" means Ontario Power Generation Inc.;

"**regulation**" means a regulation made under the Act or the Electricity Act;

2 Interpretation

2.1 In this Licence words and phrases shall have the meaning ascribed to them in the Act or the Electricity Act. Words or phrases importing the singular shall include the plural and vice versa. Headings are for convenience only and shall not affect the interpretation of this Licence. Any reference to a document or a provision of a document includes an amendment or supplement to, or a replacement of, that document or that provision of that document. In the computation of time under this Licence where there is a reference to a number of days between two events, they shall be counted by excluding the day on which the first event happens and including the day on which the second event happens. Where the time for doing an act expires on a holiday, the act may be done on the next day that is not a holiday.

3 Authorization

3.1 The Licensee is authorized, under Part V of the Act and subject to the terms and conditions set out in this licence:

a) to generate electricity or provide ancillary services for sale through the IESO-administered markets or directly to another person subject to the conditions set out in this Licence. This Licence authorizes the Licensee only in respect of those facilities set out in Schedule 1;

b) to purchase electricity or ancillary services in the IESO-administered markets or directly from a generator subject to the conditions set out in this Licence; and

c) to sell electricity or ancillary services through the IESO-administered markets or directly to another person, other than a consumer, subject to the conditions set out in this Licence.

3.2 The Licensee is authorized to conduct business in the name under which this Licence is issued, or any trade name(s) listed in Schedule 2.

4 Obligation to Comply with Legislation, Regulations and Market Rules

4.1 The Licensee shall comply with all applicable provisions of the Act and the Electricity Act, and regulations under these acts, except where the Licensee has been exempted from such compliance by regulation.

4.2 The Licensee shall comply with all applicable Market Rules.

5 Obligation to Maintain System Integrity

5.1 Where the IESO has identified, pursuant to the conditions of its licence and the Market Rules, that it is necessary for purposes of maintaining the reliability and security of the IESO-controlled grid, for the Licensee to provide energy or ancillary services, the IESO may require the Licensee to enter into an agreement for the supply of energy or such services.

5.2 Where an agreement is entered into in accordance with paragraph 5.1, it shall comply with the applicable provisions of the Market Rules or such other conditions as the Board may consider reasonable. The agreement shall be subject to approval by the Board prior to its implementation. Unresolved disputes relating to the terms of the Agreement, the interpretation of the Agreement, or amendment of the Agreement, may be determined by the Board.

6 Restrictions on Certain Business Activities

6.1 Neither the Licensee, nor an affiliate of the Licensee shall acquire an interest in a transmission or distribution system in Ontario, construct a transmission or distribution system in Ontario or purchase shares of a corporation that owns a transmission or distribution system in Ontario except in accordance with section 81 of the Act.

7 Provision of Information to the Board

7.1 The Licensee shall maintain records of and provide, in the manner and form determined by the Board, such information as the Board may require from time to time.

7.2 Without limiting the generality of paragraph 7.1 the Licensee shall notify the Board of any material change in circumstances that adversely affects or is likely to adversely affect the business, operations or assets of the Licensee, as soon as practicable, but in any event no more than twenty (20) days past the date upon which such change occurs.

8 Term of Licence

8.1 This Licence shall take effect on October 3, 2023 and expire on October 2, 2043. The term of this Licence may be extended by the Board.

9 Fees and Assessments

9.1 The Licensee shall pay all fees charged and amounts assessed by the Board.

10 Communication

10.1 The Licensee shall designate a person that will act as a primary contact with the Board on matters related to this Licence. The Licensee shall notify the Board promptly should the contact details change.

10.2 All official communication relating to this Licence shall be in writing.

10.3 All written communication is to be regarded as having been given by the sender and received by the addressee:

a) when delivered in person to the addressee by hand, by registered mail or by courier;

b) ten (10) business days after the date of posting if the communication is sent by regular mail; or

c) when received by facsimile transmission by the addressee, according to the sender=s transmission report.

11 Copies of the Licence

11.1 The Licensee shall:

a) make a copy of this Licence available for inspection by members of the public at its head office and regional offices during normal business hours; and

b) provide a copy of this Licence to any person who requests it. The Licensee may impose a fair and reasonable charge for the cost of providing copies.

PART 2 PRICE CAP AND REBATE

1 Definitions and Interpretation

In Parts 2 through 5 inclusive of these Licence Conditions:

"**Average Price**" or "AP" is the price against which the Price Cap is compared to determine whether a Rebate is required in respect of a Settlement Period. The Average Price is determined by summing the product of the Hourly Price multiplied by the Contract Weight for all hours of that Settlement Period;

"**Changes in Law**" means changes in law (including without limitation environmental laws, laws affecting OPGI's generation facilities, tax laws and the general laws affecting the regulation of electricity in Ontario), but excluding provincial tax laws and, for greater certainty, excluding changes in licence conditions and market rules;

"**Contract Required Quantity**" or "CRQ" means the quantity of energy upon which any Rebate is determined, in respect of a Settlement Period, as set forth in the Model Output Data and as may be modified pursuant hereto. Subject to such adjustments, the CRQ will equal the sum of all Hourly Quantities for all hours in a Settlement Period;

"**Contract Weight**" or "CW_h" means the weighting for each hour in a Settlement Period, h, that is used to calculate the Average Price. For any particular hour, the Contract Weight equals the Hourly Quantity for that hour divided by the CRQ for that Settlement Period;

"**Effective Control**" in respect of output means control over the timing, quantity and bidding into the Ontario market of such output;

"***Force Majeure Adjustment***" or "FMA" means a reduction in the Rebate as a result of a *Force Majeure* Event;

"***Force Majeure* Event**" means an event defined in clause 2(c)(ii) of Part 2 below;

"***Force Majeure* Replacement Cost**" or "$FMRC_h$" means, for any particular hour in a Settlement Period, h, the predetermined net incremental replacement cost for each OPGI generation unit, as set forth in the Model Output Data that is used in determining the Force Majeure Adjustment, and as may be modified pursuant hereto. $FMRC_h$ may be constant in the Model Output Data over the hours in a month or other period;

"**Hourly Quantity**" or "Q_h" means, for any particular hour in a Settlement Period, h, the quantity of energy upon which the Contract Weight is established, as set forth in the Model Output Data. The sum of the Hourly Quantities for all hours in a Settlement Period equals the CRQ for that Settlement Period;

"**Hourly Price**" or "P_h" means, for any particular hour in a Settlement Period, h, the unconstrained spot price for energy for that hour expressed in a price in $ per MWh, as determined by the IESO pursuant to its market rules;

"**Hourly Reserve Capacity Price**" is the hourly market clearing price of reserve capacity;

"**Hourly Unit Quantity**," or "q^i_h" means, for any particular hour in a Settlement Period, h, the hourly quantity of energy associated with a particular OPGI generation unit, i, upon which the Hourly Quantity is established, as set forth in the Model Output Data. The sum of all Hourly Unit Quantities for all OPGI generation units in respect of an hour equals the Hourly Quantity for that hour;

"**Locational Spot Price**" means, for any particular hour in a Settlement Period, h, and any particular OPGI generation unit, the spot price for energy at such generation unit's interconnection, which will only apply if location-based marginal pricing is developed in Ontario;

"**Model Output Data**" means the data filed with the Board. The Model Output Data contains data, some of which is confidential, derived from a production cost model of the electricity market in Ontario and neighbouring regions under the assumption that OPGI is assumed to bid its generation units in a manner that achieves an average sales price of $ 38/MWh. The resulting CRQ, Q_h, and q^i_h data reflects 90 per cent of OPGI's predicted sales to Ontario customers;

"**OPGI**" means Ontario Power Generation Inc.

"**Potential *Force Majeure* Event**" means an event defined in clause 2(c)(i) of Part 2 below;

"**Price Cap**" or "CAP" means $38/MWh, which is the threshold used in calculating the Rebate;

"**Price Spike Adjustment**" or "PSA" means the reduction in the Rebate as a result of qualifying price spikes, as calculated pursuant hereto;

"**Prime Rate**" means the variable annual rate of interest, calculated on the basis of a calendar year, announced from time to time by the IESO's then principal Canadian banker as the reference rate of interest (commonly known as its prime rate) then in effect and used by such bank for determining interest rates on Canadian dollar denominated commercial loans made by it in Canada to customers of varying degrees of credit-worthiness;

"**Rebate" or "R**" means the amount OPGI must pay the IESO as a consequence of the Average Price in any Settlement Period exceeding the Price Cap, less any applicable adjustments;

"**Rebate Carryforward Adjustment**" or "RCA" means the adjustment in which negative Rebates from a Settlement Period are used to offset Rebates in subsequent Settlement Periods;

"**Reserve Capacity Ratio**" is a number greater than 1, such as 1.2, that is set by the IESO for the purposes of multiplying by the hourly demand to determine the reserve capacity target in such hour;

"**Settlement Period**" means each time period over which OPGI's compliance with the Price Cap shall be measured, which shall be over a 12 month period, except that (1) the first Settlement Period shall commence on the opening of the competitive electricity market and shall consist of the first full 12 calendar months plus the days, if any, in the first partial month; and (2) the last Settlement Period shall end on the termination of the provisions of Part 2, and therefore could be less than 12 full calendar months; and

"**Tier 1**" capacity means all nuclear and hydroelectric generation in Ontario and "**Tier 2**" capacity means that portion of Ontario's generation capacity, including inter-tie capacity and demand-side bidding, that is not part of Tier 1 capacity. For such purposes, generation capacity shall be based upon the maximum continuous rating of a unit, inter-tie capacity shall be based on the average of summer and winter season Ontario transfer capacity, and demand-side bidding shall be based on the sum of the dispatchable and interruptible loads, all expressed in MW.

All dollar amounts referred to are expressed in Canadian dollars.

2 Determination of Rebate

OPGI shall pay a Rebate to the IESO in respect of each Settlement Period in which the Average Price (AP) exceeds the Price Cap (CAP). The amount of the Rebate shall be determined in accordance with the following formula:

R = [(AP - CAP) * CRQ] - (RCA + PSA + FMA)

If the calculated Rebate in respect of any Settlement Period is a negative number, then there shall be no Rebate, and the Rebate Carryforward Adjustment shall be changed as described herein.

(a) *Rebate Carryforward Adjustment*

Initially, the Rebate Carryforward Adjustment ("RCA") shall be zero. In any Settlement Period in respect of which the calculated Rebate is negative, the absolute value of that amount shall be the Rebate Carryforward Adjustment for the purposes of the next Settlement Period.

(b) *Price Spike Adjustment*

A Price Spike Adjustment (PSA) shall be calculated for all hours in a Settlement Period in which both (1) the Hourly Price (P_h) exceeds $125/MWh, and (2) OPGI's Generation for that hour is less than the Hourly Quantity (Q_h). The PSA for a Settlement Period shall equal the sum of the adjustments for each applicable hour, which shall be calculated pursuant to the following formula:

PSA = (P_h - $125/MWh) * ($Q_h$ – OPGI's Generation for that hour)

where OPGI's Generation for that hour = OPGI's energy generated from all sources in Ontario (metered as per IESO market rules) the output of which is Effectively Controlled by OPGI and which was included as OPGI energy generated in the Model Output Data, and includes the current power purchase agreement with Manitoba Hydro.

(c) *Force Majeure* Adjustment

(i) Potential *Force Majeure* Event

A Potential *Force Majeure* Event is any event consisting of any of the following conditions or events that results in the loss or failure of, or the inability to operate, in whole or in part, one or more generation units in Ontario the output of which is Effectively Controlled by OPGI and that, in each case, is beyond the reasonable control of OPGI and which is not a result of OPGI's failure to comply with pre-existing laws or licence conditions or market rules or to reasonably maintain or to use its best efforts to promptly repair any generation unit or units:

(A) acts of war, revolution, riot, sabotage, occupation or vandalism;

(B) earthquakes, tornadoes or severe storms;

(C) other acts of God;

(D) local, regional or national states of emergency;

(E) strikes or other labour disputes;

(F) other failure or damage to an OPGI generating facility, including failure or damage caused by construction defects, fire, or damage to necessary equipment and which is not a result of negligence in the maintenance or repair thereof;

(G) interruptions in the supply of fuel or other essential supplies (excluding variations in water supplies in the case of hydroelectric generation units);

(H) failure of transmission or distribution facilities in Ontario;

(I) other system emergencies in Ontario; and

(J) Changes in Law.

(ii) Definition of *Force Majeure* Event

A *Force Majeure* Event is either an Isolated *Force Majeure* Event or a Cumulative *Force Majeure* Event.

An Isolated *Force Majeure* Event is that portion of any Potential *Force Majeure* Event that occurs after the Potential *Force Majeure* Event has caused a reduction in the energy actually generated by the applicable units greater than

250,000 MWh from the sum of such units' Hourly Unit Quantities during the effectiveness of such Potential *Force Majeure* Event.

A Cumulative *Force Majeure* Event occurs in a Settlement Period when the cumulative reduction in that Settlement Period of energy actually generated by affected generation units in Ontario the output of which is Effectively Controlled by OPGI caused by Potential *Force Majeure* Events exceeds 500,000 MWh when compared to the sum of such affected units' Hourly Unit Quantities during the effectiveness of such Potential *Force Majeure* Events. OPGI will, where applicable, designate within 15 days following the end of the applicable Settlement Period that portion of Potential *Force Majeure* Events that is in excess of 500,000 MWh and that qualifies as a Cumulative *Force Majeure* Event.

A Potential *Force Majeure* Event, or a portion of a Potential *Force Majeure* Event, that qualifies as both an Isolated *Force Majeure* Event or a Cumulative *Force Majeure* Event may at the discretion of OPGI within 15 days following the end of the applicable Settlement Period be designated as either type of *Force Majeure* Event, but not as both, and, for greater certainty, a Potential Force Majeure Event designated as one type of *Force Majeure* Event by OPGI shall not be treated for purposes of determining whether the other type of *Force Majeure* Event has occurred.

(iii) *Force Majeure* Adjustment

A Force Majeure Adjustment (FMA) in respect of any Settlement Period shall be equal to the sum, for all generation units the output of which is Effectively Controlled by OPGI subject to *Force Majeure* Events, of the *Force Majeure* Replacement Cost ($FMRC_h$) in respect of each applicable unit for each hour during the effectiveness of each *Force Majeure* Event in respect of such unit during the Settlement Period, less any insurance or other recovery in respect of such loss or deemed loss.

The *Force Majeure* Adjustment in respect of any Settlement Period for each generation unit the output of which is Effectively Controlled by OPGI whose generation is reduced as a consequence of a *Force Majeure* Event shall be calculated pursuant to the following formula, prior to any recovery adjustment:

$$\mathbf{\sum_h [q^i_h \ * \ FMRCh * ((Capacity - Reduced\ Capacity_h)/Capacity)]}$$

where:
Capacity = the maximum continuous rating of the unit at the time of the *Force Majeure* Event (at normal head for hydroelectric generation units);
and
Reduced Capacity_h = the reduced capacity in an hour of the unit as a consequence of and during the effectiveness of the *Force Majeure* Event.

(iv) Adjustment to *Force Majeure* Replacement Cost

In the event that over 2,000 MW of OPGI generating capacity the output of which is Effectively Controlled by OPGI qualifies for a particular *Force Majeure* Event, OPGI shall have the right to petition the Board to increase the amount of the *Force Majeure* Replacement Cost in respect of one or more affected unit(s) in the applicable hours, which petition shall be granted if OPGI can demonstrate to the Board's satisfaction higher incremental replacement costs (net of any variable costs avoided as a consequence of the *Force Majeure* Event) than those set forth in the Model Output Data.

(v) Notice

OPGI shall promptly notify the IESO of any *Force Majeure* Event claimed by OPGI and shall provide the IESO with all information reasonably required to verify the *Force Majeure* Event and to calculate the *Force Majeure* Adjustment.

3 Conduct of OPGI

3.1 OPGI may engage in unilateral actions to attempt to maintain Hourly prices at levels that will result in the Average Price for a Settlement Period equaling the Price Cap, plus all adjustments provided for in Part 2, Section 2 above. In the event that unilateral actions taken by OPGI cause the Average Price to exceed such a level, the sole remedy shall be for OPGI to pay the Rebate as provided for in paragraph 2 of Part 2 above.

4 Reduction to CRQ and Q_h Upon Decontrol

(a) *Unadjusted Reductions*

Except as may be provided in (b) below, in the event that OPGI completes the transfer of Effective Control over the output of a generation unit, as determined by the Board under Part 3, then Q_h for each hour in respect of the current and any subsequent Settlement Period shall be reduced by 110 percent of the q^i_h of the transferred unit for each hour subsequent to the completion of the transfer. As a result, the CRQ in respect of each applicable Settlement Period shall be reduced by these reductions in Q_h.

(b) *Adjustment Necessitated by Environmental Laws*

In the event that OPGI transfers Effective Control over the output of a generation unit and the transferee, at the date of completion of the transfer, does not have and cannot reasonably obtain sufficient environmental emission permits or other environmental authorizations ("emission permits"), in respect of the applicable hours in the period commencing following the completion of the transfer of Effective Control (the "applicable hours"), to enable the unit's potential output during the applicable hours (the "transferred permitted output") to meet or exceed 110 percent times the sum for the applicable hours of the q^i_h of such unit (the "transferred output"), whether as the result of a change in environmental laws or otherwise, then:

(i) any adjustment to Q_h and CRQ otherwise provided for in (a) above will reduced by the proportion that the transferred permitted output is of the transferred output, subject to (ii) below;

(ii) in circumstances where OPGI's remaining emission permits following the transfer of Effective Control are not sufficient to enable its remaining output during the applicable hours (the "remaining permitted output") to meet or exceed 110 percent times the sum for the applicable hours of the q^i_h's of its remaining units, (the "remaining output"), then, in lieu of the adjustment provided for in (i) above, any adjustment to Q_h and CRQ otherwise provided for in (a) above will be multiplied by the result of the following formula, which if greater than 1.0 shall be deemed to be equal to 1.0:

(transferred permitted output/transferred output)/
(remaining permitted output/remaining output); and

(iii) where the transferee's emission permits are affected by more than one substance, then the resulting adjustment to Q_h and CRQ otherwise provided for in (i) or (ii) above will be that which operates to constrain the transferee's output.

5 Administration of Rebate

5.1 OPGI shall enter into and comply with a settlement agreement with the IESO consistent with the document attached as Schedule A and B to this licence.

6 Capacity Reserve Market

6.1 In the event that a capacity reserve market is developed in Ontario at any time while the provisions of Part 2 are in effect, then:

(a) the following definition of "Average Price" or "AP" shall be used in lieu of the definition provided for in paragraph 1 of Part 2 above:

"Average Price" or "AP" is the price against which the Price Cap is compared to determine whether a Rebate is required in respect of a Settlement Period. The Average Price is determined by using the following formula:

AP=

$$\sum_{h}[CW_h * [P_h + (\text{Hourly Reserve Capacity Price} * \text{Reserve Capacity Ratio})]]$$

(b) the Price Spike Adjustment shall be calculated according to the following formula in lieu of the formula provided for in paragraph 2(b) of Part 2 above:

PSA = [(P_h + Hourly Reserve Capacity Price * Reserve Capacity Ratio) - $125/MWh] * ($Q_h$ – OPGI's Generation for that hour);

(c) OPGI may apply to the Board for adjustments to (a) or (b) above if necessary or desirable depending upon the precise nature of the capacity reserve market introduced.

7 Location-Based Marginal Pricing

In the event that location-based marginal pricing is developed in Ontario at any time while the provisions of Part 2 are in effect, then:

(a) the following definition of "Average Price" or "AP" shall be used in lieu of the definition provided for in paragraph 1 of Part 2 above:

"Average Price" or "AP" is the price against which the Price Cap is compared to determine whether a Rebate is required in respect of a Settlement Period. The Average Price is determined by using the following formula:

AP=

$$\sum_{h,i} (\text{Locational Spot Price} * q^i_h)/CRQ$$

(b) the Hourly Price, or P_h, for purposes of determining if a price spike has occurred and in order to calculate the Price Spike Adjustment in each applicable hour, shall be the average price of energy OPGI sells into the IESO spot market in that hour, which average price shall be determined by dividing OPGI's hourly spot market revenue in $ by the quantity (calculated in MWh) of OPGI's spot market sales; and

(c) OPGI may apply to the Board for adjustments to (a) or (b) above if necessary or desirable depending upon the precise nature of the location-based marginal pricing introduced.

8 Capacity Reserve Market and Location-Based Marginal Pricing

In the event that both a capacity reserve market and location-based marginal pricing are developed in Ontario at any time while the provisions of Part 2 are in effect, then:

(a) the following definition of "Average Price" or "AP" shall be used in lieu of the definitions provided for in paragraphs 1, 6 or 7 of Part 2 above:

"Average Price" or "AP" is the price against which the Price Cap is compared to determine whether a Rebate is required in respect of a Settlement Period. The Average Price is determined by using the following formula:

$$\mathbf{AP} = \sum_{h}[\mathbf{CW_h} * (\text{Hourly Reserve Capacity Price} * \text{Reserve Capacity Ratio})]$$

$$+ \sum_{h,i} (\text{Locational Spot Price} * q^{i}_{h})/\text{CRQ}$$

(b) the Price Spike Adjustment shall be calculated according to the following formula in lieu of the formula provided for in paragraphs 2(b) or 6 of Part 2 above:

$$\mathbf{PSA} = [(\text{Hourly Reserve Capacity Price} * \text{Reserve Capacity Ratio})$$

$$+ \sum_{i} ((\text{Locational Spot Price} * q^{i}_{h})/Q_{h}) - \$125/\text{MWh}]$$

$$* (Q^{h} - \text{OPGI's Generation for that hour});$$

(c) OPGI may apply to the Board for adjustments to (a) or (b) above if necessary or desirable depending upon the precise nature of the capacity reserve market or location-based marginal pricing introduced.

9 Additional Adjustment for Changes in Law

If one or more Changes in Law cause or are reasonably expected to cause a decrease in OPGI's net annual income equal to or greater than $60,000,000, then, rather than treating such Changes in Law as a Force Majeure Event for purposes of paragraph 2 above, OPGI may apply to the Board for a variation in the CRQ, Rebate, and/or the Price Cap methodology in respect of the Settlement Period in which the Change in Law occurs and all subsequent Settlement Periods the Change in Law is reasonably expected to affect in order to ensure that OPGI is not materially adversely affected as a result, taking into account all Changes in Law and whether the net effect of these Changes in Law have benefited or are reasonably likely to benefit OPGI during the same time period or any prior or subsequent time period.

10 Termination of Part 2

Beginning April 1, 2005 the OPG rebate calculation will be determined by the formula set out in Schedule B - Additional Terms and Conditions of Settlement Agreement Between IESO & OPG as amended from time to time.

PART 3 TRANSFER OF EFFECTIVE CONTROL

[Part 3 is revoked, effective December 7, 2005]

PART 4 INBOUND TRANSMISSION RIGHTS AND IMPORT LIMITS

1 Definitions and Interpretation

In this Part 4, “season” means the winter period (the “winter season”) from and including November 1 until and including April 30 of the following year or the summer period (the “summer season”) from and including May 1 until and including October 31 of the same year, as applicable.

2 Inter-tie and Import Limits

(a) OPGI shall not import energy into Ontario in excess of the energy import limits set forth in (b) below. In no event shall a purchase from the IESO spot market in Ontario be construed as an import of energy into Ontario for such purposes.

(b) The energy import limits referred to in (a) above are:

(i) 7.24 TWh during the winter season (increased to 7.28 TWh in a leap year); and

(ii) 6.58 TWh during the summer season;

all of which figures shall be increased, at the in service date of new or upgraded inter-tie facilities, by 35 percent times the number of hours in a season multiplied by any applicable net increase in inter-tie capacity in Ontario as determined by the IESO from that in effect on the date of the opening of the competitive electricity market. For such purposes, inter-tie capacity shall be based on the Ontario transfer capacity in the applicable season.

(c) The foregoing provisions of paragraph 2 shall not be required to be complied with by OPGI with the IESO’s consent in an emergency situation.

3 Export Limits

Unless otherwise provided herein, none of the provisions of Parts 2 through 5 shall limit OPGI’s ability to export energy from Ontario.

PART 5 MARKET BASED ANCILLARY SERVICES

(Note: Market based ancillary services are currently comprised of Operating Reserves only, but the principles outlined herein suggest a framework that could be used for other market based ancillary services.)

Unless the IESO has determined, based on the number of independently controlled competing alternatives and other circumstances in its discretion, that a competitive market for any category of operating reserves (i.e. 10-minute and 30-minute) exists, OPGI shall be required to comply with the following requirements:

(a) subject to (a.1), the price to be offered by OPGI associated with each category of OPGI operating reserve services will not exceed a cap to be contained in an agreement to be negotiated between OPGI and the IESO, which cap will be designed, taking into account the relevant IESO market rules, to compensate OPGI for its actual cost of providing such operating reserve services, including additional operating and maintenance costs, additional fuel costs, additional opportunity costs associated with providing such operating reserve services from OPGI hydroelectric generation units, and a reasonable rate of return on incremental capital needed to provide such operating reserve services, and which agreement shall require OPGI to offer the maximum available amount of each category of operating reserve services, consistent with good utility practices, for each OPGI generation unit capable of providing such services;

(a.1) notwithstanding (a) above, save and except where the IESO has advised OPGI that specific units are required to offer in for reliability, OPGI may offer less than the maximum available amount of any category of operating reserve where this is necessary in order for OPGI to satisfy its obligations under, or to give effect to, any shareholder declaration or resolution of the Minister of Energy in effect at the relevant time relating to, or any Regulation made under the *Environmental Protection Act* (Ontario) relating to, carbon dioxide (CO_2) emissions arising from the use of coal at OPGI's coal-fired generation stations;

(b) subject to (a.1), in the event that the agreement referred to in (a) above cannot be reached, the terms of such agreement shall be determined through binding commercial arbitration by a mutually agreed independent arbitrator on agreed terms of arbitration;

(c) subject to (a.1), in the event that either OPGI or the IESO subsequently determines that the operation of the market is such that the intent of the agreement referred to in (a) or (b) above is materially frustrated, then OPGI and the IESO shall negotiate amendments (which may be retroactive) to the terms of such agreement with a view to correcting such situation and, in the event that they cannot agree on such amendments, the amendments, if any, shall be determined through binding commercial arbitration by a mutually agreed independent arbitrator on agreed terms of arbitration;

(d) subject to (a.1), OPGI shall comply with the terms of the agreement referred to in (a) or (b) above, as it may be amended under (c) above;

(e) subject to (a.1), pending reaching an agreement, or pending the resolution of any dispute, the IESO may at any time set the price cap and terms on which OPGI must provide any category of operating reserve services, subject to later adjustment upon final agreement or final resolution of the dispute with interest at the Prime Rate, calculated and accrued daily; and

(f) subject to (a.1), if the IESO's market rules at any time are such that the market clearing price for a category of operating reserve services does not include both the offer price and the opportunity cost of the marginal unit providing the service, and the agreement referred to in (a) or (b) above has not taken such factors into account, then the agreement referred to in (a) or (b) above shall be considered to have been materially frustrated for purposes of (c) above.

PART 6 BRUCE DECONTROL RELATED CONDITIONS

1. The Licensee shall implement a Ring-Fence plan in accordance with the plans referred to in Section 8A of OPG's pre-filed evidence, and as detailed more fully in Interrogatory Responses I 6.5, and I 15.13 of RP-2002-0142, with the following exception:

   a) Only commercially sensitive information will be captured by the Ring-Fence plan. For clarity, this consists of Bruce Power outage information not already in the public domain and unit condition information only.

2. The Licensee shall conduct internal audits of the Ring-Fence plan every two calendar years.

3. The Licensee must provide to the Board every year a self-certification statement signed by both the Chief Executive Officer and the Senior Regulatory Officer or other Senior Officer of OPG that the Ring-Fence plan methodology is operational for the activities that remain ring-fenced.

4. OPG shall make Status Reports to the Board within 30 days of:

   a. Any additional agreements entered into with BP LP;

   b. Any amendments, replacements or extensions of existing agreements with BP LP; and

   c. Expired agreements under the Bruce Transaction.

5. Prior to May 1st of every other year of this licence (coincident with the years in which an internal audit is conducted), OPG shall submit an annual Confidential Audit Report to the Board. The report shall include:

   a. A review of the design, implementation, completeness and security of the Ring-Fence plan by OPG's internal audit group;

   b. A list of all the violations of the Ring-Fence plan with an explanation as to the type of violation, the employee's position and department or group, and whether the incident represents a repeat violation by a given employee;

   c. Recommendations regarding corrective action where the Ring-Fence plan has been violated;

   d. A list of the number of employees that have moved outside the Ring-Fence to a new position in OPG (whether the position is permanent or temporary) The Report shall identify the old position and department or group that was in the Ring-Fence plan, and the new position and department or group in which the employee now works.

6. Prior to December 31st of every other year of this licence (coincident with the years in which an internal audit is conducted), OPG shall submit an annual Public Audit Report to the Board for the public record. The report shall include the above findings from the Confidential Audit Report, however, the report shall be redacted to remove personal information and any other information that the Board agrees may be redacted under its confidential filing guidelines.

7. The Contract for Differences for Forced Outages agreement between OPG and BP LP shall not be renewed at its expiry on the second anniversary of Market Opening.

PART 7 RING-FENCING OF AFFILIATE MARKET FUNCTIONS

1. The Licensee shall not share employees that are directly involved in the offer to supply electricity or ancillary services into any of the IESO-administered markets with NV LP or any subsidiary of NV LP including Portlands Energy Centre L.P. and Brighton Beach Power L.P. This shall not preclude (i) the sharing between the Licensee and NV LP or a subsidiary of NV LP of employees in “shared corporate services” as defined in the Affiliate Relationships Code for Electricity Distributors and Transmitters, or (ii) employees of the Licensee from serving as a director of NV LP or a subsidiary of NV LP, provided that in both cases such employees are subject to the ring-fencing plan restrictions established in accordance with this Part 7.

2. The Licensee shall implement a ring-fencing plan to ensure that (i) no competitively sensitive information (“CSI”) pertaining to the Licensee is disclosed to NV LP or any subsidiary of NV LP, (ii) employees of the Licensee that are directly involved in the offer to supply electricity or ancillary services into any of the IESO-administered markets do not obtain or have access to CSI pertaining to NV LP or any subsidiary of NV LP, and (iii) no CSI pertaining to NV LP or a subsidiary of NV LP that may be in the possession of the Licensee is used by the Licensee for any purpose relating to the offer to supply electricity or ancillary services into any of the IESO-administered markets.

3. For the purpose of paragraph 2, CSI includes information about electricity bid and offer strategy, electricity offer prices and quantities, gas procurement strategies and outage plans. CSI does not include (i) historical data or information that is no longer competitively relevant, (ii) data or information that is in the public domain, or (iii) documents from which competitive information has been redacted, deleted, aggregated or otherwise dealt with in a manner that renders the document in question not commercially sensitive. For clarity, reference to a limited partnership in this Part 7 shall include its general partner(s).

4. Notwithstanding the requirements in paragraphs 2 and 3 of this Part 7, the Licensee shall not be prohibited from sharing CSI with NV LP's subsidiary Atura H2 LP to the extent the CSI consists of information related to forward-looking outage plans that are not in the public domain (a) where the outage plans are necessary for the connection, commissioning or testing of Atura H2 LP facilities associated with its hydrogen production facility known as the "Niagara Hydrogen Centre", or (b) where OPG requires the outage to perform work on units and associated facilities at its Sir Adam Beck II Generating Station that are directly involved in the supply and delivery of electricity to the Niagara Hydrogen Centre. This exemption shall expire on August 27, 2030.

PART 8 REQUIREMENT TO OFFER INTO IESO ADMINISTERED MARKETS

1. Subject to any applicable regulatory or safety requirements and the Agreement described in paragraph 2, the Licensee shall comply with the following condition (the Must-Offer Condition):

    a. the Licensee shall, at all times during any period that the Legacy Market Rules (as defined in the Market Rules) are in force, offer all available generating capacity into the IESO administered markets for Operating Reserve, the Day Ahead Commitment Process and real-time Energy; and

    b. the Licensee shall, at all times during any period that the Renewed Market Rules (as defined in the Market Rules) are in force, offer all available generating capacity into the IESO administered markets for Energy and Operating Reserve, including the Day-Ahead Market and the Real-Time Market.

2. The Licensee shall enter into an Agreement with the IESO for the purpose of assessing ongoing compliance with the Must-Offer Condition established in paragraph 1. The Agreement shall

include any necessary detail or description of the Must-Offer Condition, the criteria that will be used to assess whether the Licensee has complied with the condition, and the right for the IESO to audit the Licensee where the IESO identifies based on the criteria that the Licensee may not have complied with the condition. The Licensee shall file the Agreement for approval of the OEB. Once the Agreement is approved, any material changes to the Agreement shall be filed with the OEB for approval.

SCHEDULE A

TERMS AND CONDITIONS OF SETTLEMENT AGREEMENT BETWEEN IESO AND OPGI

For these purposes, terms with initial capitals not otherwise defined herein shall have the meanings ascribed thereto in paragraph 1 of Part 3 of the licence conditions of OPGI or the IESO's Market Rules, as applicable.

OPGI will be required to rebate annually to the IESO. As soon as practicable and preferably within 15 days following the final settlement of transactions which occurred during each Settlement Period, the IESO shall calculate the Rebate and notify OPGI of such calculated Rebate.

If OPGI agrees with the IESO's calculation then, within 30 days of being notified, OPGI will be required to pay such Rebate, if any, to the IESO. If OPGI does not agree with the IESO's calculation and the parties can agree within a further 30 days on a revised Rebate, then, within 30 days of so agreeing, OPGI will be required to pay the agreed revised Rebate, if any, to the IESO. If OPGI does not agree with the IESO's calculation and the parties cannot agree on a revised Rebate within such further 30 day period, then the matter shall be finally determined by arbitration by the Dispute Resolution Panel of the IESO, and, within 30 days of such final determination, OPGI will be required to pay the finally determined Rebate, if any, to the IESO. The initially calculated, agreed revised, or finally determined Rebate, as applicable, shall be the Rebate in respect of such Settlement Period for all purposes hereof. Unless the Rebate is paid within 30 days of the IESO notifying OPGI, interest at the Prime Rate, calculated and accrued daily, from such 30th day until the date of payment to the IESO will in all cases be added to (and based upon) the final Rebate owing.

Following payment of the Rebate by OPGI to the IESO, the IESO shall pay or apply the Rebate as follows:

(a) Where the Rebate is $10 million or more, exclusive of any amounts representing interest or GST, the IESO shall pay the Rebate, including GST and interest, to all persons who were Market Participants in Ontario during the Settlement Period and who pursuant to the Market Rules had attributed to them during the Settlement Period an allocated quantity of energy withdrawn at a Delivery Point (the "Ontario Payees"). The IESO shall pay the Rebate to Ontario Payees by the next IESO Payment Date for the real-time market following the end of the month in which the payment from OPGI is received and the IESO shall distribute payment of the Rebate to Ontario Payees in proportion to the allocated quantities of energy withdrawn at a Delivery Point which were attributed to each Ontario Payee during the Settlement Period. The IESO may, to the extent practicable, pay the Rebate to all or some Ontario Payees by applying a Rebate settlement credit to the Ontario Payees' applicable Settlement Statements; and

(b) Where the Rebate is less that $10 million, exclusive of any amounts representing interest or GST, the IESO shall retain and apply the Rebate, inclusive of any amounts representing interest or GST, to offset the IESO Administration Charge imposed on Market Participants in accordance with section 4.5, Chapter 9 of the Market Rules, during the period in which the first order of the OEB approving the IESO Administration Charge made,

    (i) pursuant to subsection 19(2) of the Electricity Act, 1998, and

    (ii) subsequent to the date on which payment of the Rebate is received by the IESO, is in effect.

    Where paragraph (a) applies, if by the date upon which the IESO is required to pay the Rebate to Ontario Payees, the IESO cannot locate an Ontario Payee, or a successor or other representative of the said Ontario Payee to whom the IESO is permitted or required by law to pay the said

Ontario Payee's share of the Rebate, the IESO shall retain the said Ontario Payee's share of the Rebate for a period of 90 days from the date upon which the Rebate is otherwise payable to all other Ontario Payees, and during this period the IESO will make commercially reasonable efforts to locate and payout the applicable share of the Rebate to the said Ontario Payee or his successor or other legal representative. If the IESO is unable to locate the said Ontario Payee or his successor or other legal representative within this 90 day period, the IESO shall retain the said Ontario Payee's share of the Rebate and apply it to the IESO Administration Charge in accordance with paragraph (b), as set out herein.

Nothing shall preclude agreements that require the purchaser to return the rebate or any portion thereof to OPGI or any other party.

The Settlement Agreement may also include the following terms:

- Definitions and Interpretation
- Notice by OPGI to IESO of Payment and Non-Payment
- Appropriate limitations of liability
- IESO shall recover its reasonable rebate administration expenses through its fees
- Appropriate indemnification provisions
- IESO to act on its own behalf and as agent for Ontario Metered Market Participants entitled to rebates to the extent of their interests, and such Metered Market Participants are entitled, provided that they give a satisfactory funded indemnity to the IESO, to enforce, by arbitration, the Settlement Agreement directly against OPGI if desired, with reasonable assistance to be provided by IESO at their expense
- IESO may assign agreement to a qualified replacement upon approval of OEB. No other assignments without consent of other party and OEB
- IESO may subcontract any duties required of it
- Fund transfer instructions, which may be changed on notice to OPGI by IESO
- Arbitration clause with Dispute Resolution Panel as arbitrator
- Recipient registrants responsible for all taxes, if any
- Any interest earned on funds by IESO shall be paid to recipient registrants similarly to other funds
- IESO not to be viewed as in conflict in any respect as a result of its participation in the Settlement Agreement
- IESO may hold funds on deposit with a Canadian financial institution or in short-term obligations of the federal or Ontario government or any Canadian financial institution
- IESO may, but shall not be obliged to, retain and refrain from distributing any funds in the event of any dispute, and may seek advice from the Dispute Resolution Panel
- Termination of agreement when OPGI Rebate obligations terminate and all funds distributed or applied. OPGI/IESO indemnification obligations and third party enforcement rights to survive termination, former indefinitely and latter for 2 years only
- IESO may rely on any document which it believes to be genuine and on the advice of counsel, if it acts in good faith
- IESO not responsible for any non-payment by OPGI
- Binding on successors and permitted assigns
- Notice clause
- Only may be amended in writing
- Governed by the laws of Ontario
- Counterparts clause
- Further assurances clause

SCHEDULE B

ADDITIONAL TERMS AND CONDITIONS OF SETTLEMENT AGREEMENT BETWEEN IESO & OPG

The following sets out the procedure for calculating, allocating and passing through the Market Power Mitigation Agreement (MPMA) Rebate. Where there is a conflict between Schedule A in the Minister's Directive dated March 24, 1999, as amended or replaced by a subsequent Ministerial Directive dated February 25, 2003 which relates to Order-in-Council 654/2003 (dated March 19, 2003), and subsequent Orders-in-Council including Order-in-Council No. 843/2003 (dated April 2, 2003), Order-In-Council No. 207/2005 (dated February 16, 2005), Order-in-Council No. 1909/2005 (dated December 7, 2005), Order-in-Council No. 141/2006 (dated February 3rd, 2006), Order-in-Council No. 1062/2006 (dated May 17, 2006) and this Schedule B, then this Schedule B prevails.

For the First Settlement Period (May 1, 2002 to April 30, 2003)

1) The first MPMA Rebate is to be paid out for the 9-month period ending January 31, 2003. This is the amount, as calculated by the IESO and agreed to by OPG, that OPG is required to rebate for the nine month period, based on OPG's MPMA license conditions, less the interim payment already made by OPG of approximately $335 million and amounts relating to decontrol applications pending before the Ontario Energy Board. OPG is to pay this net amount to the IESO by May 9, 2003.

2) The second MPMA Rebate will cover the three-month period February 1, 2003 to April 30, 2003 inclusive. This is the amount, as calculated by the IESO and agreed to by OPG, that OPG is required to rebate for the three month period, based on OPG's license conditions, adjusted for any true-up required to ensure that the sum of the two rebates for the first settlement period, including the interim payment, is equal to OPG's full rebate requirements for the first Settlement Period under the OPG's MPMA license conditions. OPG is to pay this amount to the IESO by August 12, 2003.

3) The IESO will pay the pro rata share of the first MPMA Rebate and the second MPMA Rebate based on the allocated quantity of energy withdrawn during the applicable period by market participants who are receiving the fixed price under sections 79.4 and 79.5 of the *Ontario Energy Board Act*, *1998* to the Ontario Electricity Financial Corporation.

4) The IESO will pay the pro rata share of the first MPMA Rebate and the second MPMA Rebate based on the allocated quantity of energy withdrawn during the applicable period by market participants who are not distributors and are not receiving the fixed price under sections 79.4 and 79.5 of the *Ontario Energy Board Act, 1998* directly to those market participants or their assignees that are market participants where the market participants have assigned their MPMA rebate.

5) The IESO will pay to distributors who are market participants, including host distributors on behalf of their embedded distributors, the pro rata share of the first MPMA Rebate and the second MPMA Rebate based on the share of energy withdrawn during the applicable period by consumers in the distributor's or embedded distributor's respective service areas who are not receiving the fixed price under sections 79.4 and 79.5 of the *Ontario Energy Board Act, 1998* and by customers of retailers who have assigned all or a portion of their entitlement to an MPMA Rebate to that retailer. In making these calculations and payments the IESO will rely on the information reported by the distributors to the IESO as required under Appendix D. Once the IESO has received the information from the distributors and disbursed the first MPMA Rebate or the second MPMA Rebate in accordance with this Schedule B, there shall be no opportunity to

correct any such information or provide any additional information and all amounts paid shall be final and binding and not subject to any adjustment.

6) After making the payments set out in 3), 4), and 5), the IESO is to pay any remaining Rebate to the Ontario Electricity Financial Corporation to offset in whole or in part the cost of providing the fixed price of 4.3 cents per kilowatt hour to consumers who are eligible to receive, are receiving or have received the fixed price under sections 79.4 and 79.5 of the *Ontario Energy Board Act, 1998*. Any amounts returned to the IESO by distributors in accordance with their license conditions shall be paid over to the Ontario Electricity Financial Corporation.

For the Settlement Periods (May 1, 2003 to January 31, 2005)

7) For each Settlement Period or partial Settlement Period from May 1, 2003 to January 31, 2005, OPG is to make quarterly MPMA Rebate payments to the IESO, consistent with OPG's MPMA license conditions, as calculated by the IESO and agreed to by OPG. The IESO and OPG may agree to appropriate true-up and carry forward mechanisms provided that these are consistent with forwarding the Rebate as soon as practicable.

8) For each Settlement Period or partial Settlement Period from May 1, 2003 to January 31, 2005 the MPMA rebate payments to market participants will be calculated and determined by the IESO as follows:

$$BPPR = [(WAP – CAP) \times 0.5 \times TAQEW]$$

Where:
"Business Protection Plan Rebate" or "BPPR" is the MPMA Rebate paid out to consumers who are not receiving the fixed price under sections 79.4 and 79.5 of the *Ontario Energy Board Act, 1998*. The BPPR is to rebate half of the amount by which the weighted average commodity price of electricity exceeds 3.8 cents per kilowatt- hour.

"Weighted Average Price" or "WAP" is the average Hourly Ontario Electricity Price weighted by load over the Settlement Period as determined by the IESO.

"Total Allocated Quantity of Energy Withdrawn" or "TAQEW" is the total electricity withdrawn from the IESO-controlled grid for use in Ontario during the Settlement Period.

9) The IESO will make quarterly MPMA payments to market participants based on the applicable Settlement Period to the end of the previous quarter, and taking into account all prior quarterly MPMA payments made with respect to the applicable Settlement Period. The IESO will adjust the payment for the final quarter of each Settlement Period to ensure that the sum of the quarterly MPMA payments for the applicable Settlement Period does not exceed the BPPR entitlement for the Settlement Period. If there is an overpayment of quarterly payments over a Settlement Period based on the BPPR entitlement for that Settlement Period, any such overpayment can be carried over to successive Settlement Periods to be offset against future payments.

10) The IESO will pay the pro rata share of the BPPR based on the allocated quantity of energy withdrawn for the applicable period by market participants who are receiving the fixed price under sections 79.4 and 79.5 of the *Ontario Energy Board Act*, *1998* to the Ontario Electricity Financial Corporation.

11) The IESO will pay the pro rata share of the BPPR based on the allocated quantity of energy withdrawn for the applicable period by market participants who are not distributors and are not receiving the fixed price under sections 79.4 and 79.5 of the *Ontario Energy Board Act, 1998*

directly to those market participants or their assignees that are market participants where the market participants have assigned their MPMA Rebate.

12) The IESO will pay to distributors who are market participants, including host distributors on behalf of their embedded distributors, the pro rata share of the BPPR based on the share of energy withdrawn for the applicable period by consumers in the distributor's or embedded distributor's respective service areas who are not receiving the fixed price under sections 79.4 and 79.5 of the *Ontario Energy Board Act, 1998* for the MPMA Rebate and by customers of retailers who have assigned all or a portion of their entitlement to an MPMA Rebate to that retailer. In making these calculations and payments the IESO will rely on the information reported by the distributors to the IESO as required under Appendix D. Once the IESO has received the information from the distributors and disbursed the BPPR for that quarter in accordance with this Schedule B, there shall be no opportunity to correct any such information or provide any additional information and all amounts paid shall be final and binding and not subject to any adjustment.

13) For the quarterly periods from May 1, 2003 to January 31, 2005, after making the payments set out in 10), 11), and 12), the IESO is to pay any remaining Rebate to the Ontario Electricity Financial Corporation to offset in whole or in part the cost of providing the prices established under sections 79.4 and 79.5 of the *Ontario Energy Board Act, 1998* to consumers who are eligible to receive the prices established under sections 79.4 and 79.5 of the *Ontario Energy Board Act, 1998.* Any amounts returned to the IESO by distributors in accordance with their license conditions shall be paid over to the Ontario Electricity Financial Corporation.

For the Payment for the Period (February 1, 2005 to March 31, 2005)

14) For the Payment for the Period from February 1, 2005 to March 31, 2005, OPG is to make an MPMA Rebate payment to the IESO, consistent with OPG's MPMA license conditions, as calculated by the IESO and agreed to by OPG. The IESO and OPG may agree to appropriate true-up and carry forward mechanisms provided that these are consistent with forwarding the Rebate as soon as practicable.

15) For the Payment for the Period from February 1, 2005 to March 31, 2005 the MPMA rebate payments to market participants will be calculated and determined by the IESO as follows:

$$BPPR = [(WAP - CAP) \times 0.5 \times TAQEW]$$

Where:
"Business Protection Plan Rebate" or "BPPR" is the MPMA Rebate paid out to consumers who are not receiving the fixed price under sections 79.4, 79.5, and 79.16 of the *Ontario Energy Board Act, 1998*. The BPPR is to rebate half of the amount by which the weighted average commodity price of electricity exceeds 3.8 cents per kilowatt hour.

"Weighted Average Price" or "WAP" is the average Hourly Ontario Electricity Price weighted by load over the Settlement Period as determined by the IESO.
"Total Allocated Quantity of Energy Withdrawn" or "TAQEW" is the total electricity withdrawn from the IESO-controlled grid for use in Ontario during the Settlement Period.

16) The IESO will make the MPMA payment to market participants for the two month period ending March 31, 2005 taking into account all prior MPMA payments made in that Settlement Period.

17) The IESO will pay the pro rata share of the BPPR based on the allocated quantity of energy withdrawn for the applicable period by market participants who are receiving the prices established under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act*, *1998* to the Ontario Electricity Financial Corporation.

18) The IESO will pay the pro rata share of the BPPR based on the allocated quantity of energy withdrawn for the applicable period by market participants who are not distributors and are not receiving the prices established under sections 79.4, 79.5, and 79.16 of the *Ontario Energy Board Act, 1998* directly to those market participants or their assignees that are market participants where the market participants have assigned their MPMA Rebate.

19) The IESO will pay to distributors who are market participants, including host distributors on behalf of their embedded distributors, the pro rata share of the BPPR based on the share of energy withdrawn for the applicable period by consumers in the distributor's or embedded distributor's respective service areas who are not receiving the prices established under sections 79.4, 79.5, and 79.16 of the *Ontario Energy Board, Act 1998* for the MPMA Rebate and by customers of retailers who have assigned all or a portion of their entitlement to an MPMA Rebate to that retailer. In making these calculations and payments the IESO will rely on the information reported by the distributors to the IESO as required under Appendix D. Once the IESO has received the information from the distributors and disbursed the BPPR for that quarter in accordance with this Schedule B, there shall be no opportunity to correct any such information or provide any additional information and all amounts paid shall be final and binding and not subject to any adjustment.

20) After making the payments set out in 17), 18), and 19), the IESO is to pay any remaining Rebate to the Ontario Electricity Financial Corporation to offset in whole or in part the cost of providing the prices established under sections 79.4, 79.5, and 79.16 of the *Ontario Energy Board Act, 1998* to consumers who are eligible to receive the prices established under sections 79.4, 79.5, and 79.16 of the *Ontario Energy Board Act, 1998.* Any amounts returned to the IESO by distributors in accordance with their license conditions shall be paid over to the Ontario Electricity Financial Corporation.

Replacement of the MPMA Rebate With A New Payment for the Period (April 1, 2005 to December 31, 2005)

21) For the Payment for the Period from April 1, 2005 to December 31, 2005, OPG is to make a single payment to the IESO, calculated as follows:

    Payment = Sum over all hours [(HOEP - $47) x (ONPA (output) x 0.85)]

    Where:
    ONPA or OPG's Non-Prescribed Assets are those generation assets operated and controlled by Ontario Power Generation, excluding Lennox Generating Station, that are not prescribed assets under section 78.1 of the *Ontario Energy Board Act, 1998* as amended by the *Electricity Restructuring Act, 2004*.

    HOEP is the Hourly Ontario Energy Price as determined by the IESO.

    ONPA (output) is the generation output from OPG's Non-Prescribed Assets generation assets over each hour of the period adjusted to take account of volumes sold through Transitional Rate Option contracts and forward contracts in effect as of January 1, 2005.

22) For the Payment for the Period from April 1, 2005 to December 31, 2005 the single payment to market participants will be equal to the payment calculated in 21) above.

23) The IESO will pay the pro rata share of the Payment based on the allocated quantity of energy withdrawn for the applicable period by market participants who are receiving the prices established under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act*, *1998* to the

Ontario Power Authority to be applied to the variance account established under section 25.33 (5) of the *Electricity Act, 1998* as amended by the *Electricity Restructuring Act, 2004.*

24) The IESO will pay the pro rata share of the Payment based on the allocated quantity of energy withdrawn for the applicable period by market participants who are not distributors and are not receiving the prices established under sections 79.4, 79.5, and 79.16 of the *Ontario Energy Board Act, 1998* directly to those market participants or their assignees that are market participants where the market participants have assigned their Payment.

25) The IESO will pay to distributors who are market participants, including host distributors on behalf of their embedded distributors, the pro rata share of the Payment based on the share of energy withdrawn for the applicable period by consumers in the distributor's or embedded distributor's respective service areas who are not receiving the prices established under sections 79.4, 79.5, and 79.16 of the *Ontario Energy Board Act, 1998* for the Payment and by customers of retailers who have assigned all or a portion of their entitlement to a Payment to that retailer. In making these calculations and payments the IESO will rely on the information reported by the distributors to the IESO as required under Appendix D. Once the IESO has received the information from the distributors and disbursed the Payment for the period in accordance with this Schedule B, there shall be no opportunity to correct any such information or provide any additional information and all amounts paid shall be final and binding and not subject to any adjustment.

26) After making the payments set out in 23), 24), and 25), the IESO is to pay any remaining amount of the Payment to the Ontario Power Authority to be applied to the variance account established under section 25.33 (5) of the *Electricity Act, 1998* as amended by the *Electricity Restructuring Act, 2004*.

27) With respect to its non-prescribed generating facilities, OPG shall maximize their value to the people of Ontario by operating those facilities in response to the price signals of the IESO-administered markets. OPG's conduct in the IESO-administered markets under this direction is subject to review by the Market Surveillance Panel of the Ontario Energy Board.

Replacement of the MPMA Rebate With A New Payment for the Period (January 1, 2006 to April 30, 2006)

28) For the Payment for the Period from January 1, 2006 to April 30, 2006, OPG is to make a single payment to the IESO, calculated as follows:

    Payment = Sum over all hours [[(HOEP - $47) x (ONPA (output) x 0.85)] + [(PA (price) - $52) x (PA (amount))]]

    Where:
    ONPA or OPG's Non-Prescribed Assets are those generation assets operated and controlled by Ontario Power Generation, excluding Lennox Generating Station, that are not prescribed assets under section 78.1 of the *Ontario Energy Board Act, 1998* as amended by the *Electricity Restructuring Act, 2004*.

    HOEP is the Hourly Ontario Energy Price as determined by the IESO.

    ONPA (output) is the generation output from OPG's Non-Prescribed Assets generation assets over each hour of the period adjusted to take account of volumes sold through Transitional Rate Option contracts and forward contracts in effect as of January 1, 2005 and volumes sold through the Pilot Auction administered by the Ontario Power Authority in the first half of 2006 with sales volumes commencing on April 1, 2006.

PA is the Pilot Auction administered by the Ontario Power Authority in the first half of 2006, which includes a limited amount of output from OPG's non-prescribed assets, with sales to commence on April 1, 2006.

PA (amount) is the hourly volume in MWh of OPG non-prescribed assets output sold through the Pilot Auction administered by the Ontario Power Authority in the first half of 2006 with sales commencing on April 1, 2006.

PA (price) is the weighted average auction price in $/ MWh realized in each hour of the Period for the output of the limited amount of OPG non-prescribed assets output volume sold through the Pilot Auction administered by the Ontario Power Authority in the first half of 2006 with sales volumes commencing on April 1, 2006.

29) For the Payment for the Period from January 1, 2006 to April 30, 2006 the single Payment to market participants will be equal to the Payment calculated in 28) above.

30) The IESO will pay the pro rata share of the Payment based on the allocated quantity of energy withdrawn for the applicable period by market participants who are receiving the prices established under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act*, *1998* to the Ontario Power Authority to be applied to the variance account established under section 25.33 (5) of the *Electricity Act, 1998* as amended by the *Electricity Restructuring Act, 2004.*

31) The IESO will pay the pro rata share of the Payment based on the allocated quantity of energy withdrawn for the applicable period by market participants who are not distributors and are not receiving the prices established under sections 79.4, 79.5, and 79.16 of the *Ontario Energy Board Act, 1998* directly to those market participants or their assignees that are market participants where the market participants have assigned their Payment.

32) The IESO will pay to distributors who are market participants, including host distributors on behalf of their embedded distributors, the pro rata share of the Payment based on the share of energy withdrawn for the applicable period by consumers in the distributor's or embedded distributor's respective service areas who are not receiving the prices established under sections 79.4, 79.5, and 79.16 of the *Ontario Energy Board Act, 1998* for the Payment and by customers of retailers who have assigned all or a portion of their entitlement to a Payment to that retailer. In making these calculations and payments the IESO will rely on the information reported by the distributors to the IESO as required under Appendix D. Once the IESO has received the information from the distributors and disbursed the Payment for the period in accordance with this Schedule B, there shall be no opportunity to correct any such information or provide any additional information and all amounts paid shall be final and binding and not subject to any adjustment.

33) After making the payments set out in 30), 31), and 32), the IESO is to pay any remaining amount of the Payment to the Ontario Power Authority to be applied to the variance account established under section 25.33 (5) of the *Electricity Act, 1998* as amended by the *Electricity Restructuring Act, 2004*.

34) With respect to its non-prescribed generating facilities, OPG shall maximize their value to the people of Ontario by operating those facilities in response to the price signals of the IESO-administered markets. OPG's conduct in the IESO-administered markets under this direction is subject to review by the Market Surveillance Panel of the Ontario Energy Board.

OPG Rebate for the Period (May 1, 2006 to April 30, 2009)

35) For the Period from May 1, 2006 to April 30, 2009, OPG is to make quarterly Payments to the IESO, as calculated by the IESO and agreed to by OPG as follows:

Payment = Sum over all hours [(HOEP – ORL) x (ONPAO x 0.85 – PAA) + (PAP – PAORL) x PAA)]

Ontario Power Generation's quarterly payments will be based on a cumulative calculation commencing May 1, 2006 to the end of each quarter less the same cumulative calculation to the end of the previous quarter. This will continue until the final quarter ending April 30, 2009. For greater certainty, where the payment formula results in an amount owing to OPG for any quarter, no such payment will be made to OPG by the IESO and any such amount will be carried forward into subsequent quarters.

Where:

ONPA or OPG's Non-Prescribed Assets are those generation assets operated and controlled by Ontario Power Generation assets in service as of January 1, 2006, excluding Lennox Generating Station and excluding stations whose generation output is subject to a contract with the Ontario Power Authority (OPA) in the form of a hydroelectric energy supply agreement [entered into by the OPA and OPG pursuant to a ministerial direction made under section 25.32 of the *Electricity Act, 1998*], that are not prescribed assets under section 78.1 of the *Ontario Energy Board Act, 1998* as amended by the *Electricity Restructuring Act, 2004*.

HOEP is the Hourly Ontario Energy Price as determined by the IESO.

ONPAO is the generation output from OPG's Non-Prescribed Assets, over each hour of the quarter adjusted to take account of volumes sold through forward contracts in effect as of January 1, 2005. For greater certainty, any output from ONPA resulting from fuel conversion by Ontario Power Generation in ONPA, or incremental output from ONPA resulting from refurbishment or expansion, or is subject to a contract with the OPA in the form of a hydroelectric energy supply agreement, [entered into by the OPA and OPG pursuant to a ministerial direction made under section 25.32 of the *Electricity Act, 1998*] is to be excluded from ONPAO.

Incremental Output is defined as:
generation output x (new total installed capacity – installed capacity as of January 1, 2006) / new total installed capacity.
ORL is the Ontario Power Generation Revenue limit.
For the period May 1, 2006 to April 30, 2007 ORL is equal to $46/ MWh.
For the period May 1, 2007 to April 30, 2008 ORL is equal to $47/ MWh.
For the period May 1, 2008 to April 30, 2009 ORL is equal to $48/ MWh.

PA is the Pilot Auction administered by the Ontario Power Authority in the first half of 2006.

PAA is the volume in MWh over each hour in the quarter that is sold by Ontario Power Generation through the PA.

PAORL is the Pilot Auction Ontario Power Generation Revenue limit.
For the period May 1, 2006 to April 30, 2007 PAORL is equal to $51/ MWh.
For the period May 1, 2007 to April 30, 2008 PAORL is equal to $52/ MWh.
For the period May 1, 2008 to April 30, 2009 PAORL is equal to $53/ MWh.

PAP is the weighted average auction price in $/ MWh over each hour of the quarter realized for the PAA by Ontario Power Generation.

36) For the Payment for the Period from May 1, 2006 to April 30, 2009 quarterly payments made by the IESO to market participants will be equal to the quarterly Payment calculated in 35) above. In the event of any quarterly Payment calculated in 35) above being negative, no quarterly payment will be made by the IESO to market participants.

37) The IESO will pay the pro rata share of the Payment based on the allocated quantity of energy withdrawn for the applicable quarter by market participants who are receiving the prices established under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act*, *1998* to the Ontario Power Authority to be applied to the variance account established under section 25.33 (5) of the *Electricity Act, 1998* as amended by the *Electricity Restructuring Act, 2004.*

38) The IESO will pay the pro rata share of the Payment based on the allocated quantity of energy withdrawn for the applicable quarter by market participants who are not distributors and are not receiving the prices established under sections 79.4, 79.5, and 79.16 of the *Ontario Energy Board Act, 1998* directly to those market participants.

39) The IESO will pay to distributors who are market participants, including host distributors on behalf of their embedded distributors, the pro rata share of the Payment based on the share of energy withdrawn for the applicable quarter by consumers in the distributor's or embedded distributor's respective service areas who are not receiving the prices established under sections 79.4, 79.5, and 79.16 of the *Ontario Energy Board Act, 1998* for the Payment. In making these calculations and payments the IESO will rely on the information reported by the distributors to the IESO as required under Appendix D. Once the IESO has received the information from the distributors and disbursed the Payment for the quarter in accordance with this Schedule B, there shall be no opportunity to correct any such information or provide any additional information and all amounts paid shall be final and binding and not subject to any adjustment.

40) After making the payments set out in 37), 38), and 39), the IESO is to pay any remaining amount of the Payment to the Ontario Power Authority to be applied to the variance account established under section 25.33 (5) of the *Electricity Act, 1998* as amended by the *Electricity Restructuring Act, 2004*.

41) With respect to its non-prescribed generating facilities, OPG shall maximize their value to the people of Ontario by operating those facilities in response to the price signals of the IESO-administered markets. OPG's conduct in the IESO-administered markets under this direction is subject to review by the Market Surveillance Panel of the Ontario Energy Board.

SCHEDULE 1 LIST OF LICENSED GENERATION FACILITIES

The Licence authorizes the Licensee only in respect to the following:

1. The ownership and operation of Darlington Nuclear Generating Station, located at Bowmanville, Ontario.
2. The ownership and operation of Pickering Nuclear Generating Station A, located at Pickering, Ontario.
3. The ownership and operation of Pickering Nuclear Generating Station B, located at Pickering, Ontario.
4. The ownership and operation of Atikokan, located at Atikokan, Ontario.
5. The ownership and operation of Lennox, located at Greater Napanee, Ontario.
6. The ownership and operation of Abitibi Canyon, located at Smooth Rock Falls, Ontario.
7. The ownership and operation of Aguasabon, located at Thunder Bay, Ontario.
8. The ownership and operation of Alexander, located at Nipigon, Ontario.
9. The ownership and operation of Arnprior, located at Arnprior, Ontario.
10. The ownership and operation of Auburn, located at Peterborough, Ontario.
11. The ownership and operation of Barrett Chute, located at Renfrew, Ontario.
12. The ownership and operation of Big Chute, located at Coldwater, Ontario.
13. The ownership and operation of Big Eddy, located at Bala, Ontario.
14. The ownership and operation of Bingham Chute, located at Powassan, Ontario.
15. The ownership and operation of Calabogie, located at Renfrew, Ontario.
16. The ownership and operation of Cameron Falls, located at Nipigon, Ontario.
17. The ownership and operation of Caribou Falls, located at Kenora, Ontario.
18. The ownership and operation of Chats Falls (Units 2-5), located at Ottawa, Ontario.
19. The ownership and operation of Chenaux, located at Renfrew, Ontario.
20. The ownership and operation of Chute, located at Elk Lake, Ontario.
21. The ownership and operation of Coniston, located at Coniston, Ontario.
22. The ownership and operation of Crystal Falls, located at Sturgeon Falls, Ontario.
23. The ownership and operation of DeCew Falls I, located at St. Catherines, Ontario.

24. The ownership and operation of DeCew Falls II, located at St. Catherines, Ontario.
25. The ownership and operation of Des Joachims, located at Deep River, Ontario.
26. The ownership and operation of Ear Falls, located at Ear Falls, Ontario.
27. The ownership and operation of Elliot Chute, located at Powassan, Ontario.
28. The ownership and operation of Eugenia Falls, located at Meaford, Ontario.
29. The ownership and operation of Frankford, located at Frankford, Ontario.
30. The ownership and operation of Hagues Reach, located at Campbellford, Ontario.
31. The ownership and operation of Hanna Chute, located at Bracebridge, Ontario.
32. The ownership and operation of Healey Falls, located at Campbellford, Ontario.
33. The ownership and operation of High Falls, located at Perth, Ontario.
34. The ownership and operation of Kakabeka Falls, located at Thunder Bay, Ontario.
35. The ownership and operation of Lac Seul, located at Ear Falls, Ontario.
36. The ownership and operation of Lakefield, located at Lakefield, Ontario.
37. The ownership and operation of Lower Notch, located at North Cobalt, Ontario.
38. The ownership and operation of Manitou Falls, located at Ear Falls, Ontario.
39. The ownership and operation of Matabitchuan, located at North Cobalt, Ontario.
40. The ownership and operation of McVittie, located at Sudbury, Ontario.
41. The ownership and operation of Merrickville, located at Smith Falls, Ontario.
42. The ownership and operation of Meyersberg, located at Campbellford, Ontario.
43. The ownership and operation of Mountain Chute, located at Renfrew, Ontario.
44. The ownership and operation of Nipissing, located at Nipissing, Ontario.
45. The ownership and operation of Otter Rapids, located at Kapuskasing, Ontario.
46. The ownership and operation of Otto Holden, located at Mattawa, Ontario.
47. The ownership and operation of Pine Portage, located at Nipigon, Ontario.
48. The ownership and operation of Robert H. Saunders, located at Cornwall, Ontario.
49. The ownership and operation of Ragged Rapids, located at Bala, Ontario.
50. The ownership and operation of Ranney Falls, located at Campbellford, Ontario.

51. The ownership and operation of Seymour, located at Campbellford, Ontario.

52. The ownership and operation of Sidney, located at Trenton, Ontario.

53. The ownership and operation of Sills Island, located at Frankford, Ontario.

54. The ownership and operation of Silver Falls, located at Thunder Bay, Ontario.

55. The ownership and operation of Sir Adam Beck I, located at Queenston, Ontario.

56. The ownership and operation of Sir Adam Beck II, located at Queenston, Ontario.

57. The ownership and operation of Sir Adam Beck PGS, located at Queenston, Ontario.

58. The ownership and operation of South Falls, located at Bracebridge, Ontario.

59. The ownership and operation of Stewartville, located at Arnprior, Ontario.

60. The ownership and operation of Stinson, located at Sudbury, Ontario.

61. The ownership and operation of Trethewey Falls, located at Bracebridge, Ontario.

62. The ownership and operation of Whitedog Falls, located at Kenora, Ontario.

63. The ownership of Bruce Nuclear Generating Station A[1], located at Tiverton, Ontario.

64. The ownership of Bruce Nuclear Generating Station B[2], located at Tiverton, Ontario.

65. The operation of Chats Falls (Units 6-9), located at Ottawa, Ontario.

66. The operation of Harmon (LMELP)[3], located at Kapuskasing, Ontario.

67. The operation of Kipling (LMELP)[4], located at Kapuskasing, Ontario.

68. The operation of Little Long (LMELP)[5], located at Kapuskasing, Ontario.

[1] Operated by Bruce Power Inc. under the authority of its electricity generation licence EG-2018-0272.
[2] Operated by Bruce Power Inc. under the authority of its electricity generation licence EG-2018-0272.
[3] Owned by Lower Mattagami Energy Limited Partnership under the authority of its electricity generation licence EG-2010-0254.
[4] Owned by Lower Mattagami Energy Limited Partnership under the authority of its electricity generation licence EG-2010-0254.
[5] Owned by Lower Mattagami Energy Limited Partnership under the authority of its electricity generation licence EG-2010-0254.

SCHEDULE 2 AUTHORIZED TRADE NAMES

1. None

Canadian Nuclear Safety Commission
Commission canadienne de sûreté nucléaire

Regulatory Document

RD–360

Life Extension of Nuclear Power Plants

February 2008

Canada

CNSC REGULATORY DOCUMENTS

The Canadian Nuclear Safety Commission (CNSC) develops regulatory documents under the authority of paragraphs 9(b) and 21(1)(*e*) of the *Nuclear Safety and Control Act* (NSCA).

Regulatory documents provide clarifications and additional details to the requirements set out in the NSCA and the regulations made under the NSCA, and are an integral part of the regulatory framework for nuclear activities in Canada.

Each regulatory document aims at disseminating objective regulatory information to stakeholders, including licensees, applicants, public interest groups and the public on a particular topic to promote consistency in the interpretation and implementation of regulatory requirements.

A CNSC regulatory document or any part thereof becomes a legal requirement when it is referenced in a licence or any other legally enforceable instrument.

Regulatory Document

RD–360

LIFE EXTENSION OF NUCLEAR POWER PLANTS

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Document availability

The document can be viewed on the CNSC web site at www.nuclearsafety.gc.ca. Copies may be ordered in English or French using the contact information below:

Public Affairs and Media Relations Division
Canadian Nuclear Safety Commission
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Facsimile: 613-992-2915
E-mail: info@cnsc-ccsn.gc.ca

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LIFE EXTENSION OF NUCLEAR POWER PLANTS

1.0 PURPOSE

This regulatory document is one of a suite of regulatory documents that cover the life cycle of Canadian nuclear power plants from siting and design to operation and decommissioning. The purpose of this regulatory document is to inform licensees about the steps and phases to consider when undertaking a project to extend the life of a nuclear power plant (NPP).

2.0 SCOPE

This regulatory document addresses:

1. Key elements to consider when establishing the scope of the life extension project; and
2. Considerations to be taken into account in planning and executing a life extension project.

3.0 RELEVANT LEGISLATION

The following provisions of the *Nuclear Safety and Control Act* (NSCA) and related regulations are relevant to this regulatory document:

1. Section 3 of the NSCA provides for, “the limitation, to a reasonable level and in a manner that is consistent with Canada’s international obligations, of the risks to national security, the health and safety of persons and the environment that are associated with the development, production and use of nuclear energy…”;
2. Section 9 of the NSCA provides the objects of the Commission, which are, “to regulate the development, production and use of nuclear energy and the production, possession and use of nuclear substances, prescribed equipment and prescribed information…”;
3. Subsection 24(4) of the NSCA stipulates that, “No licence may be issued, renewed, amended or replaced unless, in the opinion of the Commission, the applicant
   (*a*) is qualified to carry on the activity that the licence will authorize the licensee to carry on; and
   (b) will, in carrying on that activity, make adequate provision for the protection of the environment, the health and safety of persons and the maintenance of national security and measures required to implement international obligations to which Canada has agreed”;
4. Subsection 24(5) of the NSCA provides that, “a licence may contain any term or condition that the Commission considers necessary for the purposes of the Act…”;

5. Section 3 of the *General Nuclear Safety and Control Regulations* contains the general licence application requirements;
6. Paragraph 12(1)(*c*) of the *General Nuclear Safety and Control Regulations* says that every licensee shall, “take all reasonable precautions to protect the environment and the health and safety of persons and to maintain security”;
7. Paragraph 12(1)(*f*) of the *General Nuclear Safety and Control Regulations* says that every licensee shall, “take all reasonable precautions to control the release of radioactive nuclear substances or hazardous substances within the site of the licensed activity and into the environment as a result of the licensed activity”;
8. Paragraph 12(1)(*i*) of the *General Nuclear Safety and Control Regulations* stipulates that every licensee shall, “take all necessary measures to facilitate Canada's compliance with any applicable safeguards agreement”;
9. Section 3 of the *Class I Nuclear Facilities Regulations* outlines the general licence application requirements specific to nuclear power plants; and
10. Section 6 of the *Class I Nuclear Facilities Regulations* stipulates the information that is required in an application for a nuclear power plant operating licence.

Regulations associated with the *Canadian Environmental Assessment Act* will also be applicable to a life extension project. Other relevant legislation is listed in the Associated Documents section at the end of this regulatory document.

4.0 INTRODUCTION

Nuclear power plants in Canada are subject to the ongoing regulatory oversight of the Canadian Nuclear Safety Commission (CNSC, the Commission), including periodic licence renewal. However, the NPP licensee may choose, for the purpose of long-term operation, to implement a life extension project. Continued operation of the NPP is largely dependent on the work that will be required for long term safe operation of the plant.

A life extension project may involve the replacement or refurbishment of major components, or substantial modifications to the plant, or both. As such, these projects represent a commitment to long-term, continued operation of the facility. In keeping with the objectives of the NSCA, the Commission is mandated to ensure that facility operation continues to pose no unreasonable risk to health, safety, security, or the environment, and will conform to Canada’s international obligations.

The Commission therefore considers it to be in the public interest that licensees address modern high level safety goals, and meet applicable regulatory requirements for safe and secure long-term operation. To this end, NPP licences are amended to introduce specific licence conditions for the regulatory control of life extension projects. The licensee is expected to adhere to the requirements of the NSCA and the *Canadian Environmental Assessment Act*, and all associated regulations, and to all licence conditions throughout the life extension project and subsequent reactor operation.

Approval for return-to-service is contingent upon demonstration by the licensee that all licence conditions have been met.

In keeping with its regulatory mandate, the Commission expects the licensee to demonstrate that the following objectives are met for any life extension project:

1. The technical scope of the project is adequately determined through a Integrated Implementation Plan that takes into account the results of an environmental assessment (EA), where required, and an Integrated Safety Review (ISR);
2. Programs and processes that take into account the special considerations of the project are established; and
3. The project is appropriately planned and executed.

5.0 PROJECT INITIATION

The licensee formally advises the Commission of the intention to conduct a life extension project, and submits a project description with this notification. The project description indicates the licensee’s initial understanding of the project, and includes:

1. Definition of project scope and objectives;
2. Status of current plant design and operation;
3. Project components and structures (such as permanent and temporary structures, infrastructure, construction equipment, etc.);
4. Expected project activities (such as operational phases, timing and scheduling of each phase, etc.);
5. Site information (such as location, environmental features, and land use);
6. Waste issues; and
7. Anticipated milestones.

The project description forms the basis of the EA, and is also used as a point of reference for the project.

Information to assist the licensee in developing the project description is provided in the Canadian Environmental Assessment Agency’s publication, *Preparing Project Descriptions under the Canadian Environmental Assessment Act*.

6.0 ESTABLISHING THE INTEGRATED IMPLEMENTATION PLAN

Once the licensee decides to undertake a life extension project, the licensee systematically identifies and addresses all environmental and safety concerns, and integrates them into an *Integrated Implementation Plan*. To do this, the licensee:

1. Participates in the environmental assessment (EA) process (Section 6.1, below);
2. Carries out an Integrated Safety Review (Section 6.2, below); and
3. Applies the results of these assessments to establish the Integrated Implementation Plan (Section 6.3.2, below).

Since the EA and ISR may provide information relevant to each other, these assessments are done in parallel where practicable.

6.1 Environmental Assessment

In accordance with the *Canadian Environmental Assessment Act*, the life extension project may be subject to an environmental assessment. Where an EA is required, a decision that the life extension project will not have significant adverse environmental effects is needed prior to any licensing action being taken under the NSCA.

As the responsible authority for the conduct of the EA process, the Commission is responsible for determining whether an EA is required, and ensuring that the process is carried out appropriately.

6.2 Integrated Safety Review

The *Integrated Safety Review* (ISR) is a comprehensive assessment of plant design, condition, and operation. It is conducted at the time that a licensee is considering life extension of an NPP. Guidance on the ISR is found in the *Periodic Safety Review of Nuclear Power Plants – Safety Guide* (IAEA PSR Guide) published by the International Atomic Energy Agency (IAEA). It is referred to as an ISR due to its application of the *Periodic Safety Review* to the life extension project.

Performed by the licensee, the ISR involves an assessment of the current state of the plant and plant performance to determine the extent to which the plant conforms to modern standards and practices, and to identify any factors that would limit safe long-term operation. Operating experience in Canada and around the world, new knowledge from research and development activities, and advances in technology, are taken into account. This enables determination of reasonable and practical modifications that should be made to systems, structures, and components, and to management arrangements, to enhance the safety of the facility to a level approaching that of modern nuclear power plants, and to allow for long term operation.

The objectives of the ISR are to determine:

1. The extent to which the plant conforms to modern standards and practices;
2. The extent to which the licensing basis will remain valid over the proposed extended operating life;
3. The adequacy of the arrangements that are in place to maintain plant safety for long-term operation; and
4. The improvements to be implemented to resolve safety issues that have been identified.

The ISR should include:

1. Conformity reviews that confirm that the NPP meets and will continue to meet the current plant-specific licensing and design basis;
2. A review against modern standards and practices to assess the level of safety compared to that of modern NPPs (any shortcomings against these modern standards and practices are identified and their safety significance determined);
3. Any modifications that are necessary to improve the level of safety; and
4. A global assessment of plant safety for long-term operation in view of each of the ISR safety factors.

6.2.1 ISR Basis

Prior to performing the ISR, the licensee prepares an *ISR Basis Document,* which sets out the scope and methodology for the conduct of the ISR. The *ISR Basis Document* includes the following information:

1. **The proposed extended life of the facility**

   The *ISR Basis Document* clearly defines the full period of proposed extended operation. This information is also included in the project description if an EA is required.

2. **The scope of the ISR**

   The safety factors to be addressed in the ISR are listed in the IAEA's safety guide, *Periodic Safety Review of Nuclear Power Plants*. In addition, the scope of the ISR should at least address CNSC safety areas and programs (refer to Appendix A).

   The ISR should address site-specific facilities, systems, structures, and components, and any applicable site-wide issues, such as dependencies on common services. The physical status of' each unit should be considered separately for an ISR of multiple units of the same design. The adequacy of management arrangements should also be addressed.

In addition, the ISR scope should consider, as appropriate for each safety factor, all expected modes of operation (i.e., normal operation, maintenance, refuelling, shutdown, and start-up activities), to determine whether there is any potential for increased or unacceptable levels of risk.

All generic action items and station-specific actions items should be addressed in the review, with each being resolved to the extent practicable.

3. **Statement of modern standards and practices**

   The set of modern standards and practices that will be used in the review of each ISR safety factor should be provided, including the criteria for the selection of applicable standards and specifications.

   Primary consideration should be given to CNSC regulatory documents that would apply to a new facility, as well as to standards currently referenced in licences. The licensee should also consider IAEA or other appropriate modern international standards and practices.

   For each document listed, the licensee should indicate whether a high-level review, a clause-by-clause review will be performed, or whether an alternative approach will be taken. The rationale for the selected approach should be outlined.

4. **Statement of the plant licensing basis at the time of initiating the ISR**

   The licensing basis is used in conformity reviews, and also serves as the baseline in the review against the modern standards and practices.

   The licensing basis includes the CNSC regulatory framework, the documents referenced in the station-specific licence, the documents submitted by the licensee in support of the licence application, and the documents referenced therein.

5. **Process for identifying and addressing gaps**

   The licensee describes its processes for identifying and addressing gaps between current and desired plant state and performance, documenting the significance of any gaps, and prioritizing corrective actions and safety improvements.

   Non-compliance with the current licensing and design basis should be addressed immediately by the licensee. Non-compliance with modern standards and practices should be resolved to the extent practicable. An appropriate justification should be provided for any unresolved shortcomings.

The Commission reviews the *ISR Basis Document* for acceptance.

6.2.2 ISR Safety Factor Reports

The licensee considers all pertinent safety factors and prepares *ISR Safety Factor Reports* for submission to the Commission. The licensee proposes the manner in which the scope of the ISR will be addressed, and either submits reports addressing each ISR safety factor separately, or groups documentation accordingly.

The *ISR Safety Factor Reports* contain the review results, including proposed corrective actions and safety improvements, for the specific topics. The results of the conformity reviews and the comparison against modern standards and practices are also included.

6.2.3 Confirmation of the Adequacy of ISR Safety Factor Reports

The Commission reviews the *ISR Safety Factor Reports* for acceptance. The final results are incorporated in the development of the licensee's *Integrated Implementation Plan*.

6.3 Global Assessment and Integrated Implementation Plan

The licensee incorporates the results of the EA and the *ISR Safety Factor Reports* in a *Global Assessment Report*, which includes an *Integrated Implementation Plan*.

6.3.1 Global Assessment

The *Global Assessment Report* presents significant ISR results, including plant strengths, the *Integrated Implementation Plan* for corrective actions and safety improvements, and an overall risk judgment on the acceptability of continued plant operation. Interactions between safety factors, individual shortcomings, corrective actions, and safety improvements, including compensatory measures, should be considered in assessing the overall plant safety and the acceptability of continued operation. The global assessment should also show the extent to which the safety requirements of the defence-in-depth concept are fulfilled.

6.3.2 Integrated Implementation Plan

When developing the *Integrated Implementation Plan*, the licensee:

1. Identifies a list of shortcomings for each of the safety factors identified in the ISR;
2. Identifies a list of strengths with respect to fulfilling the safety requirements of the defence-in-depth concept;
3. Evaluates the safety significance and ranking of each of the shortcomings and prioritizes corrective measures. Significant safety issues should be addressed immediately. Justification for proposed exemptions from the modern standards and practices should be provided, taking the safety significance, physical practicality, and other information into account, as appropriate;
4. Develops corrective actions and safety improvements for each of the shortcomings, as far as practicable; and
5. In view of each of the ISR safety factors, evaluates the acceptability of plant operation over the next review period in an integrated assessment.

The *Integrated Implementation Plan* indicates the schedule for implementing the safety improvements, which should be completed within a reasonable time frame. The licensee provides justification for deferral of the work if the safety improvements cannot be completed during the nearest outage.

The licensee updates all station documentation such as the safety analysis report, operating and maintenance procedures, and training materials to reflect the outcomes of the ISR.

Licensees may elect to submit cost-benefit information in support of the *Integrated Implementation Plan*.

6.4 Confirmation of the Adequacy of the Global Assessment Report

The Commission reviews the licensee's *Global Assessment Report* for acceptability by assessing:

1. The completeness of the assessment;
2. The significance and ranking of identified safety issues for all assessed safety factors;
3. The adequacy of proposed corrective actions and safety improvements, or justification of proposed exemptions;
4. The adequacy of proposed implementation schedule;
5. The adequacy of the proposed measures for assuring the quality of the life extension activities; and
6. Conformance with the EA results.

The results of the Commission reviews are taken into account in the revision of the *Global Assessment Report*, including the *Integrated Implementation Plan*.

The Commission either accepts the *Global Assessment Report*, or requires changes. Upon acceptance of the *Global Assessment Report*, the licence is amended to include licence conditions to be met in the return-to-service phase of the project.

6.4.1 Integrated Implementation Plan Changes

The licensee should have a well defined process for the control of any changes to the *Integrated Implementation Plan*.

Formal approval is required for:

1. Changes in the plan associated with work that is needed to fulfil the requirements identified by the screening EA; and
2. Changes in the plan for items subject to conditions of the operating licence.

7.0 PROJECT EXECUTION

7.1 Project Execution Planning

The licensee prepares a *Project Execution Plan* that identifies what needs to be done to achieve the desired outcomes for the project. Areas that may require special attention when planning the project execution typically include:

1. Historical design issues;
2. Component obsolescence;
3. Resource requirements;
4. Use of contractors;
5. Unique or unusual plant configurations; and
6. Return to service plans.

7.2 Programs and Processes

To enable project implementation, the licensee needs acceptable programs and processes to control and execute the life extension project. These programs and processes may include consideration of such areas as:

1. Change control;
2. Commissioning;
3. Configuration management;
4. Construction;
5. Emergency preparedness;
6. Engineering design;
7. Environmental protection;
8. Fire protection;
9. Human factors;
10. Nuclear criticality safety program;
11. Occupational health and safety;
12. Outage management;
13. Training and personnel qualification;
14. Procurement;
15. Quality management;
16. Radiation protection;
17. Safeguards;
18. Safety management;
19. Security;
20. Stakeholder communication;
21. Waste management; and
22. Work control.

The licensee should refer to Commission requirements and appropriate legislation and standards when addressing these considerations, both for guidance in their development, and to determine how program outcomes will be measured.

The adequacy of programs and processes for the control of the life extension project will be assessed by the Commission.

7.3 Project Monitoring

The licensee is expected to monitor the project for progress, safety, and quality at all phases of execution. Items to be monitored may include:

1. Complete redesigns or design modifications;
2. Engineering field changes;
3. Installation rework;
4. Procedural non-compliances;
5. Plant configuration;
6. Missed completion dates;
7. Worker safety events involving injuries, near misses, unsafe practices, unplanned dose uptakes; and
8. Environmental performance.

Project monitoring includes verifying that the work has been done correctly, and may reveal the need for:

1. Creation of new programs and procedures;
2. Revision of existing programs and procedures;
3. Resource changes;
4. Revision of existing training programs or material; or
5. New training programs or material.

The licensee should assess all identified shortcomings to determine their causes and the impact of the shortcomings or their causes on other aspects of the project.

8.0 RETURN TO SERVICE

The licensee needs to establish a *Return to Service Plan* for the life extension project. Return to service involves returning the reactor, the nuclear systems, and the non-nuclear systems, back to commercial operation. Return to service includes demonstration by the licensee that all relevant licence conditions have been met and that the associated work has been done to the satisfaction of the Commission. The licensee is expected to submit design completion and construction completion assurance reports, as well as completion assurance reports for each phase of commissioning.

8.1 Commissioning Phases

Return to service is dependent on the licensee's ability to demonstrate that new and existing plant systems, structures, and components conform to the defined physical, functional, performance, safety, and control requirements, and that management arrangements have been appropriately updated.

This is accomplished through four commissioning phases:

1. **Phase A:** Focuses on ensuring that those systems required to ensure safety with fuel loaded into the reactor have been adequately commissioned. This phase must be successfully completed prior to loading fuel in the reactor;
2. **Phase B:** Focuses on ensuring the fuel is loaded into the reactor safely, and confirming that the reactor is in a suitable condition to be started up and that all prerequisites for permitting the reactor to go critical have been met. This phase must be successfully completed prior to removal of the guaranteed shutdown state (GSS);
3. **Phase C:** Focuses on confirming reactor behaviour at the stage of initial criticality and subsequent low power tests, and includes activities that cannot be done during the GSS; and
4. **Phase D:** Focuses on demonstrating reactor and systems behaviour at higher power levels, including activities that could not be carried out at the power levels in Phase C.

System baseline data from past commissioning activities should be referenced if available, or new baseline data is established. This may include inaugural and baseline inspections of existing and newly installed systems, structures, and components. In addition, the licensee is expected to define the acceptance criteria for the commissioning tests.

8.2 Milestones

Return to service is achieved through the accomplishment of numerous milestones. Milestones that might be reflected in the return to service stage of a life extension project include:

1. Loading fuel;
2. Removing the guaranteed shutdown state;
3. Heat transport operation;
4. Turbine operation;
5. Turbine synchronization to the grid;
6. Full reactor power; and
7. Specific commissioning tests.

8.3 Hold Points

The process of returning to service includes progressing to regulatory hold points. These hold points are typically aligned with commissioning phases, and may include the milestones listed above. Licence conditions are established for the administration of the hold points, which are then incorporated by the licensee in the *Return to Service Plan*.

Commission approval to remove a given hold point is contingent on licensee submission of a *Completion Assurance Document*. This document presents evidence that all project commitments scheduled for completion prior to removal of the respective hold point have been met. The *Completion Assurance Document* must be accepted by the Commission before authorization to remove the hold point can be issued.

8.4 Return to Normal Operation

Once all Commission approvals have been granted and hold points have been removed, the licensee proceeds to normal operation.

9.0 FOLLOW UP

The licensee will be expected to monitor the adequacy of plant performance and new or updated programs after return to service.

GLOSSARY

Design basis

The range of conditions and events taken into account in the design of the facility, according to established criteria, such that the facility can withstand them without exceeding authorized limits for the planned operation of safety systems.

Design life
The period specified for the safe operation of the facility, systems, structures, and components.

Environmental assessment
An assessment of the environmental effects of the project conducted in accordance with the CEAA and its regulations.

Generic action item
Unresolved safety-related issues that have been singled out by the Commission as requiring corrective actions to be taken by the licensees within a reasonable time frame.

Guaranteed shutdown state (GSS)
A set of conditions that provide sufficient guarantee that the reactor will remain in the shutdown state despite any credible failure.

Hold points
Specific milestones that are built into the commissioning plan to separate critical phases during commissioning, and to allow for regulatory review before transition between phases. Hold points further enable verification of the resolution of issues so that proceeding to the next stage will not pose unreasonable risk to health, safety, security, or the environment.

Integrated safety review (ISR)
A comprehensive assessment of plant design and operation performed in accordance with the IAEA's *Periodic Safety Review of Nuclear Power Plants – Safety Guide*.

Licensing basis
Includes the design basis, and is the set of information that demonstrates that:

1. The facility meets all applicable regulatory and safety requirements, and

2. The applicant and licensee are qualified and have made adequate provisions for safe facility operation.

Life extension
Extending the safe operating life of a nuclear power plant beyond its design life. It involves the replacement or refurbishment of major components, or substantial modifications to the plant, or both.

Modern standards
The set of high-level objectives and requirements for the siting, design, construction, commissioning, operation and decommissioning of a nuclear power plant if it were to be built at the time of the initiation of the life extension project.

Nuclear power plant
Any fission reactor installation constructed to generate electricity on a commercial scale. A nuclear power plant is a Class IA nuclear facility, as defined in the *Class I Nuclear Facilities Regulations*.

Practices

The information contained in modern industrial standards, codes, and practices directly associated with the modern standards. Guidelines should take into account operating experience and findings from technical developments (e.g., new knowledge on the cumulative effects of ageing, results of reactor physics research and development, human factors engineering, human reliability, software engineering).

Prescribed
Means prescribed by federal regulations.

Refurbishment
An activity or a set of activities aimed at restoring the condition of one or several systems to a state that is comparable to the condition of a new system.

ASSOCIATED DOCUMENTS

1. *Nuclear Safety and Control Act*, S.C. 1997, c. 9;
2. *Packaging and Transport of Nuclear Substances Regulations*, SOR/2000-208, May 2000;
3. *Radiation Protection Regulations*, SOR/2000-203, May 2000;
4. *Nuclear Security Regulations*, SOR/2000-209, May 2000;
5. *Nuclear Non-proliferation Import and Export Control Regulations*, SOR/2000-210, May 2000;
6. *Nuclear Substances and Radiation Devices Regulations*, SOR/2000-207, May 2000;
7. *Canadian Nuclear Safety Commission Rules of Procedure*, SOR/2000-211, May 2000;
8. CNSC Regulatory Standard S-99, *Reporting Requirements for Operating Nuclear Power Plants*, March 2003;
9. CNSC Regulatory Policy P-242, *Considering Cost-benefit Information*, October 2000;
10. *Canadian Nuclear Safety Commission - Guidelines for Environmental Assessment pursuant to the requirements of the Canadian Environmental Assessment Act*, Revision 2, December 2004;
11. *Nuclear Liability Act*, R.S.C., 1985, c. N-28;
12. *Canadian Environmental Assessment Act*, S.C. 1992, c. 37;
13. CEAA *Exclusion List Regulations*, SOR/94-639;
14. CEAA *Inclusion List Regulations*, SOR/94-637
15. CEAA *Comprehensive Study List Regulations*, SOR/94-638;
16. *Procedures for an Assessment by a Review Panel*, guidelines issued pursuant to the CEAA, November 1997;
17. *Preparing Project Descriptions under the Canadian Environmental Assessment Act*, Canadian Environmental Assessment Agency, August 2000;
18. *CEAA Law List Regulations*, SOR/94-636, October 1994;
19. *Canadian Environmental Protection Act*, S.C. 1999, c. 33;
20. *Nuclear Fuel Waste Act*, S.C. 2002, c. 23;

21. *Fisheries Act*, R.S.C., 1985, c. F-14;

22. *Species at Risk Act*, S.C. 2002, c. 29;

23. *Migratory Birds Convention Act*, S.C. 1994, c. 22;

24. *Canada Water Act*, R.S.C., 1985, c. C-11; and

25. *Periodic Safety Review of Nuclear Power Plants—Safety Guide*, Safety Standards Series No. NS-G-2.10, IAEA, Vienna, 2003.

APPENDIX A
CNSC SAFETY AREAS AND PROGRAMS

CNSC Safety Areas	CNSC Programs
1. Operating Performance	1. Organization and Plant Management 2. Operations 3. Occupational Health and Safety (non-radiological)
2. Performance Assurance	1. Quality Management 2. Human Factors 3. Training
3. Design and Analysis	1. Safety Analysis 2. Safety Issues 3. Design
4. Equipment Fitness for Service	1. Maintenance 2. Structural Integrity 3. Reliability 4 Equipment Qualification
5. Emergency Preparedness	1. Emergency Preparedness
6. Environmental Performance	1. Environmental Protection Systems 2. Effluent and Environmental Monitoring
7. Radiation Protection	1. Personnel Exposure 2. Plant Waste Management
8. Site Security	1. Site Security
9. Safeguards	1. Safeguards

APPENDIX B
LIFE EXTENSION PROCESS DIAGRAM