ONTARIO POWER GENERATION

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February 27, 2013

VIA RESS AND COURIER

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
P.O. Box 2319
2300 Yonge Street, 27th Floor
Toronto, Ontario M4P 1E4

Re: Request for Approval of a Reliability Must-Run Agreement for Thunder Bay GS

Dear Ms. Walli,

Ontario Power Generation Inc. ("OPG") and the Independent Electricity System Operator ("IESO") have negotiated a Reliability Must-Run ("RMR") Agreement for one unit at OPG's Thunder Bay Generating Station ("Thunder Bay GS") pursuant to Chapter 5, section 4.8, and Chapter 7, sections 2.4, 9.6 and 9.7 of the Market Rules for the Ontario electricity market. This agreement covers the period January 1, 2013 to December 31, 2013. A copy of the agreement is provided as Attachment 1.

OPG's Generation Licence (EG-2003-0104), Part 1, Paragraph 5.2, provides that any such agreement "shall be subject to approval by the OEB prior to its implementation." Pursuant to this licence condition, OPG requests OEB approval of the attached RMR Agreement for Thunder Bay GS effective January 1, 2013. The contract start date and the one year term of the agreement are based on the supply requirements as determined by the IESO in their technical assessment.

OPG requests that this application proceed by way of a written hearing given the Board's familiarity with RMR agreements. The OEB has in recent years reviewed and approved four separate RMR Agreements for OPG's Lennox GS. The Thunder Bay RMR Agreement is similar to the previously approved agreements, while including some improvements to these prior agreements. These improvements are discussed in Section 4(d) below.

1. Background

Thunder Bay GS consists of two 153 MW coal-fired units and is located in Thunder Bay, Ontario.

Thunder Bay GS generates electricity mainly during times of peak electricity demand when lower cost resources are unable to satisfy this demand. As a result, it operates for relatively few hours each year. The decline in electricity demand in north-western Ontario has resulted in a substantial decline in the production from this facility. Over the past few years, Thunder Bay GS has been unable to earn sufficient revenues in the wholesale electricity market to cover its fixed and variable operating costs. This prompted OPG to request de-registration of Thunder Bay GS.

2. Requirement for Thunder Bay GS RMR Agreement

OPG does not envision any change in market conditions that would allow Thunder Bay GS to recover its fixed and variable operating costs from the wholesale electricity market. As a result, on November 15, 2012, OPG filed a Notice of Request to De-register Thunder Bay GS with the IESO. A copy of this correspondence is provided as Attachment 2.

On January 7, 2013, the IESO responded to OPG indicating that de-registration of Thunder Bay GS would likely have an unacceptable impact on the reliability of the IESO-controlled grid, and that they were prepared to enter into negotiations for a RMR Agreement that would ensure the continued operation of at least one Thunder Bay GS unit. A copy of this correspondence is provided as Attachment 3. A copy of the IESO's Technical Assessment related to Thunder Bay GS de-registration is provided as Attachment 4.

As a result, a RMR Agreement for the period January 1, 2013 to December 31, 2013 was negotiated. This RMR Agreement was executed by OPG on February 6, 2013 and by the IESO on February 15, 2013.

As a result of the IESO's decision to include only one Thunder Bay GS unit in the RMR Agreement, OPG has taken the necessary steps to remove from service the other unit at Thunder Bay GS.

3. RMR Agreements – Relevant Market Rule Provisions

Chapter 5, section 4.8 of the market rules generally explains the need for reliability must-run resources and reliability must-run agreements. Chapter 7, section 2.4.5 provides that if a party requests de-registration of a facility and the IESO concludes that the facility is necessary for reliability of the IESO controlled grid, then the IESO and that party should commence negotiations of a reliability must-run contract under Chapter 7, sections 9.6 and 9.7. Chapter 7, section 9.6 describes the process for negotiating a reliability must-run contract while section 9.7 specifies the terms and conditions that must be addressed in a RMR contract.

4. Operation of the Thunder Bay GS RMR Agreement

The RMR Agreement is structured to allow OPG to recover the fixed costs associated with the facility from the IESO through a monthly fixed payment, and to recover its variable costs through the IESO-administered markets. The RMR Agreement ensures that OPG continues to operate the RMR facility and that it participates in Ontario’s electricity markets in a commercially reasonable manner.

(a) Performance Terms

The RMR Agreement obligates OPG to offer into the IESO-administered market the maximum available amount of energy and operating reserve from one unit at Thunder Bay GS consistent with good utility practice and in a commercially reasonable manner.

The Agreement also requires that OPG make one unit at Thunder Bay GS available whenever it is physically capable of responding to dispatch instructions, consistent with good utility practice. Finally, the Agreement provides that if future facility-related products (“Future Related Products”) can be offered into the IESO-administered markets, OPG will offer the maximum available amount of these products from one unit at Thunder Bay GS into the relevant IESO-administered markets in a commercially reasonable manner, consistent with good utility practice. OPG will also participate in other markets for Future Related Products in a commercially reasonable manner, consistent with good utility practice (RMR Agreement Section 3.3 and Schedule A, Section 1).

Schedule B of the RMR Agreement contains provisions associated with performance standards, including penalties or rewards that apply if these performance standards are missed or exceeded. The performance standards use a metric called EFOR-OP (Equivalent Forced Outage Rate-Operations) which is an indication of a generating unit’s or station’s reliability when it is required to operate. It measures the ratio of forced occurrences (outages and output derates) to “total exposure time”[1]. The reliability metric is similar to the widely used utility measure Equivalent Forced Outage Rate (EFOR) except that

[1] “Total exposure time” generally relates to any time that a forced occurrence could potentially take place and is formulaically represented in Schedule B to the RMR agreement.

it accounts for Available-But-Not-Operating (ABNO) and Available-But-Not-Staffed (ABNS) conditions in the metric's denominator.

The EFOR-OP target range used in calculating rewards or penalties is between 6.0% and 10.0% for the term of the agreement. The penalty provisions will apply if the EFOR-OP is above 10.0% and reward provisions will apply if the EFOR-OP is below 6.0%. The total net penalty/reward shall not exceed $500,000.

(b) Payment Terms
The RMR Agreement compensates OPG for the following cost components as described in Schedule A of the agreement:

1. A monthly fixed payment to cover costs that would be avoided by OPG if the facility was de-registered;
2. Market costs, which cover IESO charges related to the energy withdrawn from the IESO-controlled grid to maintain station operations;
3. Auxiliary boiler fuel costs and, in certain situations, costs incurred for regulatory testing; and,
4. A Net Revenue Sharing Adjustment ("NRSA"), which allows OPG to retain 5% of the operating profit (market revenue less actual fuel costs) when the RMR facility is dispatched to run. There is no NRSA when actual fuel costs exceed market revenues. This calculation is performed on a quarterly basis.

Variable costs are compensated through revenues earned in the IESO markets and not via this agreement.

The fixed monthly payment is based on a forecast of fixed costs (as opposed to actual fixed costs determined after the fact). This provides OPG with an extra incentive to manage these costs within the forecast budget. The Monthly Fixed Payment ("MFP") is $3.164M as derived in Table 1 of Schedule D of the agreement.

On a quarterly basis, the NRSA allows OPG to keep 5% of the operating profit earned by the RMR facility while offering no compensation when fuel costs exceed market revenues. This provides OPG with an incentive to offer the unit in an economically efficient manner.

The monthly fixed payment and market costs will appear on the IESO's monthly settlement invoice. The auxiliary boiler fuel and any regulatory testing costs as well as the NRSA will be settled quarterly based on actual fuel cost submissions by OPG to the IESO.

Within fifteen business days of the OEB's approval of the Agreement, OPG will prepare an invoice for settlement amounts prior to the date of approval of the Agreement. These accrued settlement amounts will be spread over the remaining term of the Agreement and paid by the IESO in equal monthly payments at the same time as the monthly settlement amounts are made. Interest at 2.62% will be applied to the outstanding balance of unpaid accrued settlement amounts. The total net cost of the RMR Agreement will be recovered from wholesale market participants as part of the monthly non-hourly uplift.

OPG must provide the IESO with all information used to calculate the detailed statements. The IESO must provide OPG with information to support its monthly revenue calculation for the one unit at Thunder Bay GS. Each party must respond to the other's reasonable information requests regarding its calculations. Moreover, the IESO has the right to conduct both financial and operational audits of OPG's information to determine its compliance with the RMR Agreement, including verification of OPG's submitted auxiliary boiler fuel costs, actual cost of fuel and information related to fuel management. OPG must assist in any such audit by retaining complete and accurate records, permitting access to them by the auditor, and furnishing such other assistance as the auditor may reasonably require.

(c) Termination

The Agreement runs from January 1, 2013 to December 31, 2013. The IESO can terminate the Agreement at any time upon written notice stating the effective date of the termination and by paying OPG termination costs. These costs include any out-of-pocket costs incurred or committed to by OPG as a result of the Agreement. Early termination of the Agreement by the IESO will constitute IESO approval for OPG to de-register the operating unit at Thunder Bay GS upon OPG's request.

OPG may terminate the Agreement at any time by withdrawing its request to de-register the operating unit at Thunder Bay GS. All payments which accrued prior to OPG withdrawing its de-registration request must be made, however OPG is not entitled to receive termination costs.

(d) Comparison with Previous RMR Contracts

Early in the negotiation process, the IESO indicated that it wanted to make some improvements to the existing form of RMR agreement that had been previously negotiated for Lennox GS. OPG indicated that it was prepared to consider improvements to the earlier agreements.

The improvements in the Agreement are as follows:

1. Previous contracts provided for the recovery of fixed and variable costs after-the-fact as determined and invoiced by OPG. As noted in section 4(b) above, this Agreement provides for a fixed monthly payment based on a mutually agreed forecast of fixed costs, with variable costs being recovered through IESO energy market revenues. The predetermined fixed payment provides an increased incentive for OPG to manage its costs within the agreed levels.

2. Previous contracts provided for a revenue sharing mechanism that allowed OPG to receive 5% of gross revenue. This Agreement provides for OPG to receive a smaller incentive; 5% of net revenues after deducting the actual costs of fuel used when dispatched. Consumers will benefit from the smaller incentive payment provided to OPG, while OPG still maintains a sufficient incentive to offer the unit efficiently into the IESO market.

3. In addition, Schedule E of the RMR Agreement provides that OPG will offer the facility in such a way as to manage its limited fuel supplies in order to meet the IESO's reliability needs and minimize its stranded fuel costs at the termination of the agreement.

<u>(e) OEB Assessment Criteria in Previous RMR Applications</u>
In previous RMR applications for Lennox GS, the OEB articulated three assessment criteria when considering whether or not to approve the agreements. In its Decision with Reasons (EB-2005-0490, page 3), the OEB considered RMR contracts from the following perspectives:

1. Does the RMR Contract comply with OPG's Licence?
2. Are the financial provisions of the RMR Contract reasonable?
3. What are the incentive effects, if any, of the RMR Contract?

The Board has previously been satisfied that the process that was followed by OPG and the IESO in negotiating RMR agreements for Lennox GS complied with both OPG's Licence conditions and the Ontario Market Rules. This same process was followed for this RMR Agreement. Similarly, the terms and conditions articulated in Chapter 7, Section 9.7 of the Market Rules have been satisfied in this Agreement.

The OEB has consistently found the financial terms to be reasonable for all of the Lennox RMR agreements. The proposed Thunder Bay RMR Agreement provides for the recovery of 100% of agreed upon fixed costs with variable costs being recovered through IESO energy market revenues. It also includes a net revenue sharing mechanism, which while less generous to OPG, continues to incent OPG to offer the units in an efficient manner. Finally, the agreement satisfies the requirement for incentives for physical performance.

This agreement contains improvements compared to previous agreements. A fixed monthly payment based on a forecast of fixed costs (as opposed to actual fixed costs determined after-the-fact) provides OPG with an extra incentive to manage these costs within the forecast budget. OPG's recovery of variable costs depends upon its participation in the IESO-administered markets.

Therefore, in OPG's view, the current contract clearly satisfies the criteria assessed by the Board in its previous considerations of RMR agreements.

5. Conclusion

The IESO has determined that de-registration of both units at Thunder Bay GS would put the IESO-controlled grid at undue risk and requested negotiations with OPG for a RMR agreement for one Thunder Bay GS unit. The resulting RMR Agreement is consistent with the Market Rules, the IESO's Technical Assessment and OPG's Generation Licence. The payment mechanism compensates OPG while recognizing the need to provide appropriate incentives to support reliability, maximize available revenues, and to address the risks inherent in plant operation.

The Agreement provides the IESO with access to all information necessary to verify and audit OPG's compliance with its obligations under the RMR Agreement, as and when necessary. It also allows the IESO to terminate the Agreement at any time should the IESO determine that one unit at Thunder Bay GS is no longer required to maintain the reliability of the IESO-controlled grid.

In OPG's view, the OEB should conclude that the attached Thunder Bay GS RMR Agreement is consistent with the requirements of the Market Rules and OPG's Generation Licence, and approve it as submitted.

Yours truly,

[Original signed by]

Andrew Barrett
Vice President, Regulatory Affairs

Att. Attachment 1 – IESO-OPGI Reliability Must-Run Agreement
Attachment 2 – OPG Notice of Request to De-register the Thunder Bay Generation Facilities
Attachment 3 – De-registration Correspondence from IESO to OPG
Attachment 4 – IESO Technical Assessment – Thunder Bay De-registration

AGREEMENT

Power to Ontario.
On Demand.

IESO - OPGI Reliability Must-Run Agreement

for Procurement of Physical Services from Thunder Bay Generating Station

Between

ONTARIO POWER GENERATION INC.

and

INDEPENDENT ELECTRICITY SYSTEM OPERATOR

January 1, 2013

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THIS AGREEMENT dated as of the 1st day of January, 2013

BETWEEN:

Ontario Power Generation Inc., a corporation duly incorporated and organized under the laws of the Province of Ontario, having its registered address and its principal place of business at 700 University Avenue, Toronto, Ontario, M5G 1X6 (the "*Physical Service Provider*")

- and -

Independent Electricity System Operator, a corporation established and continued under the *Electricity Act, 1998*, S.O. 1998, c. 15, Sched. A, as amended, having its registered address at Suite 410, 655 Bay Street, Toronto, Ontario, M5G 2K4 (the "*IESO*")

WHEREAS:

A. The *market rules* for the Ontario Electricity Market (the "*market rules*") and the policies established by the *IESO* under those rules set out:

i. the rights, obligations and qualifications of *market participants* associated with the registration and testing of *registered facility* to provide *physical services* into the *IESO-administered markets*;

ii. the rights and obligations of the *IESO* with respect to matters relating to the procurement of *physical services*; and

iii. the rights and obligations of *market participants* and the *IESO* with respect to the provision, monitoring and payment of *physical services*.

B. In November 2012, the *Physical Service Provider* submitted to the *IESO* a request to de-register all units comprising the Thunder Bay Generating Station. Pursuant to the *market rules*, the *IESO* performed a study that indicated the *reliability must-run facility* is required to be available for the purposes of *reliability*, other than in situations of overall adequacy of the *IESO-controlled grid*. Accordingly, the *IESO* commenced the required process with the *Physical Service Provider* to enter into a *reliability must-run contract* for the *reliability must-run facility*.

C. The *Parties* wish to enter into this *Agreement* in respect of the *reliability must-run facility* in order to permit the *Physical Service Provider* to recover in accordance with Schedule D the fixed and specified variable costs associated with conserving the availability of that facility and the fixed and specified variable costs associated with the production of electricity from that *facility*, while ensuring that the *Physical Service Provider* continues to operate the *reliability must-run facility* and participate in Ontario's electricity markets in a commercial, and commercially reasonable, manner, all on the terms and conditions set out herein.

NOW therefore, in consideration of the mutual covenants set forth herein and of other good and valuable consideration, the receipt and adequacy of which is hereby acknowledged, the *Parties* agree as follows:

ARTICLE 1
INTERPRETATION

1.1 **Incorporation of *Market Rules* Definitions:** Subject to Section 1.2 of this *Agreement*, italicized expressions used in this *Agreement* have the meanings ascribed thereto in Chapter 11 of the *market rules*.

1.2 **Supplementary Definitions:** In this *Agreement*, the following italicized expressions shall have the meanings set out below unless the context otherwise requires:

"accrued settlement amounts" shall have the meaning attributed to the term in Section 4(a) of Schedule A;

"actual cost of fuel" means the fuel costs submitted to the *IESO* by the *Physical Service Provider* in respect of the weighted average cost of coal as determined as of January 1, 2013 plus any ignition fuels and such amounts for the purchase of *required coal* as agreed to by the *Parties* in the event that the *IESO* directs the *Physical Service Provider* to do so.

"affiliate" has the meaning ascribed to that term in Section 1(2) of the *Securities Act* (Ontario);

"Agreement" means this *Agreement*, including the Schedules to this *Agreement*, as amended or supplemented from time to time, and the expressions "herein", "hereto", "hereunder", "hereby" and similar expressions refer to this *Agreement* and not to any particular section or other portion of this *Agreement*;

"auxiliary boiler fuel" means fuel that is used by the *Physical Service Provider* in an auxiliary boiler for the purpose of producing steam used for building heating, water treatment, safety systems and other *facility* requirements;

"business day" means any day, other than a Saturday, Sunday, any statutory holiday in the Province of Ontario, or any day on which banking institutions in Toronto, Ontario are not open for the transaction of business;

"company representative" means the representative of a *Party* appointed by that *Party* for the purposes specified in Section 9.2 of this *Agreement*, as identified in Schedule C;

"default" means either a *financial default* or a *material non-financial default*;

"***disposal costs***" means the *actual cost of fuel* less proceeds of disposition of such fuel plus any transportation and other related costs;

"***effective date***" means January 1, 2013, which, subject to Section 9.17 of this *Agreement,* shall be the date of commencement of this *Agreement*;

"***early termination payment***" means a payment, if any, made by the *IESO* pursuant to Section 7.3 or 9.14.4 of this *Agreement* and in accordance with Section 3 of Schedule A;

"***EFOR – OP***" has the meaning attributed to that term in Section 1 of Schedule B;

"***EFOR – OP target***" has the meaning attributed to that term in Section 2 of Schedule B;

"***financial default***" means a failure by a *Party* to pay any amount under this *Agreement* to the other *Party* when due, including any amount payable as compensation or indemnification for any loss or damage suffered by a *Party* which amount has been agreed by the *Parties* or, if disputed, has been determined in accordance with the dispute resolution procedures contemplated herein, where such failure is not cured within 10 days of either becoming aware of such failure or receiving notice thereof under Section 9.14.2 of this *Agreement*;

"***future facility-related products***" means all *related products* that relate to the *reliability must-run facility* and that were not capable of being traded by the *Physical Service Provider* in the *IESO-administered markets* or other markets on or before the date of this *Agreement*;

"***good utility practices***" means any of the practices, methods and activities adopted by a significant portion of the North American electric utility industry as good practices applicable to the operation of a generating *facility* of similar type, size and capacity or any of the practices, methods, or activities which, in the exercise of skill, diligence, prudence, foresight and reasonable judgment by a prudent *generator* in light of the facts known at the time the decision was made, could reasonably have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety, expedition and *applicable law*. *Good utility practices* are not intended to be limited to the optimum practices, methods or acts to the exclusion of all others, but rather are intended to delineate acceptable practices, methods, or acts generally accepted in the North American electric utility industry. Without limiting the generality of the foregoing and in respect of the operation of the *reliability must-run facility's good utility practices* include taking reasonable steps to ensure that:

a. adequate materials, resources and supplies, including fuel, are available to meet the *facility's* needs under reasonable conditions and reasonably anticipated abnormal conditions;

b. sufficient operating personnel are available and are adequately experienced and trained to operate the *facility* properly and efficiently and are capable of responding to abnormal conditions;

c. routine and non-routine maintenance and repairs are performed on a basis that ensures reliable and safe operation and are performed by knowledgeable, trained and experienced personnel utilizing proper equipment, tools and procedures; and

d. appropriate monitoring and testing is done to ensure equipment is functioning as designed and to provide assurance that equipment shall function properly under both normal and abnormal conditions;

"***governmental authority***" means any domestic government, including any federal, provincial, municipal or local government, and any government agency, tribunal, commission or other authority exercising or purporting to exercise executive, legislative, judicial, regulatory or administrative functions of, or pertaining to, government, in each case having or purporting to have jurisdiction in the relevant circumstances;

"***IESO's audit rights***" means the *IESO's* rights set out in Section 4.4 of this *Agreement*;

"***indemnitees***" has the meaning ascribed to that term in Section 3.6 of this *Agreement*;

"***interest rate***" shall be 2.62% as established by the *Physical Service Provider's* credit facility agreement based on a one year banker's acceptance rate

"***insolvency event***" means the occurrence of any one or more of the following events:

a. the *Party* ceases or threatens to cease to carry on its business or a substantial part of its business as a *generator* or as an independent system operator, as the case may be, but in the case of a *generator*, does not include ceasing to generate electricity from coal, where such cessation has been approved by the relevant *governmental authorities*, or the sale of any generating station (other than the *reliability must-run facility*) that has been approved by the relevant *governmental authorities*;

b. the *Party* enters into or takes any action to enter into an arrangement, composition or compromise with, or an assignment for the benefit of, all or any class of its creditors or members or a moratorium involving any of them;

c. the *Party* is, or states that it is, unable to pay from its own money its debts when they fall due for payment;

d. a receiver or receiver and manager or person having a similar or analogous function under the laws of any relevant jurisdiction is appointed in respect of any property of the *Party* which is used in or relevant to the performance by the *Party* of any of the obligations imposed on a *Party* either as a provider of *physical services* with respect to the *reliability must-run facility* or as an independent system operator, as the case may be, under the *market rules* or with respect to any of the *Party's* obligations under this *Agreement*;

e. an administrator, liquidator, trustee in bankruptcy or person having a similar or analogous function under the laws of any relevant jurisdiction is appointed in respect of the *Party*, or any action is taken to appoint such person;

f. an application is made for the winding up or dissolution of a *Party* or a resolution is passed or any steps are taken to pass a resolution for the winding up or dissolution of that *Party*;

g. the *Party* is wound up or dissolved, unless the notice of winding up or dissolution is discharged; or

h. a court determines that the *Party* is insolvent or unable to pay its debts;

*"**market costs**"* means charges accruing to the *reliability must-run facility* related to *energy* withdrawn from the *IESO-controlled grid* including, but not limited to, hourly *settlement amounts* in the real-time *energy market*, all hourly, daily and monthly uplifts, all rate based load related charges, network service changes, transformation connection service charges and the Global Adjustment.

"***market revenue***" means the aggregate revenues earned by or attributed to the *Physical Service Provider* from or attributed to the *reliability must-run facility* as determined in accordance with the *Market Rules* including:

a. Hourly *Settlement Amounts* in Real-Time *Energy Market* set forth in Section 3.3 of Chapter 9 for *energy* injected into the *IESO-controlled grid.*

b. Hourly *Settlement Amounts* for *Operating Reserve* set forth in Section 3.4 of Chapter 9.

c. Hourly *Settlement Amounts* for Congestion Management set forth in Section 3.5 of Chapter 9.

d. Real-Time Generation Cost Guarantee Payments set forth in Section 2.2B of Chapter 7 and Section 4.7B of Chapter 9.

e. Day-Ahead Production Cost Guarantee Payments set forth in Section 2.2C of Chapter 7 and Section 4.7D of Chapter 9.

f. *Reactive support service* and *voltage control service* payments as set forth in Section 4.2.4 of Chapter 9.

"***material non-financial default***" means:

a. a breach of a term or condition of this *Agreement*, excluding a *financial default*, by a *Party* which results in, has or is reasonably expected to have, a material adverse effect on the non-defaulting *Party*'s ability to obtain and enjoy the primary rights and benefits under this *Agreement,* including, without limitation, in the case of the *Physical Service Provider*, a breach of Section 3.3; or

b. in the case of the *Physical Service Provider*, it transfers all or substantially all of the *reliability must-run facility* to another person unless, at the time of such transfer, there has been a permitted and valid assignment of this *Agreement* by the *Physical Service Provider* under this *Agreement* to the transferee person and such person has assumed all of the *Physical Service Provider*'s obligations under this *Agreement*;

where such breach or transfer is not cured within 30 days of either becoming aware of such breach or transfer or receiving notice thereof under Section 9.14.2;

"monthly accrued payment" shall have the meaning attributed to the term in Section 4b of Schedule A;

"monthly fixed payment ("MFP")" shall have the meaning attributed to the term in section 5 of Schedule D.

"net penalty/reward" means the total net *penalty* or *reward* payable pursuant to, and as further specified in, Section 3 of Schedule B;

"net penalty/reward statement" means the statement prepared and delivered by the *IESO* calculating in detail the *net penalty/reward* to be received by the relevant *Party*, as specified in subsection 4(b) of Schedule B;

"net revenue sharing adjustment ("NRSA")" shall have the meaning attributed to the term in section 6 of Schedule D.

"non-IESO market revenue" means the aggregate gross revenues earned by or attributed to the *Physical Service Provider* in respect of the *reliability must-run facility*, other than *IESO market revenue* earned through the *term*;

"OM&A costs" means the *Physical Service Provider*'s costs, associated with the operation, maintenance and administration of the *reliability must-run facility* through the *term*, as specified in Schedule D;

"other costs" means the *Physical Service Provider*'s costs, other than fuel costs, *OM&A costs*, or *market costs*, associated with operating the *reliability must-run facility* through the *term*, as specified in the Schedule D;

"Party" means a party to this *Agreement* and "*Parties*" means every *Party;*

"penalty" means the penalty, if any, to which the *Physical Service Provider* is subject pursuant to the performance standards of Schedule B, calculated with reference to *performance points* in accordance with Section 3 of that schedule;

"performance point" has the meaning attributed to that term in Section 3 of Schedule B;

"***regulatory testing***" means testing of the *reliability must-run facility* required by a *governmental authority*;

"***related products***" means any products related to the rated, continuous load-carrying capability of the *reliability must-run facility* to generate and deliver *energy* at a given time, *ancillary services*, and any other products or services that may be provided by the *reliability must-run facility* from time to time, that may be traded in the *IESO-administered markets* or other markets, or otherwise sold, and which shall be deemed to include products and services for which no market exists as of the date of this *Agreement*, such as *capacity reserves*;

"***reliability must-run facility***" means the Thunder Bay Generating Station Unit G3 and related facilities required for the operation of G3 located at 108th Avenue, Mission Island, Thunder Bay, Ontario.

"***required coal***" means a specific quantity of coal specified by the *IESO* to the *Physical Service Provider* in GWh as being required to meet potential *reliability* requirements at the *reliability must-run facility*.

"***reward***" means the reward, if any, to which the *Physical Service Provider* is entitled pursuant to the performance standards of Schedule B, calculated with reference to *performance points* in accordance with Section 3 of that schedule;

"***term***" has the meaning set out in section 7.1;

"***termination costs***" means the actual out-of-pocket costs, if any, incurred or to be incurred by the *Physical Service Provider* which directly relate to this *Agreement* and for which the *Physical Service Provider* is contractually committed and which, acting commercially reasonably, cannot be avoided or mitigated and which have been initiated prior to notice of any termination of this *Agreement* by the *IESO* pursuant to Section 7.3 of this *Agreement* or as a result of the *IESO's default* pursuant to Section 9.14.4 of this *Agreement*, but excluding, for greater certainty, any costs relating to the de-registration and removal from service of the *reliability must-run facility* or any decommissioning costs relating thereto; and

"***termination costs statement***" means the statement prepared and delivered by the *Physical Service Provider* calculating in detail the *termination costs* to be received by the *Physical Service Provider*, as specified in subsection 3(b)(i) of Schedule A.

1.3 **Interpretation:** In this *Agreement*, unless the context otherwise requires:

1.3.1 words importing the singular include the plural and vice versa;

1.3.2 words importing a gender include any gender;

1.3.3 when italicized, other parts of speech and grammatical forms of a word or phrase defined in this *Agreement* have a corresponding meaning;

1.3.4 the expression "person" includes a natural person, any company, partnership, trust, joint venture, association, corporation or other private or public body corporate, and any government agency or body politic;

1.3.5 a reference to an article, section, provision or schedule is to an article, section, provision or schedule of this *Agreement;*

1.3.6 a reference to any statute, regulation, proclamation, order-in-council, ordinance, by-law, resolution, rule, order or directive includes all statutes, regulations, proclamations, orders-in-council, ordinances, by-laws or resolutions, rules, orders or directives varying, consolidating, re-enacting, extending or replacing any of them and a reference to a statute includes all regulations, proclamations, orders-in-council, rules and by-laws of a legislative nature issued under that statute;

1.3.7 a reference to a document or provision of a document, including this *Agreement* and the *market rules* or a provision of this *Agreement* or the *market rules*, includes an amendment or supplement to, or replacement or novation of, that document or that provision of that document, as well as any exhibit, schedule, appendix or other annexure thereto;

1.3.8 a reference to a person includes that person's heirs, executors, administrators, successors and permitted assigns;

1.3.9 a reference to sections of this *Agreement* or of the *market rules* separated by the word "to" (i.e., "Sections 1.1 to 1.4") shall be a reference to the sections inclusively; and

1.3.10 the expression "including" means including without limitation, the expression "includes" means includes without limitation and the expression "included" means included without limitation.

1.4 **Headings:** The division of this *Agreement* into articles and sections and the insertion of headings are for convenience of reference only and shall not affect the interpretation of this *Agreement*, nor shall they be construed as indicating that all of the provisions of this *Agreement* relating to any particular topic are to be found in any particular article, section, subsection, clause, provision, part or schedule.

ARTICLE 2

MARKET RULES

2.1 ***Market Rules* Govern:** The interpretation of this *Agreement* shall be purposive and liberal so as to avoid to the extent reasonably possible findings of inconsistency between this *Agreement* and the *market rules*. In the event of any inconsistency between this *Agreement* and the *market rules*, the *market rules* shall prevail to the extent of the inconsistency. Notwithstanding the foregoing, italicized expressions defined in this *Agreement* shall prevail over any equivalent italicized expressions defined in the *market rules*.

ARTICLE 3

RIGHTS AND OBLIGATIONS IN RELATION TO THE PHYSICAL SERVICE PROVIDER

3.1 **Compliance with *Market Rules* and *Applicable Law*:** The *Physical Service Provider* hereby agrees to be bound by and to comply with all of the provisions of the *market rules*, so far as they are applicable to the *Physical Service Provider* and this *Agreement*, in the same manner as if such provisions formed part of this *Agreement*. Without limiting the generality of the foregoing, the *Physical Service Provider:*

i. acknowledges and agrees that the *IESO* shall have the ability to call on the *reliability must-run facility* in accordance with Chapter 7, Section 9 of the *market rules*; and

ii. shall comply with Chapter 5, Sections 3.6 and 4.8 of the *market rules*.

The *Physical Service Provider* further hereby agrees to be bound by and to comply, in all material respects with, all *applicable law* required to perform or comply with its obligations under this *Agreement*.

3.2 **Ownership and Operation of Facility:** Subject to Section 9.4 of this *Agreement*, the *Physical Service Provider* agrees to own the *reliability must-run facility* during the *term* of this *Agreement* and to operate and maintain such facility during the *term* using *good utility practices* and meeting all requirements of *applicable law*.

3.3 **Participation in Markets:** Without limiting the terms of the *market rules* and the *Physical Service Provider*'s electricity generation *licence* with the *Ontario Energy Board*, the *Physical Service Provider* shall participate in the *IESO-administered markets* and in other electricity markets with respect to the *reliability must-run facility*, including making day-ahead *offers* in the *energy market* and the *operating reserve market* in accordance with Section 3.3A of Chapter 7 of the *market rules* and participating in any *IESO-administered market* or any other market that develops in *future facility-related products*, in a commercially reasonable manner and in accordance with the *Physical Service Provider*'s mandate, including in accordance with the provisions of Schedule A. For greater certainty, acting in a "commercially reasonable manner" with respect to any given activity includes, other than in exceptional circumstances, that the *Physical Service Provider* will offer a unit economically over a sustained period of time based on its costs and in a manner consistent with how the *Physical Service Provider's* coal-fired generation is being offered pursuant to the *Physical Service Provider's* CO_2 Implementation Strategy, as amended from time to time.

3.4 **Insurance:** The *Physical Service Provider* shall maintain all necessary and appropriate insurance that a prudent person in the business of the *Physical Service Provider* operating the *reliability must-run facility* would maintain in respect of such *facility*.

3.5 **Permits, *Licences* and Authorizations:** The *Physical Service Provider* shall at all times hold and maintain in good standing all permits, *licences* and other authorizations that may be necessary to enable it to carry on the business and perform the functions and obligations to provide *physical services* with respect to the *reliability must-run facility* as described in the *market rules* and in this *Agreement*, including maintaining its electricity generation *licence* with the *Ontario Energy Board.*

3.6 **Assumption of Risk:** The *Physical Service Provider* agrees to assume all risk, liability and obligation and to indemnify, defend and hold harmless the *IESO* and its *affiliates*, and each of the foregoing persons' respective directors, officers, employees, shareholders, advisors and agents (including contractors and their employees) (collectively, the "*indemnitees*"), in respect of all actions, causes of action, suits, proceedings, claims, demands, losses, damages, penalties, fines, costs, obligations and liabilities arising out of a discharge of any contaminant into the natural environment, at or related to, the *reliability must-run facility* and any fines or orders of any kind that may be levied or made in connection therewith pursuant to the *Environmental Protection Act* (Ontario), the *Ontario Water Resources Act*, or the *Dangerous Goods Transportation Act* (Ontario), or other similar legislation whether federal or provincial, except to the degree that such discharge shall have been due to the negligence of the *indemnitees.*

3.7 **Information:** The *Physical Service Provider* shall promptly disclose or provide to the *IESO* such information as is required to be disclosed or provided to the *IESO* pursuant to this *Agreement*. Information disclosed or provided by the *Physical Service Provider* shall be, to the best of the *Physical Service Provider*'s knowledge, true, correct and complete at the time at which such disclosure or provision is made, acting reasonably. Where the *Physical Service Provider* discovers that any such information that is material and has been previously disclosed or provided by it to the *IESO* was or, in the *Physical Service Provider*'s opinion, is reasonably likely to become, materially untrue, incorrect, or incomplete, the *Physical Service Provider* shall as soon as reasonably practicable in the circumstances rectify the situation and disclose or provide the true, correct, or complete information to the *IESO*.

3.8 **Notification of Significant Events**: The *Physical Service Provider* shall, as soon as reasonably practicable in the circumstances, notify the *IESO* of the occurrence of, or upon becoming aware of any circumstances that may give rise to, any of the following events during the *term* of this *Agreement*:

3.8.1 if it becomes unlawful for the *Physical Service Provider* to comply with any of the obligations imposed on it under the *market rules* or with any of the *Physical Service Provider*'s obligations under this *Agreement*;

3.8.2 a *licence*, permit or other authorization referred to in Section 3.5 of this *Agreement* is suspended, revoked, materially and adversely amended or otherwise ceases to be in full force and effect;

3.8.3 if the *Physical Service Provider* experiences an *insolvency event;*

3.8.4 if the *Physical Service Provider* ceases, or threatens or intends to cease, to carry on its business or a substantial part of its business of either owning or operating the *reliability must-run facility*;

3.8.5 the development by the *Physical Service Provider* of any *future facility-related product* in any *IESO-administered market* or other market; and

3.8.6 any other event in respect of the *Physical Service Provider* that is likely to materially affect the performance by the *Physical Service Provider* of its obligations under the *market rules* or this *Agreement* in relation to the provision of *physical services* from the *reliability must-run facility*.

3.9 **Performance Standards**: Nothing in this *Agreement* shall require the *Physical Service Provider* to operate the *reliability must-run facility* during an *outage*, or where to do so would endanger the safety of any person, damage equipment, harm the environment or violate any *applicable law*. Subject to the foregoing, the *Physical Service Provider* shall use commercially reasonable efforts in accordance with *good utility practices* to provide the *physical services* from the *reliability must-run facility* according to the performance standards described in Schedule B, including operating the generating unit comprising the *reliability must-run facility* in accordance with Schedule B.

3.10 **Record Retention and *IESO* Audits:** The *Physical Service Provider* shall keep complete and accurate books, records and all other data required by it for the purpose of proper administration of, and compliance with, this *Agreement*. All such books, records and data shall be maintained as required by *applicable law* but for no less than for three (3) years after the creation of the book, record or data. The *Physical Service Provider*, on a confidential basis as provided for in Article 6, shall provide reasonable access to the *IESO*, any auditor appointed by the *IESO* pursuant to Section 4.4 of this *Agreement* and any of the *IESO's representatives*, to such books, records and data kept and shall provide any assistance the *IESO* or any such auditor may reasonably require in order to conduct audits pursuant to Section 4.4.

ARTICLE 4

RIGHTS AND OBLIGATIONS IN RELATION TO THE IESO

4.1 **Compliance with *Market Rules* and *Applicable Law*:** The *IESO* hereby agrees to be bound by and to comply with all of the provisions of the *market rules* so far as they are applicable to the *IESO* in the same manner as if such provisions formed part of this *Agreement*, and to be bound by and to comply, in all material respects with, all *applicable law* required to perform or comply with its obligations under this *Agreement*.

4.2 **Information:** The *IESO* shall promptly disclose or provide to the *Physical Service Provider* such information as is required to be disclosed or provided to the *Physical Service Provider* pursuant to this *Agreement*. Information disclosed or provided by the *IESO* shall be, to the best of the *IESO's* knowledge, true, correct and complete at the time at which such disclosure or provision is made, acting reasonably. Where the *IESO* discovers that any such information that is material and has been previously disclosed or provided by it to the *Physical Service Provider* was or, in the *IESO's* opinion, is reasonably likely to become, materially untrue, incorrect, or incomplete, the *IESO* shall as soon as reasonably practicable in the circumstances rectify the situation and disclose or provide the true, correct or complete information to the *Physical Service Provider.*

4.3 **Notification of Significant Events**: The *IESO* shall, as soon as reasonably practicable in the circumstances, notify the *Physical Service Provider* of the occurrence of, or upon becoming aware of any circumstances that may give rise to, any of the following events during the *term* of this *Agreement*:

4.3.1 if it becomes unlawful for the *IESO* to comply with any of the obligations imposed on the *IESO* under the *market rules* or with any of the *IESO's* obligations under this *Agreement*;

4.3.2 a *licence*, permit or other authorization that is necessary to enable the *IESO* to carry on its business as an independent system operator and perform its obligations under this *Agreement*, is suspended, revoked, materially and adversely amended or otherwise ceases to be in full force and effect;

4.3.3 if the *IESO* experiences an *insolvency event*; and

4.3.4 any other event that is likely to materially affect the performance by the *IESO* of its obligations under the *market rules* or this *Agreement* including, without limiting the generality of the foregoing, proposed changes to the *market rules* which are likely to have a material effect on the *Physical Service Provider's* rights and obligations relating to the provision of *physical services* from the *reliability must-run facility* under this *Agreement.*

4.4 **Audits:**

4.4.1 The *IESO*, at its own cost, shall have the right, acting reasonably, to initiate one or more audits during normal business hours and upon reasonable notice, at any time during the *term* and within a period of four months from the expiration or termination of this *Agreement*, of the books, records, data, procedures and operations of the *Physical Service Provider* in order to verify compliance by the *Physical Service Provider* with its obligations under this *Agreement*, including verification of its submitted *auxiliary boiler fuel* costs, *actual cost of fuel* and information related to fuel management at the *reliability must-run facility* as set forth in Schedule E. For greater clarity, any amounts included in the *monthly fixed payment* shall not be subject to audit.

4.4.2 Any such audit shall be conducted at the *IESO's* own expense and shall be conducted by a third party appointed by the *IESO* unless the *Physical Service Provider*, acting reasonably, consents to the conduct of an audit by the *IESO*. If the *IESO* conducts the audit itself, it may use its own employees for purposes of any such audit provided that those employees are bound by the confidentiality requirements provided for in Article 6. For greater certainty, any third party auditor appointed by the *IESO* to conduct an audit and any *IESO* employee involved in conducting an audit shall have the right to discuss and share information only with respect to the *reliability must-run facility* with or within the *IESO*, as the case may be, concerning an audit, subject in all cases to the confidentiality requirements provided for in Article 6 and the confidentiality and non-disclosure agreement executed by the auditor pursuant to Section 4.5 of this *Agreement*.

4.4.3 If the *Physical Service Provider* has a confidentiality obligation to a third party with respect to any of its books, records, data, procedures or operations that are relevant to the conduct of an audit pursuant to this *Agreement*, and the *Physical Service Provider* is unable, using commercially reasonable efforts, to obtain consent to the release thereof to a third party auditor, the *IESO* or its *representatives*, the *Physical Service Provider* shall provide a certificate executed by a nationally recognized, independent auditing firm attesting to the accuracy and completeness of such books, records, data, procedures or operations, and any information reflected therein as may be reasonably requested by the *IESO*.

4.4.4 The *IESO* or the third party appointed to conduct any audit shall provide to the *Physical Service Provider* the terms of reference of the audit plan and audit procedures at least ten (10) *business days* prior to the commencement of the audit in order to assist the *Parties* in planning the audit. The *IESO* acknowledges and agrees that the *Physical Service Provider*'s readiness for an audit shall be dependent in part on the scope of the audit, and that, notwithstanding its commercially reasonable efforts, the *Physical Service Provider* may not be fully prepared to assist in the conduct of an audit at the end of such ten (10) *business days*. Notwithstanding the foregoing, the *Physical Service Provider* shall be so prepared as soon as is reasonably possible in the circumstances.

4.5 **Audit Confidentiality**: Any auditor appointed by the *IESO* pursuant to Section 4.4 of this *Agreement* shall enter into a Confidentiality Agreement with the *Physical Service Provider* substantially in the form of Schedule E.

ARTICLE 5
REPRESENTATIONS AND WARRANTIES

5.1 **Representations and Warranties of the *IESO*:** The *IESO* hereby represents and warrants that:

5.1.1 the *IESO* is a corporation established and continued under the *Electricity Act, 1998* (Ontario), is qualified to carry on its business in the Province of Ontario, and has the requisite power to enter into this *Agreement* and to perform its obligations hereunder;

5.1.2 the execution, delivery and performance of this *Agreement* by it has been duly authorized by all necessary corporate and/or governmental action;

5.1.3 this *Agreement* constitutes a legal and binding obligation of the *IESO*, enforceable against the *IESO* in accordance with its terms, except as such enforcement may be limited by bankruptcy, insolvency and other laws affecting the rights of creditors generally and except that equitable remedies may only be granted in the discretion of a court of competent jurisdiction; and

5.1.4 the *IESO* has reviewed this *Agreement* to ensure its consistency with and full compliance with the provisions of the *IESO's licence* and the *market rules* and, to the best of the *IESO's* knowledge, this *Agreement* is consistent with and in full compliance with the provisions of the *IESO's licence* and the *market rules*.

5.2 **Representations and Warranties of the *Physical Service Provider*:** The *Physical Service Provider* hereby represents and warrants that:

5.2.1 the *Physical Service Provider* is a corporation incorporated under the laws of the Province of Ontario, is registered or otherwise qualified to carry on business in the Province of Ontario, and has the requisite power to enter into this *Agreement* and to perform its obligations hereunder;

5.2.2 the execution, delivery and performance of this *Agreement* by it has been duly authorized by all necessary corporate and/or governmental action;

5.2.3 this *Agreement* constitutes a legal and binding obligation of the *Physical Service Provider*, enforceable against the *Physical Service Provider* in accordance with its terms, except as such enforcement may be limited by bankruptcy, insolvency and other laws affecting the rights of creditors generally and except that equitable remedies may only be granted in the discretion of a court of competent jurisdiction; and

5.2.4 the information provided by the *Physical Service Provider* and set out in Schedule D with respect to its costs included in the *monthly fixed payment* to operate the *reliability must-run facility* represent costs that are consistent with the operation of the *reliability must-run facility* in accordance with *good utility practices*, acting in a commercially reasonable manner. For greater clarity these costs only include those costs that would be avoided if the *reliability must-run facility* was decommissioned.

ARTICLE 6
CONFIDENTIALITY

6.1 ***Market Rules Confidentiality* Obligations:** Each *Party* shall keep confidential any *confidential information* pertaining to the other *Party* in accordance with the provisions of the *market rules*. The *Parties* agree that confidential information does not constitute "relevant terms and conditions of the contracts" within the meaning of Chapter 7, Section 9.8.1.4 of the *market rules*.

6.2 **Additional Confidentiality Obligations:** In addition to the confidentiality provisions *of the market rules* the following provisions shall also apply to any *confidential information*. *Confidential information* shall include all analyses, compilations, forecasts, studies or other documents prepared by a receiving *Party* which contain *confidential information*. The *Party* receiving the *confidential information* shall:

6.2.1 not make any copies or reproductions of the *confidential information* in any medium or form other than as reasonably necessary to carry out the terms of this *Agreement*;

6.2.2 only disclose the *confidential information* to such of its *representatives* or employees who need to know the *confidential information* to carry out the terms of this *Agreement*. The receiving *Party* specifically acknowledges that it shall be solely responsible to ensure that its *representatives* and employees are bound by the terms of this *Agreement* and the receiving *Party* shall defend, indemnify and hold harmless the disclosing *Party* from and against all suits, actions, damages, claims and costs arising out of any breach of this *Agreement* by such *representatives* and employees;

6.2.3 upon the expiration or other termination of this *Agreement*, and subject to the survival rights contained in Section 7.5 of this *Agreement*, at the request of the disclosing *Party*, return or destroy all *confidential information* disclosed or otherwise obtained in writing or in any medium or form, including copies or reproductions thereof, and destroy all analyses, compilations, forecasts, studies or other documents prepared by the receiving P*arty* which contain *confidential information*, including all copies or reproductions thereof, and certify to the disclosing P*arty* that it has done so;

6.2.4 if it is legally compelled to disclose any *confidential information*, it shall provide the disclosing *Party* with prompt notice so that the disclosing *Party* may seek injunctive relief or other appropriate remedies and/or waive compliance with the provisions of this *Agreement*. Furthermore, the receiving *Party* shall use reasonable efforts to assist the disclosing *Party* to contest and resist such disclosure, request, requirement or order. If the *Parties* are unable to prevent the further transmission of the *confidential information*, the receiving P*arty* shall use reasonable efforts to obtain assurances that confidential treatment will be afforded to that portion of the *confidential information* furnished; and

6.2.5 not dispute that the disclosing *Party* would be irreparably injured by a breach of Article 6 of this *Agreement* and would be entitled to equitable relief, including injunctive relief and specific performance as may be granted by any court of competent jurisdiction to prevent breaches of Article 6 and to enforce specifically the terms and provisions hereof in any action instituted in any court having jurisdiction.

The provisions of this Section 6.2 shall apply to any *representatives* who receive *confidential information* pursuant to Section 4.4 or 4.5 of this *Agreement.*

ARTICLE 7
TERM AND TERMINATION

7.1 **Term:** This *Agreement* comes into force as of the *effective date* and shall remain in full force and effect until the earlier of (the "*term*"):

a. one year after the *effective date*; and

b. termination of this *Agreement* under Section 7.3, 7.4 or 9.14.

7.2 **No Right to Extend or Renew:** Neither *Party* shall have any right to extend or renew the *term* of this *Agreement.*

7.3 **Termination by *IESO*:**

7.3.1 The *IESO* may terminate this *Agreement* at any time upon written notice to the *Physical Service Provider* specifying the effective date of termination. To the extent reasonably possible, the *IESO* shall provide prior written notice of such termination to the *Physical Service Provider.*

7.3.2 In the event of such termination, the *IESO* shall reimburse the *Physical Service Provider* for its *termination costs,* provided that the *Physical Service Provider* has provided to the *IESO*, acting reasonably, satisfactory written evidence of the costs so incurred.

7.3.3 In the event and as of the date of such termination, the *Physical Service Provider*'s request to de-register the *reliability must-run facility* shall be deemed to have been approved by the *IESO*, and the *IESO* shall be considered not to have required a technical assessment of such request and to have concluded that the removal from service of the *reliability must-run facility* would not or would not be likely to have an unacceptable impact on the *reliability* of the *IESO-controlled grid,* all in accordance with Chapter 7, Section 2.4.3 of the *market rules.* For greater certainty, if the *Physical Service Provider* wishes to de-register the *reliability must-run facility* upon any such termination, it shall be required to provide notice to the *IESO* in accordance with such Section 2.4.3 and to comply with all other obligations under the *market rules* in order to effect such de-registration.

7.4 **Termination by *Physical Service Provider*:** The *Physical Service Provider* may terminate this *Agreement* at any time by withdrawing its request to de-register the *reliability must-run facility* by written notice to the *IESO*. The *Physical Service Provider* shall be considered to have terminated this *Agreement* as of the date of such withdrawal. To the extent reasonably possible, the *Physical Service Provider* shall provide prior written notice of such withdrawal and termination to the *IESO*. In the event of such termination, the *Physical Service Provider* shall be entitled to, or obligated to make, all payments accruing to the date of such termination but shall not be entitled to be reimbursed for its *termination costs.*

7.5 **Survival:** The provisions of:

7.5.1 Sections 3.6, 3.10, 4.4, 4.5, Article 6, Sections 8.3, 9.1 and 9.13 shall survive the expiration of the *term* or any other termination of this *Agreement*;

7.5.2 Sections 2, 3, 4 and 5 of Schedule A and Schedule B shall survive the expiration of the *term* or any other termination of this *Agreement* until such time as any payments required to be made pursuant to those sections have been made; and

7.5.3 Article 5 shall survive the expiration of the *term* or any other termination of this *Agreement* for a period of one (1) year following such expiration or termination.

Termination or expiration of all or part of this *Agreement* for any reason does not affect any rights of either *Party* against the other which:

a. arose prior to or at the time at which such termination or expiration occurred; or

b. otherwise relate to or may arise at any future time from any breach or non-observance of an obligation under this *Agreement* occurring prior to the termination or expiration.

These rights shall survive the expiration of the *term* or earlier termination of this *Agreement* for a period of time equal to the applicable statute of limitation.

ARTICLE 8

PAYMENT

8.1 **Payments:** Each *Party* shall make all payments required to be made to the other *Party* pursuant to this *Agreement* including *settlement amounts*, *early termination payments*, and *net penalty/reward payments* in accordance with the timing specified in Schedule A or Schedule B, as applicable.

8.2 **Taxes:** Each of the *IESO* and the *Physical Service Provider* is liable for and shall pay, or cause to be paid, or reimburse the other *Party* if that other *Party* has paid, all taxes applicable on any payment due to the other *Party* other than on its income or capital. Any goods and services tax or harmonized sales tax exigible pursuant to the Excise Tax Act (Canada) and any Ontario provincial sales tax exigible under the Retail Sales Tax Act (Ontario) payable in connection with such payments shall be paid by the payor.

8.3 **Payment Records:** The *Parties* shall keep all books, records and data necessary to support the information contained in and with respect to each payment made hereunder.

ARTICLE 9
MISCELLANEOUS

9.1 **Dispute Resolution:** Except as otherwise provided in Schedule A, any dispute that arises under this *Agreement* shall be dealt with in accordance with the provisions of Chapter 3, Section 2 of the *market rules* and any applicable *licence* issued by the *OEB*.

9.2 ***Company Representative*:** Each *company representative* shall be duly authorized to act on behalf of the *Party* that has made the appointment, and with whom the other *Party* may consult at all reasonable times, and whose instructions, requests and decisions, provided the same are in writing signed by the *company representative*, shall be binding on the appointing *Party* as to all matters pertaining to this *Agreement*. The *company representatives* shall not have the power or authority to amend this *Agreement*.

9.3 **Amendment:** No amendment of this *Agreement* shall be effective unless made in writing and signed by the *Parties*.

9.4 **Assignment:** This *Agreement* may not be assigned, whether absolutely, in whole or in part, by a *Party* without the prior written consent of the other *Party*, such consent not to be unreasonably withheld or delayed. Upon any such assignment, the assigning *Party* shall be relieved of any further obligations under this *Agreement*.

9.5 **Successors and Assigns:** This *Agreement* shall enure to the benefit of, and be binding on, the *Parties* and their respective heirs, administrators, executors, successors and permitted assigns.

9.6 **Further Assurances:** Each *Party* shall promptly do such further acts and execute and deliver or cause to be done, executed and delivered all further acts and documents in connection with this *Agreement* that the other *Party* may reasonably require for the purposes of giving effect to this *Agreement*.

9.7 **Waiver:** A waiver of any *default*, breach or non-compliance under this *Agreement* is not effective unless in writing and signed by the non-defaulting *Party*. No waiver shall be inferred or implied by any failure to act or by the delay in acting by a non-defaulting *Party* in respect of any *default*, breach or non-observance or by anything done or omitted to be done by the defaulting *Party*. The waiver by a *Party* of any *default*, breach or non-compliance under this *Agreement* shall not operate as a waiver of that *Party*'s rights under this *Agreement* in respect of any continuing or subsequent *default*, breach or non-observance (whether of the same or any other nature).

9.8 **Severability:** Any provision of this *Agreement* that is invalid or unenforceable in any jurisdiction shall, as to that jurisdiction, be ineffective to the extent of that invalidity or unenforceability and shall be deemed severed from the remainder of this *Agreement*, all without affecting the validity or enforceability of the remaining provisions of this *Agreement* or affecting the validity or enforceability of such provision in any other jurisdiction.

9.9 **Notices:** Any notice, demand, consent, request or other communication required or permitted to be given or made under this *Agreement* shall be given or made in the manner set forth in Chapter 1, Section 8 of the *market rules*. Either *Party* may change its address and *company representative* as set forth in Schedule C by written notice to the other *Party* given in accordance with this Section 9.9. Such change shall not constitute an amendment to this *Agreement* for the purposes of the application of Section 9.3 of this *Agreement*.

9.10 **Governing Law:** This *Agreement* shall be governed by and construed in accordance with the laws of the Province of Ontario and the laws of Canada applicable therein.

9.11 **Counterparts:** This *Agreement* may be executed in any number of counterparts, each of which shall be deemed to be an original and all of which taken together shall be deemed to constitute one and the same instrument. Counterparts may be executed either in original, faxed or other electronically-communicated form and the *Parties* adopt any signatures received by a receiving facsimile machine or otherwise received electronically as original signatures of the *Parties*; provided, however, that any *Party* providing its signature in such manner shall promptly forward to the other *Party* an original signed copy of this *Agreement* which was so faxed or electronically delivered.

9.12 **Third Party – Beneficiaries:** In connection with this *Agreement*, the *Parties* shall be acting on their own behalf and shall benefit from the limitations of liability and other provisions of this *Agreement*. The *Parties* shall not be acting as agent, fiduciary or trustee for any other person or legal entity, and accordingly it is the *Parties*' intention that no person or legal entity other than the *Parties* hereto shall have any rights or remedies under or the ability to enforce this *Agreement* in any manner, directly or indirectly. The *Parties* further agree that the foregoing provisions shall not act as a waiver of subrogation by the *Parties*' insurers.

9.13 **Liability, Indemnification and Force Majeure:** The *Parties* acknowledge and agree that Chapter 1, Section 13 of the *market rules* applies to this *Agreement*.

9.14 ***Default:*** If an *insolvency event* occurs in relation to a *Party* or, in the case of the *Physical Service Provider*, it provides notice to the *IESO* pursuant to Section 3.8.4 of this *Agreement*, then the other *Party* may terminate this *Agreement* at any time by notice to that first *Party*. If the other *Party* gives a termination notice under this clause, then this *Agreement* terminates from the start of the later of the day following the day on which the notice was given and the day nominated in the notice.

9.14.1 **Notice by *Party* in Breach:** If a *Party* becomes aware that a circumstance has arisen which that *Party* reasonably considers constitutes or is likely to constitute or result in a *default* by it (for greater certainty, without reference to the applicable cure period), the *Party* must:

a. immediately after becoming aware of the circumstances, give the other *Party* notice of that circumstance; and

b. keep the other *Party* informed both at reasonable intervals and upon request by the other *Party*, as soon as practicable following the receipt of that request, of:

i. the first *Party*'s estimate of the likely duration of the *default*;

ii. the cessation of that *default* or the successful mitigation or minimization of the effects of that *default*; and

iii. any other matter which the other *Party* may reasonably request in connection with the occurrence of the *default* and the matters referred to in paragraphs (b) (i) and (ii).

9.14.2 **Notice by *Party* not in Breach:** If a *Party* becomes aware that a circumstance has arisen which that *Party* reasonably considers constitutes or is likely to constitute or result in a *default* by the other *Party* (for greater certainty, without reference to the applicable cure period), then the first *Party* may give the other *Party* notice of that circumstance. Upon receipt of that notice, the other *Party* must keep the first *Party* informed in accordance with clause 9.14.1(b).

9.14.3 **Cure of *Default*:** Upon receiving notice under clause 9.14.2 or otherwise becoming aware that a circumstance has arisen which constitutes or is likely to constitute or result in a *default* by it (for greater certainty, without reference to the applicable cure period), a *Party* must cure the *default* or prevent the *default* from occurring (as the case requires) and mitigate any loss the other *Party* suffers or is likely to suffer.

9.14.4 **Remedies:** If the defaulting *Party* does not cure a pending *default* within the applicable cure period such that a *default* has occurred, then the non-defaulting *Party* may terminate this *Agreement* by giving a further written notice to the defaulting *Party* which notice shall specify the effective date of termination, and the defaulting *Party* shall forfeit any payment otherwise payable to that *Party* after the termination date as liquidated damages and not as a penalty. If such termination occurs as a result of the *IESO's default*, the *IESO* shall reimburse the *Physical Service Provider* for its *termination costs*.

9.15 **Entire *Agreement*:** This *Agreement* constitutes the entire agreement between the *Parties* with respect to the matters contemplated by this *Agreement* and supersedes all prior agreements, undertakings, negotiations and discussions, whether oral or written, of the *Parties*.

9.16 **Publication or Announcement of Schedules to *Agreement*:** Subject, where applicable, to Article 6, except to the extent otherwise required by *applicable law* or as directed by any *governmental authority* or with the prior written consent of the other *Party*, neither *Party* shall publish in any medium, or make any public announcement concerning the substance of, the Schedules to this *Agreement*.

9.17 ***OEB* Approval:** The *Parties* agree that notwithstanding the proposed *effective date*, this *Agreement* shall not be implemented and no rights or obligations shall accrue hereunder until this *Agreement* is approved by the *Ontario Energy Board*. Notwithstanding anything else in this *Agreement*, if this *Agreement* is approved by the *Ontario Energy Board* after January 1, 2013, the *IESO* shall pay to the *Physical Service Provider* any invoices accrued and payable hereunder since January 1, 2013, in accordance with the terms of Section 4 of Schedule A.

9.18 **Schedules:** The following schedules are attached and shall form part of this *Agreement*:

Schedule A – Settlement and Payments

Schedule B – Performance Standards

Schedule C – *Company Representatives* for Notifications

Schedule D – Variable Costs of Generation, *Reliability Must-Run Payment*, *Monthly Fixed Payment*, *Net Revenue Sharing Adjustment*, *IESO Market Costs*, and *Settlement Amounts*

Schedule E - Fuel Management at *Reliability must-run facility*/Notice of Intent for *Reliability must-run facility*

Schedule F – Form of Confidentiality Agreement

IN WITNESS WHEREOF the *Parties* have, by their duly appointed *representatives*, executed this *Agreement*.

ONTARIO POWER GENERATION INC.

By: [signature]

Name: Tom Mitchell

Title: President & CEO

Date: 6 Feb 2013

ONTARIO POWER GENERATION INC.
approved as to content
name
department
date
name
department
date FEB. 5, 2013
approved as to legal form
solicitor
date Feb 1, 2013

INDEPENDENT ELECTRICITY SYSTEM OPERATOR

By: K. Warren

Name: Kim Warren

Title: Chief Operating Officer

Date: Feb 15/13

SCHEDULE A
SETTLEMENT & PAYMENTS

1. Additional Market Participation Provisions

In addition to the *Physical Service Provider's* obligations set out in Section 3.3 of this *Agreement*, the *Physical Service Provider* shall, in respect of the *reliability must-run facility*:

a. offer in real time and day-ahead as required by the *market rules* the maximum available amount of each category of *energy*, *operating reserve* and, as applicable, any *future facility-related products* in the *IESO-administered markets*, consistent with *good utility practices*;

b. participate in markets other than the *IESO-administered markets* for *future facility-related products* consistent with *good utility practices* and acting commercially reasonably; and

c. make such *facility* available if that *facility* is physically capable of responding to *dispatch instructions*, consistent with *good utility practices*.

2. *Settlement Amounts and Invoicing*

a. Settlement of this *Agreement* will follow the physical market settlement calendar as published by the *IESO*;

b. Due to the timing of the settlement cycle, the various components of the settlement amount will appear as follows:

   i. The *monthly fixed payment* as specified in Schedule D will appear on the *invoice* for the calendar month; and

   ii. The *market costs* as specified in Schedule D for a calendar month will appear on the *invoice* issued for the next calendar month.

   iii. The *net revenue sharing adjustment* and the *auxiliary boiler fuel* costs and any *regulatory testing* costs will be settled on a quarterly basis over the *term* with the settlement included on the *invoice* for the second month after the quarters defined as

   January 1, 2013 to March 31, 2013

   April 1, 2013 to June 30, 2013

   July 1, 2013 to September 30, 2013, and

   October 1, 2013 to December 31, 2013

c. the *IESO* shall separately provide the *Physical Service Provider* with a *settlement* schedule for this *Agreement* setting forth timelines associated with the *settlement* of amounts owing under this *Agreement* including provision relating to the *Physical Service Provider's* obligation to submit to the *IESO* the *actual cost of fuel* associated with the operation of the *reliability must-run facility*.

3. *Early Termination Payment*

a. Upon the *IESO's* early termination of this *Agreement* pursuant to Section 7.3 of this *Agreement* or an early termination of this *Agreement* by the *Physical Service Provider* pursuant to Section 9.14 of this *Agreement* as a result of the *IESO's default*, the *IESO* shall pay to the *Physical Service* Provider its *termination costs.*

b. The procedure for the calculation and payment of the *termination costs* shall be as follows:

i. Within sixty (60) days of the date of any termination pursuant to subsection 3(a), the *Physical Service Provider* shall prepare and deliver to the *IESO* a *termination costs statement* calculating in detail the *termination costs* to be received by the *Physical Service Provider*, and shall provide to the *IESO* detailed financial statements and all calculations and values used to determine or which support the calculation of the *termination costs* and any other evidence reasonably requested by the *IESO* in support of the *termination costs.*

ii. Within thirty (30) days of receipt of the *termination costs statement,* the *IESO* shall review the *termination costs statement* and, to the extent it disputes any matter with respect to such statement, including the *termination costs* amount, the *Parties* agree that only the undisputed amount shall be paid pending resolution of the dispute.

iii. The *Physical Service Provider* shall include the undisputed portion, if any, of the *termination costs* in an amended *termination cost statement* to be delivered in the next month immediately following the month in which the *IESO* completes its review of the *termination costs statement*, and such amount, if any, shall be paid by the *IESO* within thirty (30) days of receipt of such amended *termination cost statement*.

4. Payments Prior to OEB Approval

Notwithstanding anything else in this *Agreement,* since this *Agreement* cannot be approved by the Ontario Energy Board until after January 1, 2013 with respect to any payments accrued and payable prior to such approval, the following shall apply:

a. The *Physical Service Provider* shall within fifteen (15) *business days* of approval of this *Agreement* prepare and deliver to the IESO an invoice for *settlement amounts* payable to the *Physical Service Provider* prior to the date of such approval of this *Agreement*. The total of such *settlement amounts* shall be the *accrued settlement amounts*. The *accrued settlement amounts* shall be calculated as follows:

1) *Monthly fixed payments* for the months up to the month prior to the month this *Agreement* is approved

2) *Market costs* for the months up to the month two months prior to the month this *Agreement* is approved

3) *Net revenue sharing adjustment* amounts and *regulatory testing* costs and *auxiliary boiler fuel* costs for the quarter as defined in section 2(b)(iii) of this Schedule that ended at least 2 months prior to the month the contract was approved

b. The *accrued settlement amounts* shall be paid over the remaining *term* of the *Agreement* by dividing the *accrued settlement amounts* by the number of months remaining to be invoiced, and the IESO shall pay that amount (the *monthly accrued payment*) to the *Physical Service Provider* at the same time such remaining invoices are paid. The first *monthly accrued payment* and the *settlement amount* for the previous month shall be paid by the *IESO* to the *Physical Service Provider* without interest on the *accrued settlement amount.* On each subsequent payment date, the *IESO* shall pay the *Physical Service Provider* the *monthly accrued payment,* the *settlement amount* and interest on the unpaid portion of the *accrued settlement amount.* For the first interest payment, the amount of interest owing shall be calculated as follows: (Unpaid portion of the *accrued settlement amount)* × (the *interest rate)* × [(the number of days from the payment date of the first *monthly accrued payment* to the payment date of the subsequent *monthly accrued payment*) ÷ (number of days in the year)]. For each following interest payment, the amount of interest owing shall be calculated as follows: (Unpaid portion of the *accrued settlement amount)* × (the *interest rate)* × [(number of days from the previous payment date of the *monthly accrued payment* to the payment date of the subsequent *monthly accrued payment*)].

SCHEDULE B
PERFORMANCE STANDARDS

1. Definition and Calculation of *EFOR – OP*

The *penalty* or *reward* (each as defined in Section 3 below) payable by the relevant *Party* pursuant to this Schedule B shall be calculated with reference to the difference between the *reliability must-run facility'* actual *EFOR – OP* and the *EFOR - OP target*, each as described below.

"*EFOR – OP*" is a measure of a generating unit or station's reliability when it is required to operate. It is a measure of the percentage of total "exposure" time represented by "forced" occurrences. *EFOR - OP* includes Operating Time and ABNO (Available But Not Operating). The *EFOR - OP* metric is similar to the measure Equivalent *Forced Outage* Rate (EFOR) except that it accounts for ABNO and Available But Not Staffed (ABNS) in the metric's denominator.

EFOR – OP shall be calculated as follows:

$$EFOR(OP) = \frac{\sum_{Units}\left\{\sum_{EFOR(OP)\_N\_States} MCR * Duration\right\}}{\sum_{Units}\left\{\sum_{EFOR(OP)\_D\_States} MCR * Duration\right\}} * 100$$

Where:

EFOR_N_States =
FO1, FO2, FO3, FOT,
SO, SOT,
FEMO, FEPO,
EO_FD, ESCC_FD,
EABNO_FD, EABNS_FD,

EFOR_D_States =
O, O_FD, O_SD, O_GD,
SCC, SCC_FD, SCC_SD, SCC_GD,
FO1, FO2, FO3, FOT,
SO, SOT,
FEMO, FEPO,
ABNO , ABNO_FD, ABNO_SD, ABNO_GD,
ABNS, ABNS_FD, ABNS_SD, ABNS_GD

Definitions:

State Code	Full Name
ABNO	Available but Not Operating
ABNO_FD	Available but Not Operating-Forced Derated
ABNO_GD	Available but Not Operating-Grid Derated
ABNO_SD	Available but Not Operating-Scheduled Derated
ABNS	Available but Not Staffed
ABNS_FD	Available but Not Staffed - Forced Derated
ABNS_GD	Available but Not Staffed - Grid Derated
ABNS_SD	Available but Not Staffed - Scheduled Derated
EO_FD	Equiv. Operating Forced Derated
ESCC_FD	Equiv. Synch. Condenser Forced Derated
EABNO_FD	Equiv. ABNO Force Derated
EABNS_FD	Equiv. ABNS Force Derated
FEMO	Forced Extension of Maintenance Outage
FEPO	Forced Extension of Planned Outage
FO1	Forced Outage class 1 < 10 min notice
FO2	Forced Outage class 2 > 10 min <6 hour notice
FO3	Forced Outage class 3 >6 hour notice
FOT	Forced Outage Trip
O	Operating
O_FD	Operating Forced Derated
O_GD	Operating Grid Derated
O_SD	Operating Scheduled Derated
SCC	Synchronous Condenser Operation
SCC_FD	Synchronous Condenser Operation - Forced
SCC_GD	Synchronous Condenser Operation - Grid Derated
SCC_SD	Synchronous Condenser Operation – Scheduled Derated
SO	Sudden Outage (>25% Unit MCR)
SOT	Sudden Outage (> 25% Unit MCR) – Tripped

and

MCR means *maximum continuous rating*.

2. *EFOR - OP Targets*

The *Physical Service Provider* shall maintain, consistent with *good utility practices*, an *EFOR – OP* of between 6.0% and 10.0[73]% throughout the *term*.

3. *Penalties* or *Rewards* for Not Meeting or Exceeding the *EFOR - OP Target*

The calculation of the *penalty* or *reward* that shall apply where the *EFOR - OP target* is not met or is exceeded shall be completed as follows:

- The actual *EFOR - OP* shall be calculated for the *term*.
- A penalty (a "*penalty*") or reward (a "*reward*") shall be calculated with reference to the *EFOR - OP target* and the actual *EFOR - OP* for the *term* as described below.
- Performance shall be measured by the application of performance points (each a "*performance point*"), with *performance points* calculated as the percentage number by which the actual *EFOR – OP* was below or above the *EFOR - OP term*, calculated to the first decimal place.
- For purposes of calculating a *penalty* or *reward* for the *term*, each *performance point* shall be valued at $ 0.17 million.
- Upon the expiration or termination of this *Agreement*, the total net *penalty* or *reward* payable shall be calculated (the *"net penalty/reward"*), and shall be paid following such expiration or termination as set out in Section 4 below.
- The total net *penalty* or *reward* payable shall not exceed $0.5 million.
- No *penalty* or *reward* shall be calculated or applicable during, and no *net penalty/reward* shall be payable in respect of, any period in which the *Physical Service Provider* is experiencing a *force majeure event*.

For illustration purposes only, the following examples demonstrate the application of the foregoing calculations:

Example 1

- Value of each *performance point*: $0.17 M.
- Index calculated for the *term*:
  - *EFOR – OP*: 3.0% (3.0 *performance points* below the *EFOR - OP target*)
  - *Reward*: 3.0*$0.17M = $0.51M, limited to $0.50M

Example 2

- Value each *performance point*: $0.17M.
- Index calculated for the *term*:
  - o *EFOR – OP*: 11.8% (1.8 *performance points* above the *EFOR - OP target*)
  - o *Penalty*: 1.8 * $0.17M = $0.31 M

4. Procedures for Calculation of the *Net Penalty/Reward*

The procedure for the calculation and payment of the *net penalty/reward* shall be as follows:

a. Within thirty (30) days of the expiration or termination of the *Agreement*, the *Physical Service Provider* shall prepare and provide to the *IESO* the *EFOR – OP* for the *term* and shall provide to the *IESO* all calculations and values used to determine or which support the calculation of such *EFOR - OP* and any other evidence reasonably requested by the *IESO* in support thereof.

b. Within fifteen (15) days of receipt of the foregoing, the *IESO* shall review the foregoing information provided by the *Physical Service Provider* and shall calculate the *net penalty/reward* (the "*net penalty/reward statement*") and the amount of the payment owing by the relevant *Party*, and shall provide to the *Physical Service Provider* its calculations used to determine the *net penalty/reward* and the amount owing.

c. Within ten (10) days of receipt of the *net penalty/reward statement,* the *Physical Service Provider* shall review the *net penalty/reward statement.*

d. The *IESO* shall include the undisputed portion, if any, of the *net penalty/reward* in the *Physical Service Provider*'s *invoice* and *settlement statements* for the next month immediately following the month in which the *Physical Service Provider* completes its review of the *net penalty/reward statement*, and such amount, if any, shall be paid by the relevant *Party* in accordance with Section 8.1 of this *Agreement.*

SCHEDULE C

COMPANY REPRESENTATIVES FOR NOTIFICATIONS

Name of *IESO* Representative:	Nicholas Ingman
Title:	Manager, Operational Excellence
Address:	Suite 410, 655 Bay Street
City/Province/Postal Code	Toronto, Ontario, M5G 2K4
Email address:	nicholas.ingman@ieso.ca
Phone:	(905) 855-6108
Fax:	(905) 855-6129

Name of *Physical Service Provider* Representative:	Ken Lacivita
Title:	Director, Trading and Origination
Address:	700 University Avenue - H9D18
City/Province/Postal Code	Toronto, Ontario, M5G 1X6
Email address:	k.lacivita@opg.com
Phone:	(416) 592-5585
Fax:	(416) 592-7584

SCHEDULE D

VARIABLE COSTS OF GENERATION, RELIABILITY MUST-RUN PAYMENT, MONTHLY FIXED PAYMENT, NET REVENUE SHARING ADJUSTMENT, IESO MARKET COSTS, AND SETTLEMENT AMOUNT

1. Variable Costs of Generation

The *Physical Service Provider* will not be compensated by this *Agreement* for the variable costs associated with generating electricity from the *reliability must-run facility* other than those set forth in Schedule D, Sections 2, 3 and 4.

2. Market Costs

The *Physical Service Provider* shall be reimbursed for *market costs.*

3. Auxiliary Boiler Fuel

The *Physical Service Provider* shall be reimbursed for its *auxiliary boiler fuel* as submitted to the *IESO.*

4. Fuel Used for Regulatory Testing

To the extent possible, the *Physical Service Provider* shall schedule its *regulatory testing* during periods the *reliability must-run facility* are expected to run. If the period in which the tests are performed has an *NRSA* of zero the *Physical Service Provider* may not have recovered its *actual cost of fuel.* In such event, the *Physical Service Provider* shall submit to the *IESO* the information associated with any required *regulatory testing* including the specific date and duration of the test and the *actual cost of fuel* used during each day of the test. The *IESO* shall evaluate the provided costs for the test and compare that to the *market revenues* earned by the *Physical Service Provider* during the testing period. If the *market revenues* are less than the *actual cost of fuel* used in each day of the test, the *IESO* shall reimburse the *Physical Service Provider* the shortfall amount.

5. Monthly Fixed Payment (MFP)

The IESO shall reimburse the *Physical Service Provider* on a monthly basis for the *monthly fixed payment* as identified in Table 1:

Schedule D Table 1: Monthly Fixed Payment ("MFP") for Thunder Bay Generating Station (TBGS) G3 (the *reliability must-run facility*)

Cost Category $k	TBGS G3
OM&A Costs	
Labour	17,311
Direct Assigned[1]	5,752
Business Unit Support - Direct[2]	404
Central Support - BU Allocated[3]	5,258
Materials	1,224
Other[4]	4,330
Projects[5]	970
Insurance	795
Property Taxes	1,660
Other Costs	
Financing Cost on Working Capital[6]	267
Monthly Fixed Payment ("MFP") - Annualized	**37,971**
Monthly Fixed Payment ("MFP")	**3,164**

NOTES:

[1] Labour-related costs such as Pension, Other Post Employment Benefits, Incentives and Vacation Accrual

[2] Central Thermal staff and related costs servicing the RMR Facility such as Machine Dynamics and Performance & Testing that are avoidable within a relatively short term following unit closure

[3] Corporate support costs servicing the RMR Facility such as IT, Finance, Energy Markets and Human Resources that are avoidable within a relatively short term following unit closure

[4] Principal elements are contracted external purchased services for both planned outage and base maintenance, specialized technical services, surveys, other contractors, leasing costs for fleet equipment; employee expenses for contractual obligations (overtime meals, relocation due to internal transfers), training and related travel costs, recruitment costs; inventory obsolescence costs; water and telephone bills; safety and environmental testing, monitoring and audit; TSSA licensing fees, office supplies and other such costs.

[5] Includes costs for non-routine maintenance, repairs and replacements managed on a project specific basis. All expenditures on equipment are expensed in the year incurred in accordance with generally accepted accounting principles. Major projects at Thunder Bay GS include U3 Waterwall sootblower opening cracking, Treatment Boiler Makeup Water/Gas Exchange Membrane and U1 Electrical Reconfiguration.

[6] Working capital financing on material/supply and fuel inventory based on monthly ending balances at 6% per annum.

6. Net Revenue Sharing Adjustment ("NRSA")

The *Physical Service Provider* shall pay the *IESO* a *net revenue sharing adjustment (NRSA)* if applicable.

The *NRSA* is defined as:

NRSA = Max (0, (∑*Market Revenues* + ∑*non-IESO market revenues* – ∑*actual cost of fuel*) *(distribution factor)

The distribution factor shall be 0.95, except in those circumstances set forth in section 6 of Schedule E.

For greater clarity, NRSA shall be determined quarterly, as such quarters are defined in Section 2 b. iii of Schedule A. *Market revenue*, *non-IESO market revenue*, and *actual cost of fuel* shall each be the summation of such amounts over the quarter. NRSA will not increase amounts paid to the *Physical Service Provider*.

7. Settlement

Settlement and payment of all the items referred to in Sections 2 to 6 of this Schedule D shall occur in accordance with terms of Schedule A.

SCHEDULE E

FUEL MANAGEMENT AT RELIABILITY MUST RUN FACILITY/NOTICE OF INTENT FOR RELIABILITY MUST-RUN FACILITY

Fuel Management at *Reliability must-run facility*

1. The *Physical Service Provider* will offer the *reliability must-run facility* in such a way as to manage its limited fuel supplies in order to meet *IESO's reliability* needs and minimize its stranded fuel costs at the termination of this *Agreement.*

2. In all situations, other than those set out in Sections 4 - 9 of this Schedule the *Physical Service Provider* will be responsible for the *disposal cost* of coal at the termination of this *Agreement.*

3. No later than 5 business days after the end of each month during the *term* the *Physical Service Provider* will submit to the *IESO* (i) the estimated fuel usage (in GWh), (ii) the estimated remaining fuel inventory (in GWh) and (iii) the estimated usable coal inventory, seasonally adjusted, in GWh for the *reliability must-run facility.*

4. Based on the information provided in accordance with section 3. of this Schedule, the *IESO* is authorized to direct the *Physical Service Provider to* curtail the use of coal and to retain the *required coal* at the *reliability must-run facility* through a declaration that the *reliability must-run facility* is considered to be *energy*-limited when the *IESO* assesses that the estimated usable coal is insufficient to manage the forecasted *reliability* requirements.

5. The *IESO* will issue the direction set out in Section 4 of this Schedule in writing to the *Physical Service Provider* within 7 *business days* of receipt of the fuel management information set out in section 3 above, including any consultation with the *Physical Services Provider* as required.

6. If the *IESO* has issued a direction as set out in Section 4 of this Schedule the *Physical Services Provider* will only operate the *reliability must-run facility* as *energy*-limited resources by offering the *facility* at *maximum market clearing price* through either the day-ahead or real-time scheduling options. When the *energy*-limited resources *facility* is required to run for *reliability* purposes the *Physical Services Provider* shall adjust their *offer prices* to reflect the *Physical Service Provider's* best estimate of the *actual cost of fuel* and any other related costs. During the time period that the direction is effective there shall be a separate *NRSA* calculation for the *reliability must-run facility* affected by such direction and the *NRSA* distribution factor will be set to 1.0-for such facility for such period. This *NRSA* shall be added to the *NRSA* as determined on a quarterly basis pursuant to Section 6 of Schedule D.

7. In addition, the *IESO* shall be authorized after issuing the direction set out in Section 4 of this Schedule, to direct the *Physical Service Provider* to purchase additional coal if, through consultation with the *Physical Service Provider* and taking into consideration the applicable fuel

delivery timeframes, it is determined that the remaining fuel is insufficient to meet *IESO's reliability* needs.

8. If the *IESO* has issued a direction in accordance with Section 4 or 7 of this Schedule and the *Parties* do not enter into a new reliability must run contract with respect to the *reliability must-run facility,* the *IESO* shall pay the *disposal costs* of any such *required coal* or purchased additional coal which remains at the termination of this *Agreement.*

9. In accordance with section 8 the *IESO* shall be responsible for any costs associated with the disposition of any amounts of *required coal* or purchased additional coal remaining at the termination of this *Agreement.* Since the *IESO* is responsible for such *disposal costs,* the *Parties* shall open up this *Agreement* for further negotiations at the request of the *IESO* on both the proposed *disposal costs* and on any strategies associated with the potential use of that coal by the *Physical Service Provider* in the *IESO-administered markets.*

Notice of Intent for *Reliability must-run facility*

10. The *Physical Services Provider* shall notify the *IESO* no later than September 1, 2013 via a de-registration request if the *Physical Services Provider* wishes to de-register the *reliability must-run facility* upon the termination date of this *Agreement.*

11. The *IESO* shall, in accordance with the *market rules*, conduct a formal study of the de-registration request. If the *IESO* determines through its formal assessment of the de-registration request that the *reliability must-run facility* is no longer required after the termination date of this *Agreement* for the purposes of maintaining the *reliable* operation of the *IESO-controlled grid* the *IESO* shall inform the *Physical Services Provider.* In the event that the *reliability must-run facility* has been declared as *energy*-limited the *Physical Services Provider* will be permitted to start drawing down their coal supplies through *offers* submitted into the *IESO-administered markets* for the purpose of minimizing the disposal costs

12. If t*he IESO* determines that *the reliability must-run facility* will need to remain in service for *reliability* reasons after the termination of this *Agreement* the *IESO* shall direct the *Physical Services Provider to continue to manage* the *required coal* for *reliability* purposes and will initiate negotiations on a subsequent *reliability must-run contract* with the *Physical Services Provider.*

SCHEDULE F
FORM OF *CONFIDENTIALITY AGREEMENT*

CONFIDENTIALITY AGREEMENT

THIS ***AGREEMENT*** *made as of*

***BETWEEN*:**

(hereinafter referred to as "**Auditor**")

OF THE FIRST PART

- *and* –

ONTARIO POWER GENERATION INC.,
a corporation incorporated under the laws
of the Province of Ontario

(*hereinafter referred to as* "**OPG**")

OF THE SECOND PART

WHEREAS the Independent Electricity System Operator ("*IESO*") has appointed the Auditor to review certain books, records, data, procedures and operations of OPG pursuant to a Reliability Must-Run Agreement (the "RMR Agreement") dated as of January 1, 2013 in respect of the Thunder Bay Generating Station between the *IESO* and OPG, for purposes of verifying OPG's compliance with its obligations under that *Agreement* and discussing the results of its audit with, and reporting thereon to, the *IESO* (an "Audit").`

AND WHEREAS OPG has and will be furnishing, disclosing or otherwise making available for inspection and review by the Auditor certain information (including without limitation, pricing information under supply contracts, financial, technical, operational, commercial, staff, management and other information, data, experience and knowledge relating to the Thunder Bay Generating Station by oral, electronic, written and other forms of communication including, without limitation, demonstrations and information by chart, diagram, models, computer programs, or other tangible form, which information is either non-public, confidential or proprietary in nature. This information furnished by OPG, together with analyses, compilations, forecasts, studies or other documents prepared by the Auditor which contain or otherwise reflect such information, is hereinafter referred to collectively as the "*confidential information*".

AND WHEREAS it is the intention of the *Parties* hereto that the terms, conditions and restrictions of this Confidentiality Agreement shall be construed so as to be given the broadest application and effect and, to the extent that the context permits, the terms "OPG" and "Auditor" shall for all purposes be deemed to include their respective agents, representatives (including lawyers, engineers, accountants, consultants, and other professional or financial advisors), employees, partners, and including without limitation all individuals, organizations or entities (collectively, "representatives") that either *Party* may use to assist it for purposes of the Audit and who may be shown or have described to them *confidential information*.

NOW THEREFORE in consideration of OPG's furnishing, disclosing or otherwise making available for inspection and review by the Auditor *confidential information*, and other good and valuable consideration the receipt and sufficiency of which is hereby acknowledged, the *Parties* covenant and agree that:

1. OPG will be furnishing, disclosing or otherwise making available for inspection and review by the Auditor *confidential information* for purposes of the Audit.

2. Notwithstanding any term in this Confidentiality Agreement, the Auditor may disclose to the *IESO* information that is reasonably required by the *IESO* for the Audit provided that:

   i. such disclosure will not cause OPG to breach any of its confidentiality requirements (including, without limitation, confidentiality requirements in its supply contracts); and

   ii. information about any of OPG's *facility* or businesses other than Thunder Bay Generating Station is not contained in such disclosure.

3. Without the prior written consent of OPG, except as required by *applicable law* and as permitted by Sections 2 and 6 of this *Agreement*, the Auditor shall not disclose any *confidential information* received in any manner whatsoever, in whole or in part, and such information shall not be used by the Auditor other than for purposes of the Audit. The Auditor acknowledges that the *confidential information* referred to in this Confidentiality Agreement is confidential and proprietary to OPG, is supplied in confidence, and for the purposes of this Confidentiality Agreement the Auditor does not dispute that disclosure of this information would prejudice significantly the competitive position of OPG.

4. Save and except for notes made by the Auditor during its inspection and review of the *confidential information*, the Auditor shall not make any copies or reproductions of the *confidential information* in any medium or form other than as reasonably necessary for purposes of the Audit.

5. Notwithstanding the disclosure of *confidential information* to the Auditor, the *confidential information* shall remain the sole and exclusive property of OPG. OPG does not waive its right to maintain the *confidential information* in confidence, and to avail itself of any and all remedies available at law to maintain such information in confidence.

6. The Auditor shall only disclose the *confidential information* to:

   i. such of its representatives who need to know the *confidential information* for the purposes of the Audit and only if the representatives have agreed to be bound by the terms of this Confidentiality Agreement; and

   ii. the Canadian Public Accountability Board if so requested by that board for purposes of its oversight responsibility for audit firms.

   The Auditor hereby specifically acknowledges that it shall be solely responsible to ensure that the representatives are bound by the terms of this Confidentiality Agreement and that the Auditor shall defend, indemnify and hold harmless OPG from and against all suits, actions, damages, claims and costs arising out of any breach of this Confidentiality Agreement by the *representatives*.

7. At all times, and at a minimum, the Auditor will take the same precautions to protect the *confidential information* that it takes to protect its own proprietary and *confidential information*. The Auditor will take all reasonable steps and precautions to prevent the unauthorized disclosure of the *confidential information* or the unauthorized use of the *confidential information* for any purpose not expressly allowed herein.

8. Upon OPG's request, or on the expiry of the RMR Agreement, and subject to:

   i the survival period specified in Section 7.5 thereunder; and

   ii the Auditor's record retention policy:

   the Auditor shall promptly:

   a. return or destroy all *confidential information* disclosed or otherwise obtained in writing or recorded in any medium or form, including all copies or reproductions thereof, and will certify to OPG that it has done so;

   b. where not included in the *confidential information* to be retained by OPG, destroy all analyses, compilations, forecasts, studies or other documents disclosed to or otherwise obtained in writing or recorded in any form, including all copies or reproductions thereof, other than any analyses, compilations, forecasts, studies or other documents prepared by the Auditor which contain *confidential information*, and will certify to OPG that it has done so: and

c. where not included in the *confidential information* to be returned to OPG, permanently erase and remove all *confidential information* from hard drives, taped back ups, and any other medium or form from which the *confidential information* could be recovered so that such *confidential information* cannot be recovered by any means, and will certify to OPG in writing that it has done so.

9. The Auditor agrees to provide immediate notice to OPG of any breach of this Confidentiality Agreement or misappropriation of the *confidential information* upon becoming aware of such breach.

10. In the event that the Auditor, or anyone to whom the Auditor transmits *confidential information* pursuant to this Confidentiality Agreement or otherwise, becomes legally compelled to disclose any *confidential information*, the Auditor will provide OPG with prompt notice so that OPG may seek injunctive relief or other appropriate remedies and/or waive compliance with the provision of this Confidentiality Agreement. Furthermore, the Auditor will exercise all reasonable efforts to prohibit the further transmission of the *confidential information*, including reasonable efforts to assist OPG to contest and resist such disclosure. In the event that both *Parties* are unable to prevent the further transmission of the *confidential information*, the Auditor will use reasonable efforts to obtain assurances that confidential treatment will be afforded to that portion of the *confidential information* furnished.

11. For the purposes of this Confidentiality Agreement the Auditor does not dispute that OPG would be irreparably injured by a breach of this Confidentiality Agreement and would be entitled to equitable relief, including injunctive relief and specific performance as may be granted by any court of competent jurisdiction to prevent breaches of this Confidentiality Agreement and to enforce specifically the terms and provisions hereof in any action instituted in any court having subject matter jurisdiction.

12. The restrictions set forth herein shall not apply to the *confidential information* if it:

a. was previously known to or lawfully in the possession of the Auditor prior to being furnished, disclosed or otherwise made available to the Auditor;

b. is or has become public knowledge, by publication or otherwise, through no fault or breach of this *Agreement* on the part of the Auditor or its *representatives*;

c. is or becomes available to the Auditor on a non-confidential basis from another source other than OPG, provided that such source is not known by the Auditor to be subject to a confidentiality obligation with respect to such information; or

d. is developed by the Auditor entirely independent of and without reference to the *confidential information*.

13. This Confidentiality Agreement shall be binding upon the Auditor and its respective successors and assigns. The Auditor may not assign or otherwise transfer in whole or in part this Confidentiality Agreement or rights or obligations hereunder without the prior written consent to such assignment or transfer by OPG. Any such attempted assignment or transfer without written consent shall be void and of no force and effect.

14. This Confidentiality Agreement shall be governed by and construed in accordance with the laws of the Province of Ontario and the laws of Canada applicable therein. The *Parties* attorn to the exclusive jurisdiction of the courts of the Province of Ontario with respect to any suit, action, application or proceeding relating to this Confidentiality Agreement ("Proceedings"), and waive any objection which they may have at any time to this venue, and hereby waive any claim that such Proceedings have been brought in an inconvenient forum and further waive the right to object with respect to such Proceedings that such courts do not have jurisdiction over the *Parties*.

15. If any provision of this Confidentiality Agreement shall be held, declared or pronounced void, voidable, invalid, unenforceable or inoperative for any reason by any court of competent jurisdiction, government authority or otherwise, such holding, declaration or pronouncement shall not affect adversely any other provision of this Confidentiality Agreement which shall otherwise remain in full force and effect and be enforced in accordance with its terms and the effect of such holding, declaration or pronouncement shall be limited to the territory or jurisdiction in which made.

16. All the rights and remedies of OPG under this Confidentiality Agreement are cumulative and not exclusive of any other rights and remedies provided by law. No delay or failure on the part of OPG in the exercise of any right or remedy arising from a breach of this Confidentiality Agreement shall operate as a waiver of any subsequent right or remedy arising from a subsequent breach of this Confidentiality Agreement. The consent of OPG where required hereunder to any act or occurrence shall not be deemed to be a consent to any other act or occurrence.

17. The *Parties* hereby acknowledge and agree that this Confidentiality Agreement does not create a partnership, joint venture or any other relationship between the *Parties*.

18. This Confidentiality Agreement contains the whole agreement between the *Parties* relating to the subject matter of this Confidentiality Agreement and shall supersede any and all promises, representations, warranties, undertakings or other statements whether written or oral made by or on behalf of the one *Party* to the other *Party* of any nature whatsoever or contained in any document given by one *Party* to the other.

19. This Confidentiality Agreement may only be amended by mutual agreement, in writing, of the *Parties* hereto.

20. The Confidentiality Agreement shall come into force on the date first shown above and shall remain in force until three years from the date of the last audit performed by the Auditor under this Confidentiality Agreement.

21. Unless otherwise provided herein, every notice provided for this Confidentiality Agreement shall be in writing to the *Party* to whom given, made or delivered at such *Party's* address, either personally or by registered and prepaid mail or by facsimile as follows:

to the Auditor at:

Attention:

Telephone:
Facsimile:

to OPG at:

Ontario Power Generation Inc.
700 University Avenue H9D18
Toronto, ON M5G 1X6

Attention: Mr. Ken Lacivita
Director, Trading and Origination

Telephone: (416) 592-5585
Facsimile: (416) 592-7932

Either *Party* may change its address for service of notice from time to time by giving notice of such change to the other *Party* in the manner provided for herein. Any notice made, given or delivered under this Confidentiality Agreement shall be in writing and shall be served on the relevant *Party* hereto by delivering the notice by hand, sending it by facsimile transmission or by first class post (recorded delivery) addressed to the relevant *Party* at its address set out above or to such other address as that *Party* may have changed as set out herein. Any such notice shall be deemed to have been validly served, if delivered by hand on delivery, or five (5) days after posting by first class (recorded delivery) mail, or if transmitted prior to 4:00 P.M. Eastern Standard Time on the date of transmission in the case of facsimile transmission provided such day is a *business day*, or the first *business day* thereafter if transmitted after 4:00 P.M. Eastern Standard Time, or in the event such day was not a *business day*.

IN WITNESS WHEREOF the *Parties* have caused this Confidentiality Agreement to be executed by their proper officers duly authorized in that behalf as of the date and year first written above.

ONTARIO POWER GENERATION INC.	**[Auditor]**
By: ______________________	By: ______________________
Name: ______________________	Name: ______________________
Title: ______________________	Title: ______________________
I have authority to bind the Corporation	I have authority to bind the Corporation

Attachment 2

ONTARIO POWER GENERATION

Colin Anderson
Director

Ontario Regulatory Affairs

700 University Avenue, Toronto, ON M5G 1X6

Tel: 416-592-3326 Fax: 416-592-8519
colin.anderson@opg.com

November 15, 2012

VIA EMAIL

Mr. Bruce Campbell
Vice President – Resource Integration
Independent Electricity System Operator
655 Bay Street, Suite 410
Toronto, ON M5G 2K4

Re: Notice of Request to De-register the Thunder Bay Generation Facilities

Dear Mr. Campbell:

Further to my letter of November 9, 2012, pursuant to Chapter 7, Section 2.4 of the Market Rules, Ontario Power Generation (OPG) hereby gives Notice of Request to De-register all generation facilities at the Thunder Bay generation station. This facility has a net in-service capacity of 306 MW.

OPG is seeking de-registration of the facilities at the earliest opportunity available under the Market Rules, or in the event that the IESO assessment determines that these facilities are required for local reliability reasons, to enter into a Reliability Must Run (RMR) agreement.

OPG requests that the IESO treat this Notice of Request to De-register as confidential until the IESO assessment process is complete.

Background

The revenue earned by these facilities from the wholesale electricity market has not been sufficient to cover the station's costs. Looking forward, OPG does not expect that this situation will change. Given our commitment to cost control, OPG cannot continue to operate this station at a loss.

Next Steps

OPG is prepared to negotiate a Reliability Must Run (RMR) agreement for the facility, if the IESO determines, in accordance with the Market Rules, that such an agreement is necessary to support the continued reliability of the IESO-controlled grid.

Alternatively, if the IESO determines that the station can be de-registered, then OPG requests that the IESO provide it with any additional direction necessary to complete the process for de-registration, consistent with Chapter 7, Sections 2.4.1 and 2.4.2 of the Market Rules. In particular, OPG requests that the IESO advise it within 10 business days whether a technical assessment of the impact of de-registration is required. Further, OPG requests that the IESO complete its technical assessment, if one is required, at the earliest possible date within 45 days after the determination that an assessment is required.

Please acknowledge receipt of this request and direct any comments or questions in this matter to the undersigned.

Regards,

Colin Anderson
Director, Ontario Regulatory Affairs
Ontario Power Generation

c: Regulatory Affairs Records, OPG
K. Warren, IESO
B. Constantinescu, IESO
B. Rivard, IESO
R. Marcuzzi, OPG
F. Chiarotto, OPG
B. Boland, OPG

Attachment 3

ieso
Power to Ontario.
On Demand.

Independent Electricity
System Operator
655 Bay Street
Suite 410, PO Box 1
Toronto, Ontario M5G 2K4
t 416 506 2800
www.ieso.ca

January 7, 2013

Mr. Colin Anderson
Director – Ontario Regulatory Affairs
Ontario Power Generation Inc.
700 University Avenue
Toronto, ON M5G 1X6

Dear Mr. Anderson:

Re: Notice of Request to Deregister the Thunder Bay Generation Facility

Further to my letter dated November 29, 2012 the IESO has completed its reliability assessment of your deregistration request for the Thunder Bay generation facility. We have determined that the removal from service of the entire facility for the next year, when Atikokan is out of service for conversion to biomass, would likely have an unacceptable impact on the reliability of the IESO-controlled grid. Accordingly, we are prepared to enter into discussions with a view to concluding a Reliability Must Run (RMR) contract for at least one Thunder Bay unit. This contract would ensure the continued operation of this facility for a period of up to one year.

The IESO Operational Excellence group will contact the OPG Trading & Origination group in this regard.

Yours truly,

Bruce B. Campbell

c: Kim Warren
Nicholas Ingman
Barbara Constantinescu

Bruce B. Campbell
Vice President,
Resource Integration
bruce.campbell@ieso.ca
t 416 506 2829

Public

Technical Assessment

Thunder Bay De-registration

Issue 2.0

Technical Assessment following OPG's request to de-register the Thunder Bay coal fired generation station located in Ontario's Northwest zone

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Document ID	REP-4
Document Name	Thunder Bay De-registration
Issue	2.0
Reason for Issue	OPG's request to de-register Thunder Bay GS
Effective Date	March 1, 2013

Document Change History

Issue	Reason for Issue	Date
1.0	First issue	January 31, 2013
2.0	Changed from confidential to public	March 1, 2013

Executive Summary

OPG filed a notice of request with the IESO on November 15th, 2012, seeking to de-register the Thunder Bay generation facility. This technical assessment was conducted by the IESO to determine whether the removal from service of the facility will or is likely to have an unacceptable impact on the reliability of the IESO-controlled grid during 2013. The facility, comprised of two units, is located in Ontario's Northwest zone and represents a total of 306 MW net installed capacity.

The technical assessment concluded that for the 2013 forecast year, during which Atikokan is out of service for conversion to biomass:

- removing one Thunder Bay unit from service is not likely to have an unacceptable impact on the reliability of the IESO controlled grid, and;
- removing a second Thunder Bay unit from service is likely to have an unacceptable impact on the reliability of the IESO controlled grid.

Following such conclusions, the Market Rules dictate that the IESO enter into negotiations with the registered market participant for a reliability must-run contract. Based on the technical assessment, those negotiations would contemplate a contract with OPG for one Thunder Bay unit to secure the continued availability of the facility for a period of up to one year.

This document sets out the methodology and findings of the IESO's technical assessment. Due to the limited transfer capability into the Northwest zone, as well as the area's dependence on hydroelectric generation, the IESO requires that the reliability assessment criteria be met under lower than normal water conditions.

The technical assessment performed for the 2013 forecast year during which Atikokan is out of service for conversion to biomass, concluded the following:

- Results from the resource adequacy assessment show that one of the two units at Thunder Bay is required to maintain load supply reliability in the Northwest zone such that Ontario's overall supply adequacy is within a loss of load expectation (LOLE) of no more than 0.1 day per year, consistent with Ontario and Northeast Power Coordinating Council criteria. The removal of both of these units from service, without adequate replacement of supply, is likely to result in violation of the resource adequacy assessment criterion.
- Under 90th percentile dependable water conditions, adequacy criteria can be satisfied with one unit removed from service. To satisfy the criterion under 98th percentile dependable water conditions with one unit removed from service, the cancellation of planned outages in the Northwest zone and the use of emergency operating procedures would be expected to be required.
- Results from the transmission adequacy assessment show that with one Thunder Bay unit removed from service, the load supply criteria are met. With both Thunder Bay units removed from service the load supply criteria for the overall Northwest zone are not satisfied, but load supply for the local Lakehead area is expected to be adequate.

In conclusion, one Thunder Bay unit is required to supply the 2013 Northwest zonal demand within criterion and to allow for lower than normal water conditions. Beyond this period, a new assessment would be required to evaluate the need for one Thunder Bay unit after the conversion of Atikokan to biomass is completed, and the operating characteristics of the converted unit are well known.

– End of Section –

Table of Contents

Executive Summary ii

Table of Contents iv

List of Figures vi

List of Tables vi

1. Summary 1
- 1.1 Purpose 1
- 1.2 Major Assumptions 1
- 1.3 Major Findings 1
  - 1.3.1 Resource Adequacy 2
  - 1.3.2 Transmission Adequacy 2
- 1.4 Recommendations 2

2. Purpose 3
- 2.1 Reason for the Assessment 3
- 2.2 Specific Question(s) Addressed 3
- 2.3 Standards and Criteria 3

3. Resource Adequacy 4
- 3.1 Assumptions 4
  - 3.1.1 Low Water Hydroelectric Assumption 5
  - 3.1.2 Modeling East-West Tie De-ratings 6
  - 3.1.3 Northwest Zone Demand Forecast Considerations 6
- 3.2 Assessment Procedure 7
  - 3.2.1 Assessment Process 7
  - 3.2.2 Assessment Results 8
  - 3.2.3 Assessment Conclusion 8

4. Transmission Adequacy 10
- 4.1 Assessment Criteria 10
- 4.2 Northwest Zone Overview 10
- 4.3 Study Assumptions 10
  - 4.3.1 Power flows and equipment ratings 11
  - 4.3.2 Demand and Hydroelectric Forecast 11
- 4.4 Assessment Procedure and Results 12
  - 4.4.1 Northwest Zone 12
  - 4.4.1 Lakehead Area and A1B/T1M 13
- 4.5 Conclusions and Recommendations 14

Appendix A: Multi-Area Reliability Simulation (MARS) Program A–1

Appendix B: Transmission Assessment Criteria B–1

Appendix C: Northwest Transmission Zone Definitions C–1

Appendix D: Northwest Zone Overview D–1

Appendix E: Lakehead Area Analysis Results E–1

References.. a

List of Figures

Figure 1: Northwest zone Hydroelectric - Median, 90th, & 98th percentile Monthly Capacity. 5
Figure 2: Northwest zone Hydroelectric - Median, 90th, and 98th percentile Annual Energy . 6
Figure 3: Northwestern System and Interconnection Ties Transmission Overview........... C–1
Figure 4: East-West Transfer West flow D–1
Figure 5: Northwest zone inflow D–2
Figure 6: Northwest zone hydroelectric generation combined output D–2
Figure 7: Northwest zone demand D–2
Figure 8: E-W-TR-W limit D–3
Figure 9: Demand in the Lakehead area D–4
Figure 10: Thunder Bay G2 Active Power output D–4
Figure 11: Thunder Bay G3 Active Power output D–5
Figure 12: Thunder Bay temperature during the month of October.................................. D–6

List of Tables

Table 1: Existing Northwest zone Installed Generation Capacity.. 4
Table 2: Northwest Zone Demand - Historical and Forecast Annual Energy and Seasonal Peaks 7
Table 3: Loss of Load Expectation (LOLE) Results 8
Table 4: Monthly Peak Demand and Hydroelectric Forecast for 2013 11
Table 5: Northwest Zone Assessment Conditions 12
Table 6: Lakehead Area and A1B/T1M Assessment Conditions 13
Table 7: Ontario Annual Energy and Peak Demand including impacts of Embedded Generation and Conservation A–3
Table 8: Ontario Emergency Operating Procedures and their Aggregate Impact A–4
Table 9: Static Load Models for Simulations B–1
Table 10: Unit utilization in hours D–5
Table 11: Line loadings - Lakehead T7 out of service pre-contingency E–1
Table 12: Voltage Change - Lakehead T7 out of service pre-contingency.........................E–2
Table 13: Line loadings – All elements in service pre-contingency E–2
Table 14: Voltage Change – All elements in service pre-contingency E–3

1. Summary

1.1 Purpose

OPG filed a notice of request with the IESO on November 15th, 2012, seeking to de-register the Thunder Bay generation facility. This technical assessment was conducted by the IESO to determine whether the removal from service of the facility will or is likely to have an unacceptable impact on the reliability of the IESO-controlled grid during 2013. The facility, comprised of two units, is located in Ontario's Northwest zone and represents a total of 306 MW net installed capacity.

1.2 Major Assumptions

Provincial resource adequacy, with particular focus on the Northwest zone, was evaluated probabilistically in accordance with the criterion established in IESO's Ontario Resource and Transmission Assessment Criteria (ORTAC) (IMO_REQ_0041). Assumptions for future resources in the Northwest zone were based on the current Government directive for conversion of the Atikokan facility to biomass, and the most recent resource plans provided by the Ontario Power Authority (OPA). Additional forecast assumptions specific to the Northwest zone were applied to reflect the unique combination of resource, transmission and operating characteristics specific to the area of study. These included:

- Median and low water hydroelectric scenarios (50th, 90th and 98th percent dependability);
- Transmission ratings and de-ratings to the East West Transfer West (EWTRW) interface;
- Northwest zone demand forecast considerations.

The transmission system adequacy was evaluated in accordance with the ORTAC and the current operational documentation. The transmission adequacy studies were performed under the following conditions:

- Normal operating configuration and with one or two critical elements out of service;
- Demand levels up to the extreme weather, median-economic forecast;
- Low hydroelectric generation reflecting 98th percent dependable water conditions with all elements in service;
- Low hydroelectric generation reflecting 85th percent dependable water conditions with any single element out of service;
- Equipment ratings at ambient temperatures of 30 degrees Celsius windless conditions to represent summer conditions.

1.3 Major Findings

The technical assessment examining the removal of the Thunder Bay units from service concluded that, for the 2013 forecast year, while Atikokan is out of service for conversion to biomass:

- removing one Thunder Bay unit from service is not likely to have an unacceptable impact on the reliability of the IESO controlled grid, and;
- removing a second Thunder Bay unit from service is likely to have an unacceptable impact on the reliability of the IESO controlled grid.

1.3.1 Resource Adequacy

Results from the resource adequacy assessment demonstrate that one of the two units at Thunder Bay is required to maintain resource reliability in the 2013 forecast year. This conclusion is based primarily on the results of adequacy assessments conducted at 90^{th} and 98^{th} percentile dependable water conditions.

Under 90^{th} percentile conditions and one unit in service, the adequacy criterion is satisfied with planned outages and without dependence on the use of emergency operating procedures. Under 98^{th} percentile dependable water conditions and one unit in service, the cancellation of planned outages in the Northwest zone and the use of emergency operating procedures are required to satisfy resource adequacy criterion. Under the 98^{th} percentile dependable water conditions (a 1-in-50 year probability), due to the significantly lower probability of occurrence than 90^{th} percentile conditions, the IESO judges the mitigating actions (planned outage cancellations and emergency operating procedures) to be acceptable in order to satisfy the resource adequacy criterion.

Under median water conditions, resource adequacy criterion can be met with both Thunder Bay units removed from service.

1.3.2 Transmission Adequacy

Under the current forecast, one Thunder Bay unit can be removed from service without having an unacceptable impact on the reliability of Northwest supply. Removing both Thunder Bay units from service is likely to leave the Northwest zone with inadequate supply, unless additional capacity support is made available in the area. The conversion of Atikokan to biomass makes the unit unavailable for the duration of the study period.

When one autotransformer at Lakehead TS is out of service, reliance on the Lakehead area load rejection may be needed to prevent voltage collapse and equipment overloading in the Thunder Bay area, should the second autotransformer at Lakehead suffer an outage.

1.4 Recommendations

Following such conclusions, the Market Rules dictate that the IESO enter into negotiations with the registered market participant for a reliability must-run contract. Based on the technical assessment, those negotiations would contemplate a contract with OPG for one Thunder Bay unit, to secure the continued availability of the facility for a period of up to one year.

The Northwest zone will need to rely on one Thunder Bay unit to supply the zonal demand for 2013 to allow for lower than normal water conditions. Beyond this period, a new assessment would be required to evaluate the need for one Thunder Bay unit after the conversion of Atikokan to biomass is completed, and the operating characteristics of the converted unit are well known.

– End of Section –

2. Purpose

2.1 Reason for the Assessment

OPG filed a notice of request with the IESO on November 15th 2012, seeking to de-register the Thunder Bay generation facility located in Ontario's Northwest zone, representing a total of 306 MW net installed capacity to be removed from service.

2.2 Specific Question(s) Addressed

This assessment was performed to identify the potential impact of removing the Thunder Bay coal fired generation facilities from service on the reliability of the IESO controlled grid, in particular on the Northwest zone and Lakehead area.

2.3 Standards and Criteria

Provincial resource adequacy was evaluated in accordance with the Resource Adequacy Assessment Criterion contained in IESO's Ontario Resource and Transmission Assessment Criteria (IMO_REQ_0041) document. The criterion states:

"[Ontario's ("Each Area's")] probability (or risk) of disconnecting any firm load due to resource deficiencies shall be, on average, not more than once in ten years. Compliance with this criterion shall be evaluated probabilistically, such that the loss of load expectation [LOLE] of disconnecting firm load due to resource deficiencies shall be, on average, no more than 0.1 day per year. This evaluation shall make due allowance for demand uncertainty, scheduled outages and de-ratings, forced outages and de-ratings, assistance over interconnections with neighboring Areas and Regions, transmission transfer capabilities, and capacity and/or load relief from available operating procedures."

In applying this criterion, it is recognized that if a subset of the province, for example the Northwest zone, is not satisfying the LOLE, then the provincial LOLE criterion will not be satisfied.

The transmission adequacy for Ontario's Northwest zone was evaluated in accordance with:

- Market Rules Chapter 4 Grid Connection Requirements and Appendices;
- Market Rules Chapter 7 System Operations and Physical Markets;
- Ontario Resource and Transmission Assessment Criteria;
- Current operational documentation: Northwestern System Operating Limits and 115 kV Bus Voltage Limits and Operating Ranges.

– End of Section –

3. Resource Adequacy

3.1 Assumptions

General Electric's Multi-Area Reliability Simulation (MARS) program is used by the IESO to calculate the standard reliability index of loss of load expectation (LOLE) expressed in days per year. The MARS model is comprised of detailed load and generation information, a simplified transmission representation for Ontario's 10 transmission zones, and an option to model interconnection support from the five external areas to which Ontario connects. A description of the model including underlying Ontario demand, supply and transmission inputs used in this assessment is given in Appendix A: .

Within the broader context of meeting the provincial resource adequacy criterion of 0.1 day per year LOLE, this assessment focused on a specific set of assumptions for the Northwest zone. These assumptions reflect the unique combination of resource, transmission and operating characteristics attributed to the Northwest zone, including:

- Median and Low water hydroelectric scenarios (50^{th}, 90^{th} and 98^{th} percentile values)
- Transmission ratings and de-ratings to the East-West tie circuit
- Northwest transmission zone demand forecast considerations

Table 1 lists the existing installed generation capacity in the Northwest zone. Hydroelectric capacity accounts for the majority of existing Northwest zone resources with the balance coming from thermal resources, primarily the coal facility at Thunder Bay.

Table 1: Existing Northwest zone Installed Generation Capacity

Name/Group	Fuel Type	Output (MW)	% Total
Thunder Bay G2	Coal	153	10.8%
Thunder Bay G3	Coal	153	10.8%
TCPL Nipigon G1	Gas	24	1.7%
TCPL Nipigon G2	Gas	19	1.3%
West Coast Fort Frances G2	Biomass	47	3.3%
Hydroelectric	Water	793	55.9%
Greenwich Wind Farm	Wind	99	7.0%
Dispatchable Load	Load	75	5.3%
Demand Response	Load	56	3.9%
Total		**1419**	100%

The Northwest zone is connected to the rest of Ontario by the East-West (E-W) tie, a series of 230kV double circuit lines with a nominal capacity of 350 MW. Section 3.1.2 further describes the specific modeling assumptions considered in this study regarding the E-W tie. The Northwest zone is also connected to external control areas in Manitoba and Minnesota. The Manitoba interconnection is capable of up to 330/342 MW of import capacity (summer/winter), and the Minnesota interconnection is capable of up to 90 MW of import capacity.

Over the 2013 forecast timeframe, future resource such as Bowater with an installed capacity of 40 MW is assumed to be added to the Northwest zone based on the most recent Ontario Power Authority (OPA) resource plans[1].

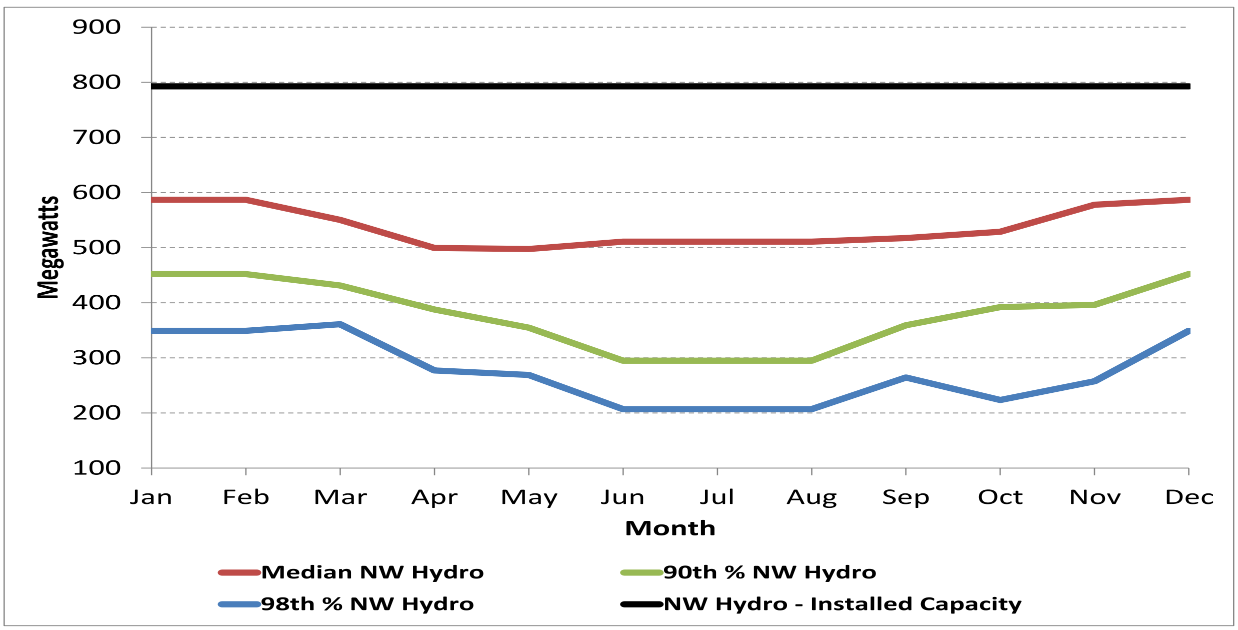
3.1.1 Low Water Hydroelectric Assumption

The IESO typically considers median water conditions when assessing resource adequacy over a one to two-year time horizon (mid-term). For this assessment, two additional low-water scenarios were developed exclusively for the Northwest zone. This was done in recognition of the relatively large proportion of hydroelectric generation in the zone (see Table 1), as well as the relatively limited transmission infrastructure connecting the Northwest zone to the rest of Ontario (see section 3.1.2). Median hydroelectric capacity and energy values were retained for the rest of the province.

Hydroelectric generation is subject to low-water (drought) conditions that can persist for long periods of time, resulting in significant reductions in the amount of capacity and energy supply that can be provided by hydro resources. Over the past 24 years, there have been several significant low water events in the Northwest zone that have impacted hydroelectric production over consecutive seasons.

Low water hydroelectric capacity values were constructed using 24 years of historical Northwest zone hydroelectric production data (1988-2011). Sample groups of Northwest zone hydroelectric production coincident to historical weekly peak demand periods[2] were drawn from the data for each winter and summer season, and each shoulder period month. From these monthly/seasonal samples, the 90th and 98th percentile values were selected. These two low water scenarios are plotted against the median water assumption for Northwest zone hydroelectric as depicted in Figure 1.

Figure 1: Northwest zone Hydroelectric - Median, 90th, & 98th percentile Monthly Capacity

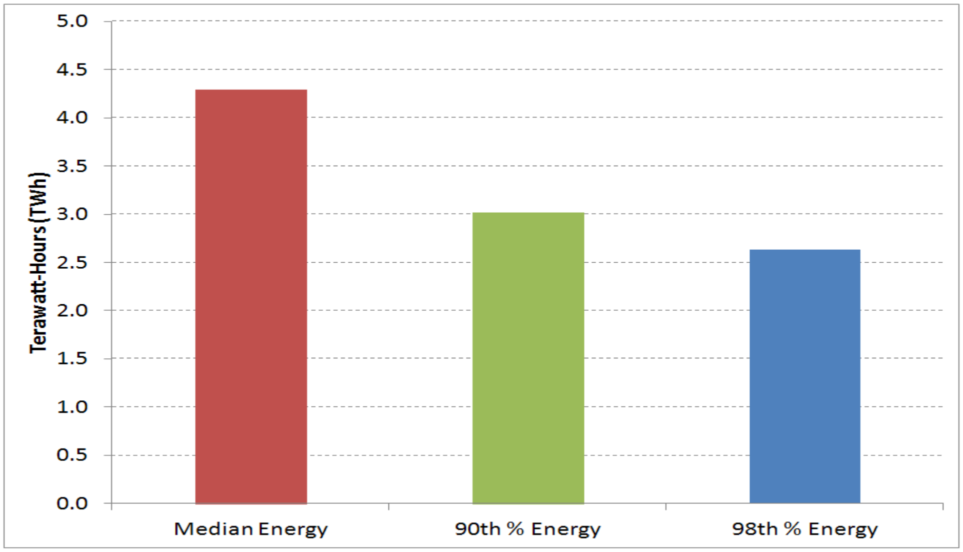


[1] OPA supply plan as of June 25, 2012. Future resources include all resources under the Committed and Directed categories.

[2] The 'weekly peak demand period' for each month is defined as the top 8 contiguous demand hours for each weekday that falls on the week in which the historical monthly peak occurred. For each historical year, each month is represented by a 'weekly peak demand period of 5 days x 8 hours = 40 hours. A contiguous 8-hour window for each weekday is considered appropriate for determining a sustainable hydro capacity contribution.

Ninetieth and ninety-eighth percentile annual energy values were also selected from the 24 years of historical data. The low water annual energy values are plotted against the median case in Figure 2.

Figure 2: Northwest zone Hydroelectric - Median, 90th, and 98th percentile Annual Energy



3.1.2 Modeling East-West Tie De-ratings

The Northwest zone is connected to the rest of Ontario by the East-West (E-W) tie, a series of 230kV double-circuit lines spanning Mackenzie TS, Lakehead TS, Marathon TS, Wawa TS and Mississagi TS. Geographically, this roughly spans the distance between Atikokan and Sault Ste. Marie.

During normal operations, the E-W tie has a Transfer-West (transfer into the NW zone, E-W-TR-W) capacity of 350 MW. During electrical storms, the risk of lightning strikes forces the E-W tie to be operated under high risk limits, which reduces E-W-TR-W to as low as 175 MW. Typically storm season is between May and September, but de-ratings of the E-W tie can occur throughout the year.

For this assessment, modeling of E-W tie de-ratings was applied probabilistically in the MARS program through the use of state transition rates with an Equivalent Forced Outage Rate (EFOR) of 11.7%. This value was derived from five years (2006-2010) of historical E-W tie transfer limit data.

3.1.3 Northwest Zone Demand Forecast Considerations

An hourly load forecast for each of Ontario's 10 transmission zones is used in the MARS model. The 2013 forecast is based on the most recent available demand, weather and economic data. It represents a normal weather, median economic forecast scenario decremented by embedded generation and conservation impacts[3]. Demand Response program has two components: Peak shifting, and Load reducing. Peak-shifting demand response program is embedded within the demand forecast, while the load reducing program is modeled as a resource. . More information on the overall Ontario demand forecast used in this assessment is provided in Appendix A: .

Northwest zone demand differs from the rest of the province in that the zone is a winter peaking area, due to higher winter heating load relative to summer cooling load. A large majority of Northwest zone load

[3] Data for embedded generation and conservation impacts provided by the OPA.

comes from industrial demand, notably the energy-intensive pulp and paper industry. Industrial demand in the Northwest zone has been declining over the past several years – especially in 2009, when the temporary shutdown of a large industrial load contributed to a 21% decline in Northwest zone energy demand over 2008. This large industrial load resumed operations in 2010 and overall industrial demand appears to have leveled off in 2011, contributing to a relatively flat but higher energy demand forecast for the Northwest zone. The following table shows historical and forecast energy demand and seasonal peaks for the Northwest zone.

Table 2: Northwest Zone Demand - Historical and Forecast Annual Energy and Seasonal Peaks

	Year	Summer Peak (MW)	Winter Peak (MW)	Energy (TWh)
Actual	**2007**	747	903	5.7
	2008	723	849	5.6
	2009	598	859	4.4
	2010	546	730	4.2
	2011	587	728	4.4
	2012	596	694	4.3
Forecast	**2013**	593	732	4.7

3.2 Assessment Procedure

3.2.1 Assessment Process

Resource adequacy was evaluated for two different coal scenarios for the assessment year 2013

1. *2TB Units Out*: both Thunder Bay units removed from service
2. *1 TBUnit Out:* one Thunder Bay unit removed from service

The two scenarios were evaluated under each of the three Northwest zone hydroelectric assumptions described in section 3.1.1: median, 90^{th} percentile and 98^{th} percentile dependable water conditions. All cases included the modeling of E-W tie de-ratings.

Equivalent Forced Outage Rates (EFORs) for both new and existing units are normally based on five-year history of actual forced outages. For Thunder Bay GS a rate of 8.5% was used.

Finally, three sets of operational measures were considered when testing the ability of each case to meet the provincial resource adequacy criterion of 0.1 day per year LOLE. These operational measures are described below:

a. Generation planned outages scheduled as-is
b. Northwest transmission zone generation planned outages cancelled
c. Northwest transmission zone generation planned outages cancelled and Emergency Operating Procedures activated

All cases were assessed for set *a.*, where planned outages based on market participant submitted information were scheduled in the MARS program. Additional operational measures *b.* and *c.* were considered for each case on an as-needed basis, to achieve the 0.1 day per year LOLE criterion. Each measure provides some degree of relief to the supply/demand balance, ultimately contributing to a lower LOLE. It should be noted that subsequent operational measures *b.* and *c.* are generally not considered in resource adequacy studies that use median hydroelectric assumptions. However, IESO planning assessments consider the implementation of one or more of these measures under lower than normal water conditions, as lower than normal water is considered to be a contingency situation[4]. Ultimately, measures *b.* and *c.* were not required for any of the median hydroelectric scenarios to meet the resource adequacy criterion, and were only employed under 90th and 98th percentile low water hydroelectric cases.

3.2.2 Assessment Results

The LOLE results of the resource adequacy assessment are presented below. The table contains the LOLE results for the three Northwest zone hydroelectric assumptions considered in the assessment (median, 90th percentile and 98th percentile). The results from the inclusion of the three sets of operational measures described in the previous section are also included. In the tables, scenarios that do not meet criterion (>0.1 day per year LOLE) are shaded red. For these scenarios, subsequent operational measures were used to reduce the LOLE in attempting to achieve criterion. Scenarios that have met the resource adequacy criterion (<0.1 day per year LOLE) are left un-shaded. Subsequent assessment of operational measures was not required for these scenarios, and these scenarios are represented by a dash ("-") in subsequent LOLE results tables.

3.2.3 Assessment Conclusion

The resource adequacy assessment results demonstrate that one of the two units at Thunder Bay is required to maintain resource reliability in the 2013 forecast year. This conclusion is based primarily on the results of adequacy assessments conducted at 90th and 98th percentile dependable water conditions.

Table 3: Loss of Load Expectation (LOLE) Results

Hydro Level	Planned Outages	Emergency Operating Procedures (EOP)	LOLE-without both Thunder Bay Units	LOLE-with 1 Thunder Bay Unit
Median	Yes	No	0.019	0.007
	Cancelled	No	-	-
	Cancelled	Yes	-	-
90th Percentile	Yes	No	0.113	0.037
	Cancelled	No	0.113	-
	Cancelled	Yes	0.045	-
98th Percentile	Yes	No	3.796	2.632
	Cancelled	No	3.75	0.256
	Cancelled	Yes	1.39	0.093

Under 90th percentile conditions and both Thunder Bay units out-of-service, the adequacy criterion is satisfied with cancellation of planned outages; and use of emergency operating procedures.

Under 98th percentile dependable water conditions and only one Thunder Bay unit in-service, the cancellation of planned outages in the Northwest zone, and the use of emergency operating procedures are required to satisfy the resource adequacy criterion.

The removal of two coal units at Thunder Bay results in LOLE levels that are not acceptable to the IESO. At 90th percentile dependable water, planned outage cancellations and emergency operating procedures are required to satisfy resource adequacy criterion with two units removed from service in 2013. At 98th

[4] The IESO recognizes that in the long term, repeated cancellation of planned outages can lead to reduced reliability of generation facilities and increased risk to forced outage. It is important to note that cancellation of planned outages was only required under low water conditions, which could last for up to one year. The IESO does not expect consecutive low water years requiring the cancelation of planned outages. As a result, the IESO interprets each year of study independent from the other years, rendering the cancelation of planned outages independent of planned outages cancellations that may be required for other years in the study.

percentile dependable water, LOLE values remain well above the 0.1 days per year criterion even with the cancellation of planned outages and use of emergency operating procedures. Given this, the IESO concludes that the removal from service of more than both coal units at Thunder Bay would result in unacceptable risk to resource reliability.

Under median water conditions, resource adequacy criterion can be met with both Thunder Bay units removed from service.

– End of Section –

4. Transmission Adequacy

The transmission adequacy assessment was performed to identify the impact of removing the Thunder Bay coal fired generation facilities from service. The studies focused on the reliability of the Northwest transmission system and, in particular, on the Lakehead area which includes the city of Thunder Bay and surrounding area.

4.1 Assessment Criteria

This technical assessment was performed to identify any potential violations of the transmission reliability criteria as defined in the ORTAC following the removal of the Thunder Bay generation facilities from service. The most relevant sections of the ORTAC used in the transmission assessment are summarized in Appendix B: .

4.2 Northwest Zone Overview

The Northwest zone is comprised of all high voltage facilities between Wawa and Kenora. It includes a set of two 230 kV overhead circuits with a cumulative length of over 800 km, connecting to six 230/115 kV transformation stations: Marathon TS, Lakehead TS, Mackenzie TS, Dryden TS, Fort Frances TS and Kenora TS. The underlying 115 kV system consists of a set of single circuits between the major stations normally operated in parallel with the major 230 kV lines and a number of radial circuits connecting loads and generators. A more detailed overview of the Northwest transmission zone including its currently defined limitations is provided in Appendix C:

The Northwest zone generation is predominantly hydroelectric with a total installed capacity of almost 800 MW. Sustained low water levels (drought) usually result in reduced hydroelectric output at peak that can be as low as 207 MW (Table 4). Historically, the Northwest zonal demand has reached levels higher than 1,000 MW but has rarely exceeded 700 MW since mid-2009. Under low water conditions, the peak demand is supported by the local thermal generators and energy imports into the Northwest zone. Unavailability of one of these resources increases the reliance on the others.

The Lakehead area is the largest load center in the Northwest zone, located around the city of Thunder Bay, and represents approximately 50% of the total Northwest zone demand at peak. It is made up of 115 kV transmission bounded by circuit A5A on the east, B6M on the west and the Lakehead TS 230/115 kV autotransformers, T7 and T8. The 230/115 kV Lakehead autotransformers provide the primary supply to this area.

In addition to coal and hydroelectric generation, the Northwest zone also contains two grid-connected thermal generation facilities fueled by biomass or natural gas, namely TCPL Nipigon and West Coast G2. Their output is partially dependent on their internal processes, sometimes increasing the flows variability in the zone. The West Coast G2 generator is connected behind the load facility meter, and the facility can either be a net injection or withdrawal. Due to the nature of the connection, its generation is accounted for through the net facility load forecast.

Finally, a new generator within the Bowater facilities is expected to be in service by the end of Q1 2013.

4.3 Study Assumptions

The following assumptions were developed based on the ORTAC, historical data, past planning practice and current operational documentation.

4.3.1 Power flows and equipment ratings

The power flows were estimated based on the following assumptions:

- To satisfy the provincial self-sufficiency clause, no support, both active and reactive, from Manitoba and/or Minnesota was assumed. The Northwest zone loads must be reliably supplied by local resources and flows through the E-W-TR-W interface.
- Consistent with Section 7.1 of the ORTAC, demand forecasts were based on extreme weather conditions and median economic growth.
- As water plays a very important role in the Northwest zone supply, with all elements in service pre-contingency, 98% of time dependable hydroelectric capacity was assumed.
- With a single element out of service pre-contingency, 85% of the time dependable hydroelectric capacity was assumed consistent with past planning practice.
- Wind farm output was assumed to be at approximately 20%, consistent with current operational planning assumptions.
- All load displacement and thermal generation was assumed to be in service at 100%, with the new Bowater generator dispatched to 40 MW.
- Equipment ratings were based on 30 º C temperature and windless conditions.

4.3.2 Demand and Hydroelectric Forecast

The following table contains the 2013 extreme weather monthly demand forecasts and the monthly 98% and 85% dependable hydroelectric capacity for the Northwest zone and the Lakehead Area.

Table 4: Monthly Peak Demand and Hydroelectric Forecast for 2013

Year 2013	98% dependable NW Hydroelectric (MW)	85% dependable NW Hydroelectric (MW)	98% dependable Lakehead Area Hydroelectric (MW)	85% dependable Lakehead Area Hydroelectric (MW)	Extreme Weather NW Peak Demand (MW)	Extreme Weather Lakehead Area and A1B/T1M Peak Demand (MW)
Jan	349	476	127	221	791	421
Feb	349	476	127	221	758	407
Mar	361	448	164	216	731	396
Apr	277	417	100	187	668	372
May	269	382	92	167	606	339
Jun	207	338	86	136	547	305
Jul	207	338	86	136	552	317
Aug	207	338	89	136	597	340
Sep	264	396	97	166	583	322
Oct	223	425	79	173	718	385
Nov	257	438	82	204	721	393
Dec	349	476	127	221	749	403

It can be observed in the table above that the difference between the forecasted extreme weather demand and hydroelectric output and, as a result, the external support required to reliably supply the demand is expected to be the largest during the month of October 2013. Therefore, all studied scenarios were prepared using the forecasted October 2013 levels.

4.4 Assessment Procedure and Results

4.4.1 Northwest Zone

The Northwest zone transmission assessment focused on the ability to supply the area demand using local resources and inflow over the E-W-TR-W interface.

Two peak load scenarios, one with all elements in service pre-contingency and one with a single Wawa-by-Marathon (WxM) 230 kV circuit out of service pre-contingency, were prepared to evaluate the transmission adequacy of the Northwest zone. The WxM outage was chosen as the single element out of service for consideration as it results in the highest de-rating of the E-W-TR-W interface. The initial conditions for both scenarios are listed in Table 5.

In order to prepare basecases consistent with the conditions described in Table 5, the station based peak load forecast provided by Hydro One was scaled proportionally and the power factor was maintained for the majority of the small load stations. Major industrial loads were individually scheduled based on their historical output and intended mode of operation. Hydroelectric units in the Northwest zone were dispatched proportional to their plant rating while keeping in service the minimum number of units to meet each plant's target. This way each unit was scheduled to operate close to its efficiency output.

Table 5: Northwest Zone Assessment Conditions

Interface	**Peak demand scenario October 2013 median growth extreme weather - All elements in service 98% dependable hydroelectric (MW)**	**Peak demand scenario October 2013 median growth extreme weather - Outage to 1 WxM circuit 85% dependable hydroelectric (MW)**
OMTE – Ontario Manitoba Transfer East	0	0
MPFN – Minnesota Power Flow North	0	0
Hydroelectric generation	223	425
Wind Generation	19	19
TCPL Nipigon	40	40
Thunder Bay G2	0	0
Thunder Bay G3	0	0
Bowater	40	40
Total NW Generation	322	524
Total NW Demand	718	718
Resulting E-W-TR-W Flow	420	200
E-W-TR-W Limit	350	250
Amount Exceeding E-W-TR-W Limit	70	0

Using the existing transfer limits, the E-W-TR-W interface has a maximum rating of 350 MW under fair weather conditions, reduced to maximum 250 MW for lightning storms in the Marathon to Lakehead area. Assuming no de-ratings of the E-W-TR-W interface with all elements in service, extreme weather demand, and 98% dependable water conditions, one Thunder Bay unit is required in service to control the E-W-TR-W flows to within 350 MW. This is consistent with the earlier resource adequacy analysis found in Section 3.

In addition, during single element outages or storms, extreme weather demand and 85% dependable water conditions, support from Thunder Bay is not required to control the E-W-TR-W flows within 250 MW.

4.4.1 Lakehead Area and A1B/T1M

Power flow studies were performed to determine the impact of removing Thunder Bay units from service on the transmission system supplying the Lakehead area and the load connected to A1B/T1M. The load on A1B and T1M was explicitly included as part of the demand forecast as it affects the loading on circuit T1M, a main supply point for Lakehead area.

Peak demand scenarios, one with all elements in service pre-contingency and the remaining with single element outages, were prepared under the initial conditions presented in Table 6.

Table 6: Lakehead Area and A1B/T1M Assessment Conditions

Interface	**Peak demand scenario October 2013 median growth extreme weather - All elements in service 98% dependable hydroelectric (MW)**	**Peak demand scenario October 2013 median growth extreme weather - Single element outage 85% dependable hydroelectric (MW)**
Generation		
TCPL Nipigon	40	40
Bowater	40	40
Thunder Bay G2 and/or G3	0	0
Aguasabon G1 & G2	12	20
Pine Portage G1- G4	31	67
Kakabeka Falls G1- G4	0	8
Cameron Falls G1 - G7	27	59
Alexander Falls G1 - G5	21	40
Silver Falls G1	0	0
Total Lakehead generation	171	274
Demand		
LAL + A1B/T1M – Lakehead Area Load plus the load on 115 kV circuits A1B and T1M.	385	385

With all transmission elements in service, the study results show that equipment loading is expected to be within continuous ratings and voltages within applicable pre-contingency ranges.

The tests also show that with one transmission element out of service, equipment loading is expected to be within applicable long term emergency ratings and voltages within applicable ranges. They also confirmed the most critical element for supplying the Lakehead area load is a 230/115 kV Lakehead autotransformer (in particular T7 due to the wider range reactive control device – SVC – connected to its tertiary winding).

To test the adequacy of the Lakehead area transmission system with one element out of service pre-contingency, studies assumed the most critical element, Lakehead T7, is on outage. It is to be noted that an autotransformer can be out of service, planned or forced, for significant periods of time (several days, sometimes weeks) during which the system must be prepared to withstand the loss of a second element. Load curtailment or load rejection is an acceptable mitigating measure to reduce the flows to within applicable long term emergency ratings with two transmission elements out of service. Section 7.1 of the ORTAC restricts the amount of load rejection or load curtailment that can be used to reduce post contingency flows within applicable ratings to 150 MW, except to account for local generation outages. If the Thunder Bay units are deregistered, they are not considered to be on outage.

The study results demonstrate that with both Thunder Bay units out of service, rejecting 75 MW of load in the Lakehead area is sufficient to be able to sustain the loss of a Lakehead autotransformer, when the companion autotransformer is on an outage. The 75 MW load rejection prevents overloading the 115 kV circuits from Marathon to Alexander (A5A, A1B and T1M) and unacceptable post-contingency voltage performance in the area.

4.5 Conclusions and Recommendations

The analysis indicates that:

- Removing one Thunder Bay unit from service is not likely to have unacceptable impact on the IESO controlled grid.
- Removing both Thunder Bay units from service is likely to have unacceptable impact on the IESO control grid and result in criteria violations. The absence of the Thunder Bay units would limit the supply capability of the Northwest zone and increase the risk of not supplying the current demand forecast, under low water conditions.
- Removing both Thunder Bay units from service is not likely to have an unacceptable impact on load supply to the Lakehead area.

– End of Section –

Appendix A: Multi-Area Reliability Simulation (MARS) Program

A.1 MARS Model – General Description

General Electric's Multi-Area Reliability Simulation (MARS) program[5] allows assessment of the reliability of a generation system comprised of any number of interconnected pools which in turn may consist of a number of interconnected areas. For this assessment, only the Ontario pool was modeled consisting of its 10 interconnected transmission zones.

A.1.1 Modeling Technique

A sequential Monte Carlo simulation forms the basis for MARS. The Monte Carlo method allows for many different types of generation and demand management options.

In the sequential Monte Carlo simulation, chronological system histories are developed by combining randomly generated operating histories of the generating units with the inter-area transfer limits and the hourly chronological loads. Consequently, the system can be modeled in great detail with accurate recognition of random events, such as equipment failures, as well as deterministic rules and policies that govern system operation.

A.1.2 Reliability Indices

The following reliability indices are available on both an isolated (zero ties between areas) and interconnected (using the input tie ratings between areas) basis:

- Daily loss of load expectation (LOLE in days/year)
- Hourly LOLE (hours/year)
- Loss of energy expectation (LOEE in MWh/year)
- Frequency of outage (outages/year)
- Duration of outage (hours/outage)
- Need for initiating Operating Procedures (days/year or days/period)

The use of Monte Carlo simulation allows for the calculation of probability distributions, in addition to expected values, for all of the reliability indices. These values can be calculated both with and without load forecast uncertainty. For the purpose of meeting the NPCC criterion of 0.1 days/year LOLE, only the daily LOLE was calculated in conducting this assessment.

The MARS program probabilistically models uncertainty in forecast load and generator unit availability. The program calculates expected values of LOLE and can estimate each Area's expected exposure to their Emergency Operating Procedures.

A.1.3 Resource Allocation Among Areas

The first step in calculating the reliability indices is to compute the area margins on an isolated basis, for each hour. This is done by subtracting the load demand from the total available capacity in the area for each hour. If an area has a positive or zero margin, then it has sufficient capacity to meet its load. If the

[5] See: http://www.gepower.com/prod_serv/products/utility_software/en/ge_mars.htm

area margin is negative, the load exceeds the capacity available to serve it, and the area is in a loss-of-load situation.

If there are any areas that have a negative margin after the isolated area margins have been adjusted for curtailable contracts, the program will attempt to satisfy those deficiencies with capacity from areas that have positive margins. Two methods are available for determining how the reserves from areas with excess capacity are allocated among the areas that are deficient. In the first approach, the user specifies the order in which an area with excess resources provides assistance to areas that are deficient. The second method shares the available excess reserves among the deficient areas in proportion to the size of their shortfalls. The user can also specify that areas within a pool will have priority over outside areas. In this case, an area must assist all deficient areas within the same pool, regardless of the order of areas in the priority list, before assisting areas outside of the pool. Pool-sharing agreements can also be modeled in which pools provide assistance to other pools according to a specified order.

A.2 Generation Resources

This assessment considered all existing resources as of Q3 2011 and new resources that were committed as of January 2011, to come into service over the period 2012 to 2014.

A.2.1 Wind

The wind resources were modeled probabilistically as a Type 1 Energy-Limited Resource with a cumulative probability density function (CPDF). The CPDF was derived by taking the median wind capacity factor from historical wind output at selected peak hours. Both modeled (10 years of history) and actual (5 years of history) wind output data was used. A conservative approach of taking the lower of the two (modeled or actual) capacity values was applied. Seasonal CPDF for summer and winter months, and monthly CPDF for shoulder months were modeled in MARS to represent various wind contribution to the system. Thirteen percent of the installed wind capacity was assumed to be available at the time of summer peak, and thirty-one percent was assumed to be available at the time of winter peak.

A.2.2 Hydroelectric

Hydroelectric resources were modeled in MARS as capacity-limited and energy-limited resources. Minimum and maximum capacity values and monthly energy values were provided for each station. Not including the Northwest zone hydro capacity assumptions described in Section 3.1.1 of this report, maximum capacity values were based on median monthly contributions at the time of system weekday peaks plus a contribution to operating reserve. Minimum values and monthly energy values were based on Market Participant submitted data for existing stations. For new hydroelectric projects, the contribution factor was based on the average contribution factors of existing projects on the river system where the new project is to be sited. Contribution factors ranged from 73% to 77% of installed capacity.

A.2.3 Thermal Resources

Five resource types were modeled as thermal resources, viz. nuclear, coal, gas, oil and biomass. The capacity values for each unit were based on monthly maximum capacity ratings contained in Market Participant submissions. In addition, the shutdown of two Nanticoke units planned for the end of October 2011 was modeled. Equivalent Forced Outage Rates (EFORs) for both new and existing units were based on five-year history of actual forced outages. For units with insufficient historical data, EFORs supplied by Market Participants were used in the assessment.

A.2.4 Interconnection Support

Although the NPCC criterion for resource adequacy assessments allows for reliance on interconnection support, imports from Ontario's five interconnected neighbours were not considered in this assessment. This is consistent with the approach used in the development of other IESO reliability assessments (e.g. 18-Month Outlook and the Ontario Reliability Outlook), where imports are not generally relied upon to meet peak demand in the planning timeframe but rather left as an additional resource to be used in real-time operations, as required.

A.3 Planned Outages

Planned outages were in general based on outage submissions from Market Participants as of Q2 2011. Planned outages for 2012 were modeled as submitted by Market Participants within the limitations of the MARS software. In subsequent years, the timings of planned outages were adjusted, so long as it was reasonable, in situations where overlapping outages result in significant reductions in system reserve and consequent increases in system LOLE.

For those generating units with no specified outages over the planning period, the planned outages were based on forecast Planned Outage Factors (POFs) submitted by Market Participants and/or a generic outage plan derived from historic outage patterns of existing units. Planned outage impacts for hydro and wind were assumed to be already accommodated in the capacity assumptions used.

A.4 Transmission Limits (Interface and Zonal)

For 2012, all transmission limits among the Ontario zones were modeled consistent with the IESO's Q2 2011 18-Month Outlook with the exception of the Flow Away from Bruce Complex (FABC). From December 2012 an increase in the FABC limit is expected for Bruce A units 1 and 2 coming in service earlier in 2012, and a new FABC limit in 2012 for the completion of the 500 kV Bruce-Milton line.

A.5 Demand Forecast

In the MARS program, demand was modeled as an hourly profile for each day of each year of the assessment period. In the present assessment, the modeled demand takes into account the effects of target conservation programs and expected contribution from embedded generation. The methodology used to generate these forecasts is described in Reference 2 – *Methodology to Perform Long Term Assessments* (IESO_REP_0266). The assumptions are consistent with those applied in preparing the forecast for the 18-Month Outlook. An allowance for load forecast uncertainty was also modeled as described below.

Table 7: Ontario Annual Energy and Peak Demand including impacts of Embedded Generation and Conservation

Year	Demand Forecast	
	Energy (TWh)	Peak (MW)
2013	140.4	23,266

A.5.1 Load Forecast Uncertainty (LFU)

Load forecast uncertainty (LFU) arises due to variability in the weather conditions that drive future demand levels. LFU was modeled in MARS through the use of probability distributions. These distributions were derived from observed historical variation in weather conditions that are known to effect demand, viz. temperature, humidity, wind speed and cloud cover. For each of the four years of assessment, LFU distributions were developed for every month to account for demand uncertainty.

A.6 Emergency Operating Procedures

Emergency Operating Procedures are available to deal with potential shortfall in reserve in the operating time frame, as summarized below. These procedures include reductions in operating reserves, voltage reductions, public appeals and emergency load reduction. This approach is approved for operational planning as indicated in the Resource Adequacy Assessment Criterion. As part of this assessment, assistance from Emergency Operating Procedures was only required to meet resource adequacy criterion in the low-water Northwest zone hydroelectric scenarios.

Table 8: Ontario Emergency Operating Procedures and their Aggregate Impact

EOP Action	Load relief (% of Demand or MW Value)
Public Appeals	1.0%
Disregard 30-minute Operating Reserve	540 MW
Disregard 10-minute Operating Reserve	1080 MW
Generator Stretch Capability	230 MW
3% Voltage Reduction (VR)	1.5%
5% VR (incremental to 3% VR)	1.1%

– End of Section –

Appendix B: Transmission Assessment Criteria

The most relevant sections[6] of the ORTAC used in the transmission assessment are summarized below:

- Section 2.4 – Load Forecasts and Load Modelling:

  The load levels used in the study shall be based on the latest forecast consistent with the IESO's and the OPA's latest long-term forecast. Load forecast uncertainty should be taken into account by investigating the sensitivity of the need date of various items (e.g. higher and lower loads).

  For assessment purposes, the power factor is assumed to be 0.90 at the *defined meter point*[7]. Studies should be done with a load model representative of the actual load. For power flow planning studies assessing the voltage stability of the bulk system, loads should normally be modelled as constant megavolt-amperes (MVA). In assessing voltage change limits and transient performance, a voltage dependent load model should be used. If specific information is not available, the load model in Ontario should be as indicated in the following table:

Table 9: Static Load Models for Simulations

Active Power		Reactive Power	
Constant Current	Constant Impedance	Constant Current	Constant Impedance
(%)	(%)	(%)	(%)
50	50	0	100

- Section 2.5 – Power Transfer Capability:

  A power transfer capability analysis should be performed throughout the study period taking into account the effects of planned *facilities*, the growth in loads, and the effects (if any), of various system generation patterns. The transfer limits should be determined for one or both directions of flow (as necessary).

  With all transmission *facilities* in service, the power transfer capability is determined for the worst applicable contingency. Also, it will generally be necessary to determine the effects of seasonal variations (e.g., summer and winter line ratings) on the limits.

- Section 2.6 – Local Area Requirements:

  With all transmission *facilities* in service (normal conditions), the schedule for generation in the receiving area should be based on the historically typical conditions. That is, for pre-contingency conditions, nuclear and run of river hydro-electric generation should be assumed at a level that is available 98% of the time. For example, on-peak conditions should be assessed with peaking hydroelectric generation plants, fossil plants and wind farms running at maximum output. Where *reliability* depends on local generation, sensitivity studies should be done to assess the impact of *outages* of local generation.

- Section 2.7 – Contingency-Based Assessment

[6] Only significant paragraphs of the ORTAC sections were copied/summarized in this report, please refer to the original document for the complete text: http://www.ieso.ca/imoweb/pubs/marketAdmin/IMO_REQ_0041_TransmissionAssessmentCriteria.pdf. In the event of any inconsistency between this report and the ORTAC, the ORTAC shall prevail to the extent of the inconsistency.

[7] Italicized words preserved as per ORTAC.

The *IESO-controlled grid* must be planned with sufficient capability to withstand the loss of specified, representative and reasonably foreseeable contingencies at projected customer *demand* and anticipated transfer levels. Application of these contingencies should not result in any criteria violations, or the loss of a major portion of the system, or unintentional separation of a major portion of the system. The *IESO-controlled grid* shall be designed with sufficient capability to keep voltages, line and equipment loading within applicable limits for these contingencies.

- Section 2.8 – Study conditions:

  The system load and generation conditions under which the contingencies are assumed to occur are chosen on a deterministic basis to represent the reasonable worst case scenario.

- Section 4.2 – Pre-contingency voltage limits:

  Under pre-contingency conditions with all *facilities* in service, or with a critical element(s) out of service after permissible control actions and with loads modeled as constant MVA, the *IESO controlled grid* is to be capable of achieving acceptable system voltages. For northern Ontario, acceptable system voltages on nominal 115 kV buses are between 113 kV and 132 kV, on nominal 230 kV buses between 220 kV and 250 kV.

- Section 4.3 – Voltage change limits:

  With all planned *facilities* in service pre-contingency, system voltage changes in the period immediately following a contingency are to be limited, for nominal 115 kV buses to 10% before and after tap changer action and between 108 kV and 127 kV, for nominal 230 kV buses to 10% before and after tap changer action and between 207 kV and 250 kV.

  After the system is re-dispatched and generation and power flows are adjusted the system must return to within the maximum and minimum continuous voltages identified in section 4.2.

  Before tap-changer action (immediate post-contingency period) a constant MVA load model can be used. If the voltage change exceeds the limits identified above, a voltage dependent load model should be used (e.g. $P \alpha V_{1.5}$, and $Q \alpha V_2$). After tap-charger action a constant power load model should be assumed (e.g. the load will return to its pre-contingency level).

- Section 4.7.2 – Loading Criteria:

  All line and equipment loads shall be within their continuous ratings with all elements in service and within their long-term emergency ratings with any one element out of service. Immediately following contingencies, lines may be loaded up to their short-term emergency ratings where control actions such as re-dispatch, switching, etc. are available to reduce the loading to the long-term emergency ratings.

- Section 7.1 – Load Security Criteria:

  The *transmission system* must be planned to satisfy *demand* levels up to the extreme weather, median-economic forecast for an extended period with any one transmission element out of service. The *transmission system* must exhibit acceptable performance, as described below, following the design criteria contingencies defined in sections 2.7.1 and 2.7.2. For the purposes of this section, an element is comprised of a single zone of protection.

  With all transmission *facilities* in service, equipment loading must be within continuous ratings, voltages must be within normal ranges and transfers must be within applicable normal condition stability limits. This must be satisfied coincident with an outage to the largest local generation unit.

With any one element out of service, equipment loading must be within applicable long-term *emergency* ratings, voltages must be within applicable *emergency* ranges, and transfers must be within applicable normal condition stability limits. Planned load *curtailment* or load rejection, excluding voluntary *demand* management, is permissible only to account for local generation outages. Not more than 150MW of load may be interrupted by configuration and by planned load *curtailment* or load rejection, excluding voluntary *demand* management. The 150MW load interruption limit reflects past planning practices in Ontario.

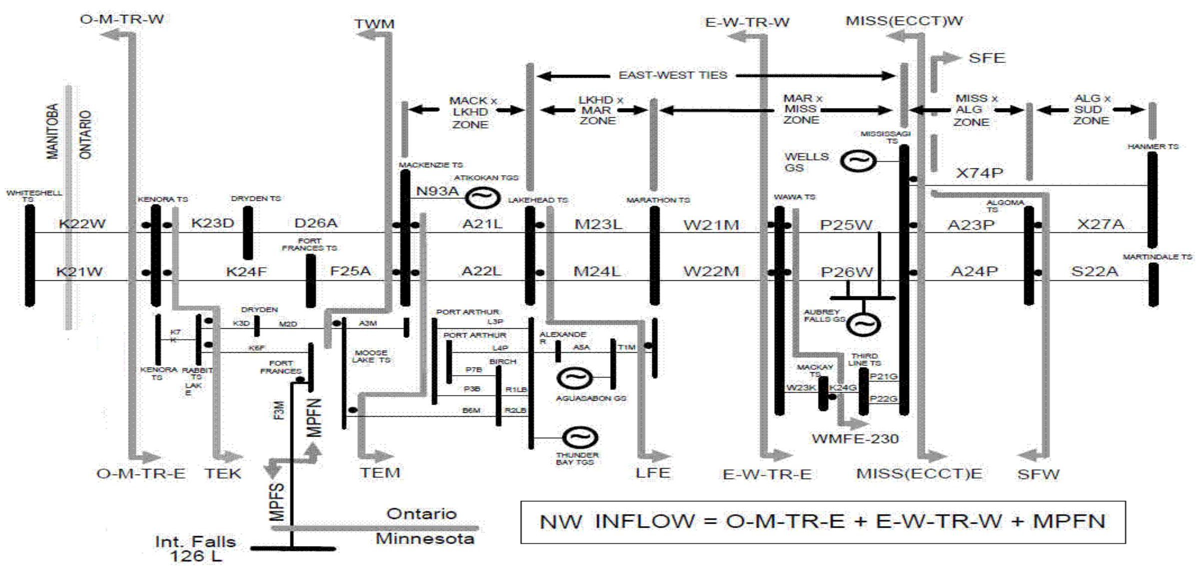
With any two elements out of service, voltages must be within applicable *emergency* ranges, equipment loading must be within applicable short-term *emergency* ratings and transfers must be within applicable *emergency* condition stability limits. Equipment loading must be reduced to the applicable long-term *emergency* ratings in the time afforded by the short-time ratings. Planned load *curtailment* or load rejection exceeding 150MW is permissible only to account for local generation outages. Not more than 600MW of load may be interrupted by configuration and by planned load *curtailment* or load rejection, excluding voluntary *demand* management. The 600MW load interruption limit reflects the established practice of incorporating up to three typical modern day distribution stations on a double-circuit line in Ontario.

– End of Section –

Appendix C: Northwest Transmission Zone Definitions

The Northwestern System Operating Limits define the Northwest zone transmission system as the part of the IESO Controlled Grid (ICG) bounded by Kenora TS in the west, Algoma TS in the east and Fort Frances TS at the Minnesota-Ontario Border. This includes the Ontario-Manitoba 230 kV Tie Circuits K21W and K22W, the Algoma TS to Sudbury 230 kV Circuits S22A and X27A and Mississagi TS to Hanmer TS 230 kV Circuit X74P and the Ontario-Minnesota 115 kV Tie Circuit F3M.

Figure 3: Northwestern System and Interconnection Ties Transmission Overview



The Northwest transmission zone is the subset of elements in the Northwestern system bounded by Kenora TS in the west, Marathon TS in the east and Fort Frances TS at the Minnesota-Ontario Border. This includes the Ontario-Manitoba 230 kV Tie Circuits K21W and K22W, the Marathon TS to Wawa TS 230 kV Circuits W21M and W22M and the Ontario-Minnesota 115 kV Tie Circuit F3M.

Northwest transmission zone inflow (NW INFLOW) is the sum of power flowing into the Northwest transmission zone, consisting of imports from Manitoba and Minnesota and the EWTRW as shown in the figure above.

The system interfaces part of the Northwest transmission zone identified on the above figure are as follows:

- Ontario-Manitoba Transfer East (O-M-TR-E) = MW flow east at Kenora TS on K21W and K22W
- Ontario-Manitoba Transfer West (O-M-TR-W) = MW flow west at Kenora TS on K21W and K22W
- Transfer East of Kenora TS (TEK) = MW flow east at Kenora TS on K23D and K24F plus MW flow east at Rabbit Lake TS on K3D and K6F.
- Minnesota Power Flow North (MPFN) = MW flow north at Fort Frances TS on F3M.

- Minnesota Power Flow South (MPFS) = MW flow south at Fort Frances TS on F3M.
- Transfer West of Mackenzie TS (TWM) = MW flow west at Mackenzie TS on D26A and F25A plus MW flow west at Moose Lake TS on M2D.
- Transfer East of Mackenzie TS (TEM) = MW flow east at Mackenzie TS on A21L and A22L plus MW flow east at Moose Lake TS on B6M.
- Lakehead Flow West (LFW) = MW flow west at Lakehead TS on M23L and M24L
- Lakehead Flow East (LFE) = MW flow east at Lakehead TS on M23L and M24L plus MW flow east at Marathon TS on T1M.
- East-West Transfer West (E-W-TR-W) = MW flow west at Wawa TS on W21M and W22M
- East-West Transfer East (E-W-TR-E) = MW flow east at Wawa TS on W21M and W22M

The Lakehead local area is defined as the 115 kV area bounded by Circuits A5A, B6M and the Lakehead TS 230/115 kV Autotransformers T7and T8. The following limits are defined for this local area:

- Lakehead Area Inflow (LAI) limit applies only under the following prior outage conditions:
  - Lakehead T7 or T8 o/s: LAI = The total megawatt flows (230 kV to 115 kV) on Lakehead T8 (or Lakehead T7) + A5A (@ Aguasabon) + B6M (@ Moose Lake TS)
  - Lakehead T7 (or T8) and B6M o/s (prior outage to T7 or T8 plus control action on B6M: LAI = The total megawatt flows (230 kV to 115 kV) on Lakehead T8 (or Lakehead T7) + A5A (@ Aguasabon)
- Lakehead Area Outflow (LAO) limit applies only under the following prior outage conditions:
  - Lakehead T7 or T8 o/s: LAO = The total megawatt flows (115 kV to 230 kV) on Lakehead T8 (or Lakehead T7) – A5A (@ Aguasabon) + B6M (@ Birch)
  - Lakehead T7 (or T8) and B6M o/s (prior outage to T7 or T8 plus control action on B6M: LAO = The total megawatt flows (115 kV to 230 kV) on Lakehead T8 (or Lakehead T7) - A5A (@ Aguasabon)
- Lakehead Area Load (LAL) is defines as the total megawatt inflow to the Lakehead 115 kV area (flow on the Lakehead TS autotransformers and A5A, and B6M) plus the megawatt generation within the area. During outages to a Lakehead TS autotransformer, the Lakehead Area Load is calculated by the formula:
  - LAL = MW transfer through the remaining Lakehead TS autotransformer + MW flow east at Moose Lake TS on B6M + MW flow west at Aguasabon GS on A5A + (Net MW output of generators at Thunder Bay TGS (including CTUs), Pine Portage GS, Kakabeka Falls GS, Cameron Falls GS, Silver Falls GS, Alexander GS and TCPL Nipigon GS)

– End of Section –

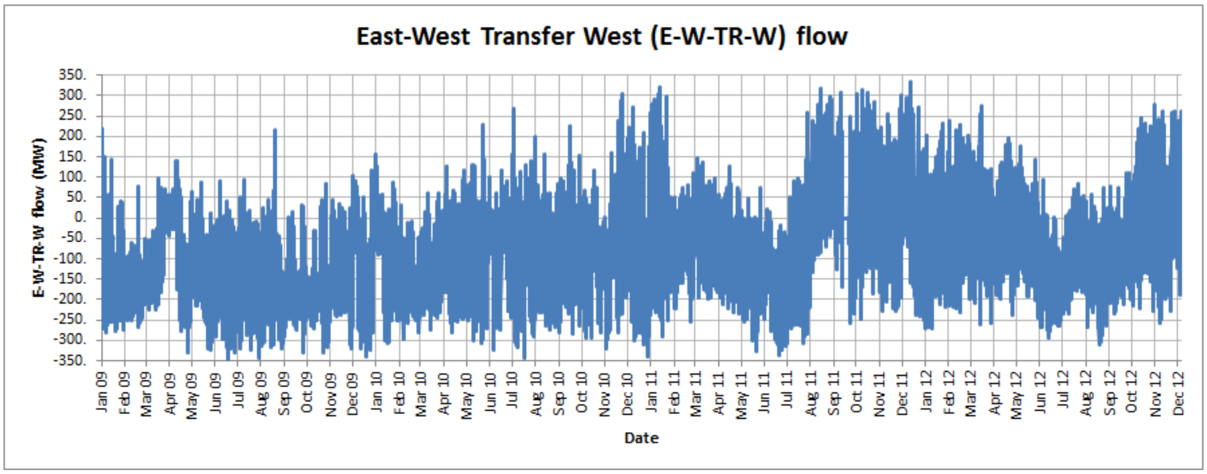
Appendix D: Northwest Zone Overview

Recent operational data is presented below to illustrate the specifics of the Northwest zone operation and ground assumptions used in this assessment.

D.1 East-West Transfer West Interface (E-W-TR-W)

The East-West Transfer West interface (E-W-TR-W) is defined as the flow east of Wawa on the 230 kV lines between Wawa and Marathon. The current operational documentation limits this flow to a maximum of 350 MW eastbound and 325 MW westbound. The following figure shows the E-W-TR-W flow readings since 2009:

Figure 4: East-West Transfer West[8] flow



The entire Northwest zone demand is supplied by local generation and flows into the zone from the rest of Ontario (over E-W-TR-W), from Manitoba (over O-M-TR-E) and from Minnesota (over MPFN). The sum of flows over these three interfaces, known as the Northwest transmission zone inflow, represents the total demand in the Northwest transmission zone that was not supplied by local generation. This inflow was significantly higher following the drought months of summer 2011:

[8] Negative indicates East-West Transfer East (E-W-TR-E) flow

Figure 5: Northwest zone inflow

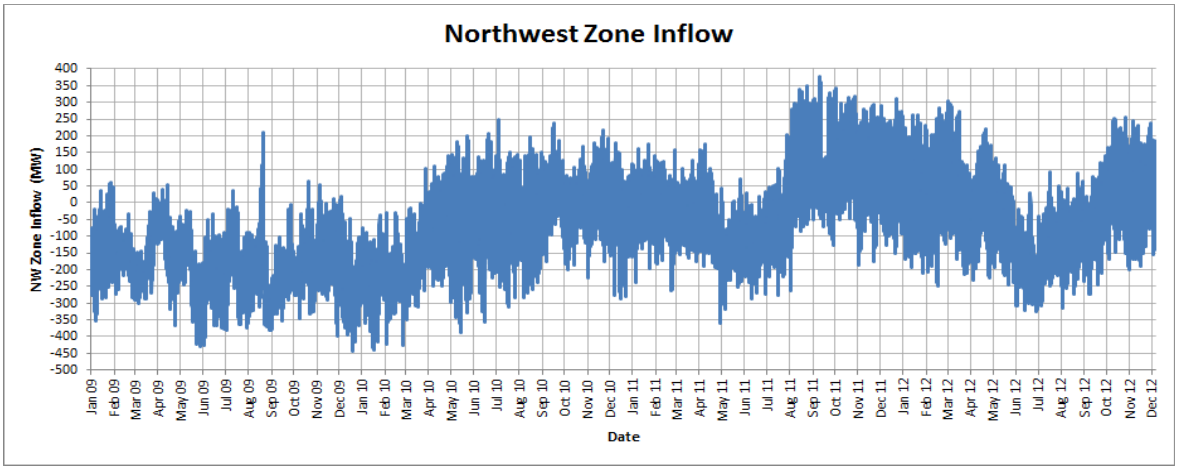


Figure 6: Northwest zone hydroelectric generation combined output

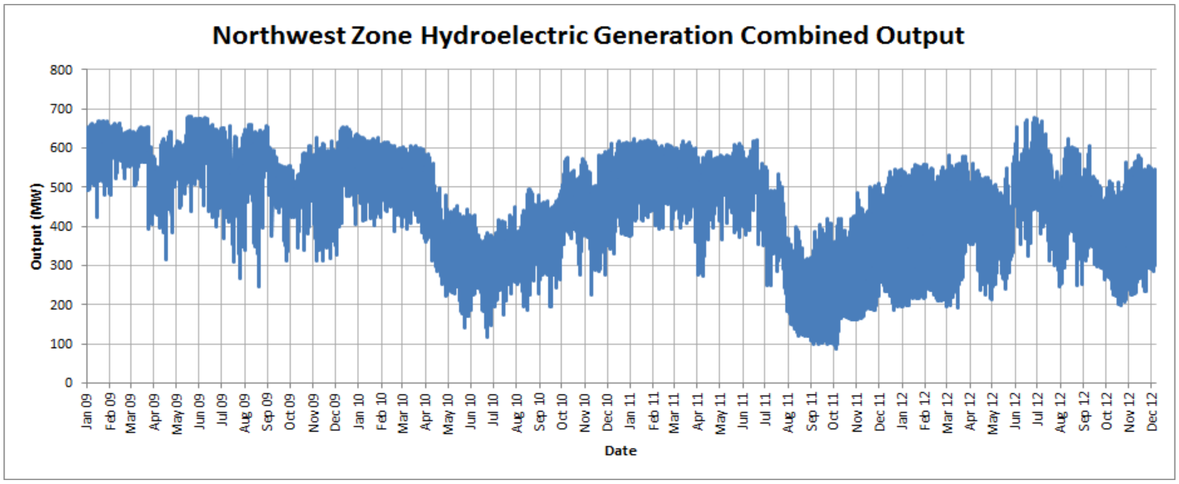
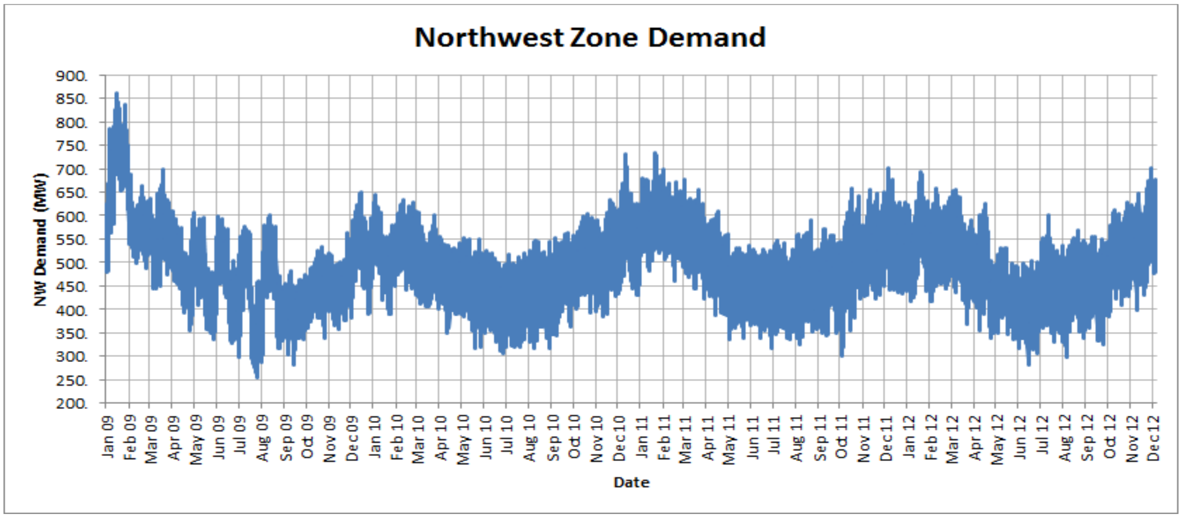


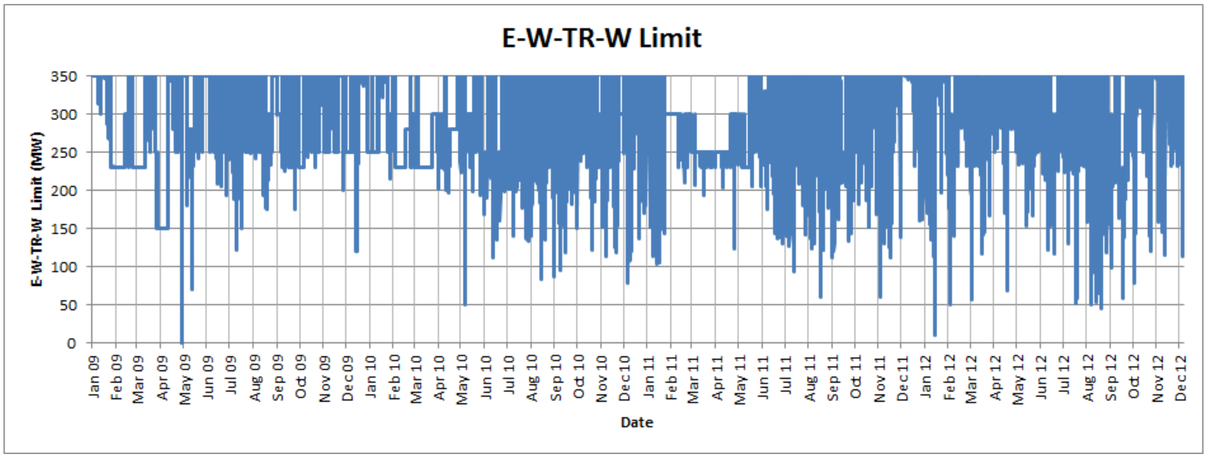
Figure 7: Northwest zone demand



The above Figure 5 and Figure 6 show the correlation between hydroelectric output and inflow into the Northwest zone; the zone's historical demand is illustrated in Figure 7. Low water conditions over the last two years significantly reduced the hydroelectric output in the zone and resulted in higher inflow. They also show the slow recovery of hydroelectric output following the relatively dry period of late spring 2010 and especially the months following the drought of July 2011.

The E-W-TR-W transfer limit depends on factors such as transmission outages, transfers through other Northwest interfaces and local weather conditions. De-ratings of the E-W-TR-W transfer limit ranged from a minimum of 50 MW to its maximum of 350 MW (250 MW under lighting storm conditions), sometimes for extended periods of time (an example would be March and April 2011):

Figure 8: E-W-TR-W limit



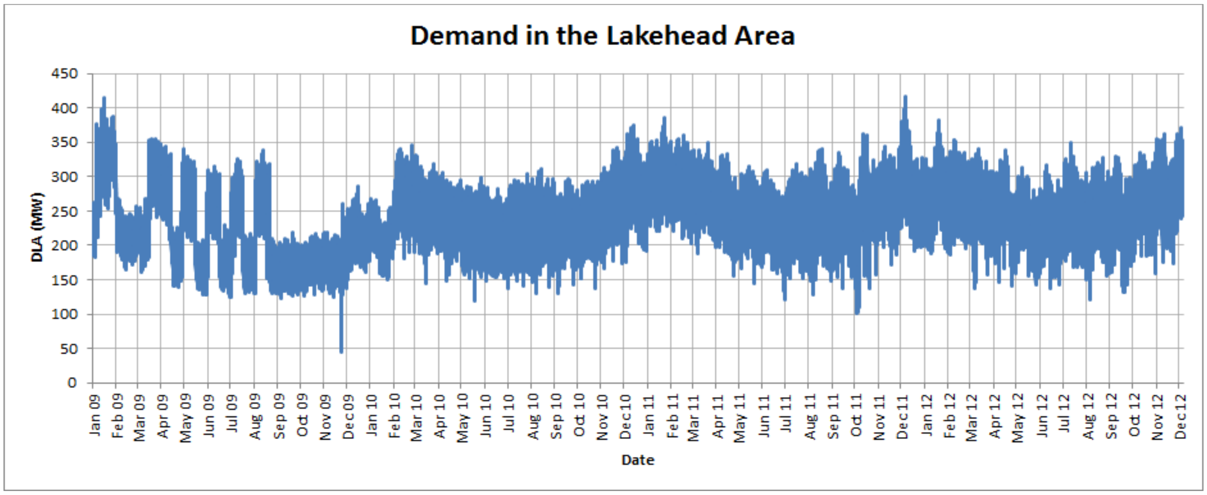
D.2 Lakehead Area and A1B/T1M Load

Lakehead Area Load (LAL) is defined as the sum of flows through one Lakehead 230/115 kV autotransformer when its companion is out of service, the 115 kV circuit A5A at Aguasabon GS and the 115 kV circuit B6M at Moose Lake TS plus the net output of the local generators at Thunder Bay, Pine Portage, Kakabeka Falls, Cameron Falls, Alexander, Silver Falls and TCPL Nipigon. It represents the demand that can be reliably supplied in and around the city of Thunder Bay with one 230/115 kV Lakehead autotransformer out of service. The load on A1B and T1M is primarily industrial and is important as it affects the loading on circuit T1M, a main supply point into the Lakehead area.

Most local hydroelectric generators are connected into Alexander TS, located close to the eastern end of the Lakehead area. Birch TS, located at the western end of the area, supplies most of the load. Thunder Bay GS, connected into Birch TS, currently provides generation right at the load center. Lakehead TS with its pair of 230/115 kV autotransformers connects this area to the 230 kV system and represents the main supply when the local generation is low or unavailable. The current operational documentation indicates that some of the 115 kV lines within the area may, under specific conditions, restrict the transfers and limit the capability of the Lakehead area transmission to supply the local demand.

The demand in the Lakehead area (DLA), shown below, represents the sum of flows through both Lakehead autotransformers, circuits A5A, B6M and the output of the local generation units.

Figure 9: Demand in the Lakehead area



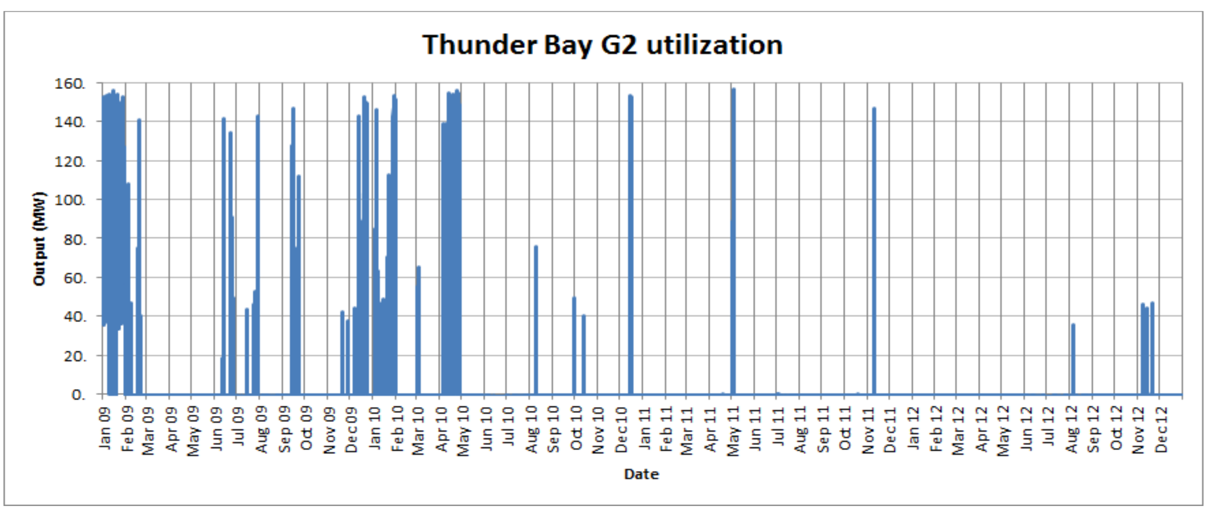
Demand in the Lakehead area has displayed a more consistent pattern since the beginning of 2010. Pre-recessionary levels were slightly higher and had larger fluctuations, possibly due to different participation levels of large industrial customers to load reduction/shifting programs. Current implementation of these programs resulted in a more consistent reduction in overall load levels, especially during peak periods.

The demand in Lakehead area is an important component of the total Northwest zone demand. Fluctuations of demand in the area impact the overall flows across the Northwest zone interfaces and its reliance on external sources to reliably supply the demand. Historically, the Lakehead area demand represented about 50% of the peak Northwest zone demand.

D.3 Thunder Bay Generation Utilization

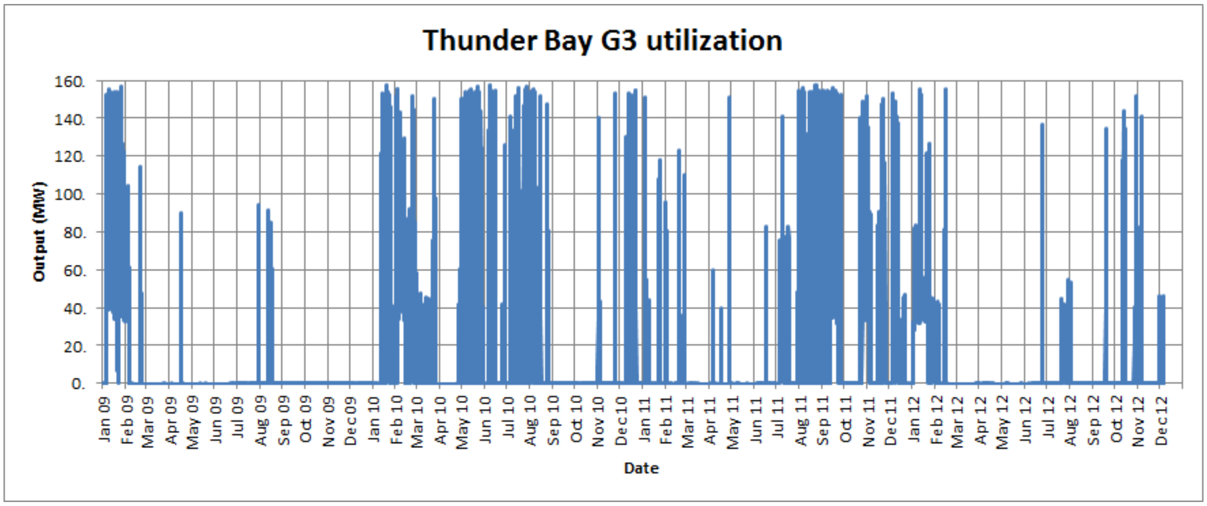
Following the government's directives, OPG has undertaken measures to comply with the CO_2 emission targets by reducing the output of the coal fired facilities. The utilization of Thunder Bay coal fired generators is shown in the following figures:

Figure 10: Thunder Bay G2 Active Power output



Thunder Bay G3 was used significantly more over the last two years, especially during and following the reduced water periods of spring 2010 and summer 2011:

Figure 11: Thunder Bay G3 Active Power output



The following table summarizes the Thunder Bay unit utilization since 2008[9].

Table 10: Unit utilization[10] in hours

Year	Thunder Bay G2 (hours)	Thunder Bay G3 (hours)
2008	4048 (46% of time)	3699 (42% of time)
2009	1244 (14% of time)	946 (11% of time)
2010	789 (9% of time)	2178 (25% of time)
2011	34 (0.4% of time)	1751 (20% of time)
2012	46 (0.5% of the time)	1168 (13% of time)

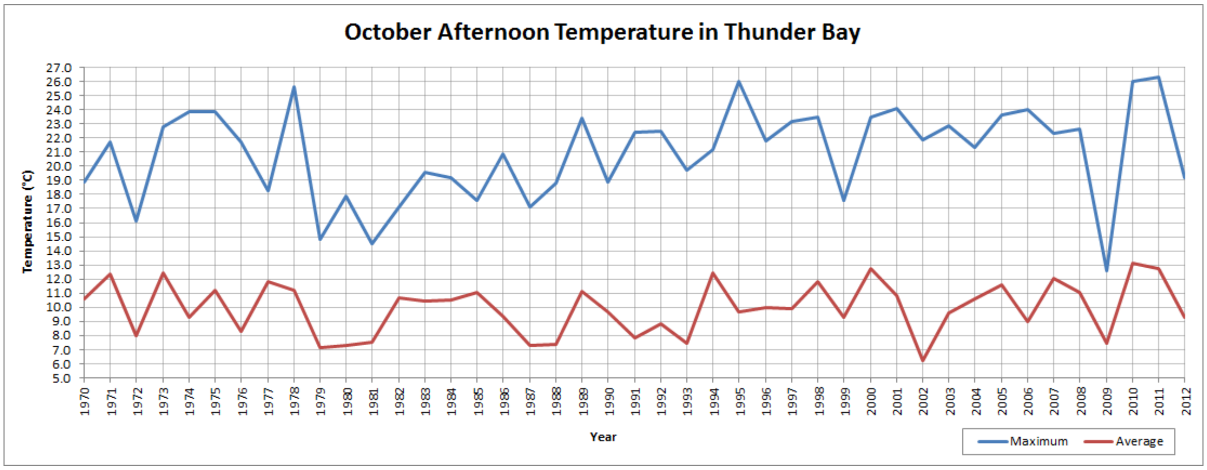
Due to the fact that over the last three years the demand presented a fairly consistent pattern and the water levels were low during 2010 and 2011, the table above provides some indication regarding the amount of support required from these units and its dependency on water levels.

D.4 Local temperature and impact on ratings

For planning purposes, summer ratings (at 30 degree Celsius) are used in the Northwest zone from May 1 to October 31 mainly to account for the fact that historical daily temperatures in October repeatedly exceeded 20 degree Celsius with peaks over 25 degree Celsius (Thunder Bay readings shown below as an example):

[9] The CO2 targets were significantly higher in 2008 so this year was included as an example of “unrestricted operation”.
[10] Utilization hours assumed the unit at or above minimum registered output (33 MW for Thunder Bay units 2 and 3).

Figure 12: Thunder Bay temperature during the month of October



– End of Section –

Appendix E: Lakehead Area Analysis Results

The following tables present the key Lakehead area analysis results. Although other outages were investigated, only results for the loss of Lakehead T8 with Lakehead T7 out of service pre-contingency are provided. The results demonstrate that after rejecting the load at Fort William under the aforementioned conditions, there were no line loading or voltage change violations.

Table 11: Line loadings - Lakehead T7 out of service pre-contingency

						Loss of Lakehead T8 - Reject Fort William	
CIRCUIT NAME	CONT RATING (A)	LTE RATING (A)	LTR RATING (A)	CIRCUIT LOADING PRE-CONTINGENCY (A)	% OF CONT	CIRCUIT LOADING POST-CONTINGENCY (A)	% OF LTE
A8L	430	430	430	240	55.81	254	59.07
A7L	340	340	340	217	63.82	230	67.65
A6P (ALxRE)	490	490	490	217	44.29	225	45.92
A6P (RExPA)	260	260	260	191	73.46	200	76.92
L3P	720	920	1130	397	55.14	285	30.98
L4P	620	790	960	271	43.71	163	20.63
R1LB (PNxLK)	330	330	330	169	51.21	175	53.03
R1LB (LKxBR)	620	790	870	298	48.06	190	24.05
R2LB (PNxLK)	420	420	420	192	45.71	200	47.62
R2LB (LKxBR)	620	790	890	285	45.97	182	23.04
B6M (BIxMU)	440	440	450	74	16.82	7	1.59
B6M (MUxST)	430	430	430	66	15.35	15	3.49
B6M (STxSH)	470	470	470	65	13.83	13	2.77
B6M (SHxIN)	470	470	470	57	12.13	22	4.68
B6M (INxKA)	460	460	460	57	12.39	23	5.00
B6M (KAxSA)	430	430	430	57	13.26	23	5.35
B6M (SAxCA)	620	740	770	60	9.68	36	4.86
B6M (CAxML)	620	740	770	60	9.68	36	4.86
A5A (ALxMN)	430	430	430	56	13.02	110	25.58
A5A (MNxSC)	430	430	430	71	16.51	118	27.44
A5A (SCxAG)	430	430	430	78	18.14	127	29.53
A1B (AGxNE)	570	570	570	73	12.81	68	11.93
A1B (NExTB)	620	790	960	157	25.32	217	27.47
T1M (TBxPC)	460	460	460	157	34.13	215	46.74
T1M (PCxMA)	620	790	960	189	30.48	248	31.39

Table 12: Voltage Change - Lakehead T7 out of service pre-contingency

BUS NAME	Minimum Continous Voltage (kV)	Maximum Continous Voltage (kV)	Pre-Contingency Voltage (kV)	Loss Lakehead T8 - Reject Fort William			
				PRE-ULTC Voltage (kV)	% Δ PRE-ULTC	POST-ULTC Voltage (kV)	% Δ POST-ULTC
Marathon 115 kV	120	126	123.4	127.1	3.00	125.2	1.46
Lakehead 115 kV	119	125.5	124.4	122.1	-1.85	122	-1.93
Alexander SS 115 kV	121	127	123.3	122	-1.05	121.9	-1.14
Port Arthur 115 kV	118	127	123.6	121.5	-1.70	121.4	-1.78
Fort William 115 kV Q4B	120	125	120.6	120	-0.50	120	-0.50
Fort William 115 kV Q5B	120	125	122	121	-0.82	120.9	-0.90

Table 13: Line loadings – All elements in service pre-contingency

CIRCUIT NAME	CONT RATING (A)	LTE RATING (A)	LTR RATING (A)	CIRCUIT LOADING PRE-CONTINGENCY (A)	% OF CONT	Loss of Lakehead T7	
						CIRCUIT LOADING POST-CONTINGENCY (A)	% OF LTE
A8L	430	430	430	146	33.95	151	35.12
A7L	340	340	340	133	39.12	137	40.29
A6P (ALxRE)	490	490	490	144	29.39	147	30.00
A6P (RExPA)	260	260	260	120	46.15	123	47.31
L3P	720	920	1130	402	55.83	397	43.15
L4P	620	790	960	305	49.19	301	38.10
R1LB (PNxLK)	330	330	330	98	29.70	101	30.61
R1LB (LKxBR)	620	790	870	301	48.55	297	37.59
R2LB (PNxLK)	420	420	420	111	26.43	114	27.14
R2LB (LKxBR)	620	790	890	288	46.45	284	35.95
B6M (BIxMU)	440	440	450	65	14.77	52	11.82
B6M (MUxST)	430	430	430	17	3.95	2	0.47
B6M (STxSH)	470	470	470	17	3.62	8	1.70
B6M (SHxIN)	470	470	470	8	1.70	7	1.49
B6M (INxKA)	460	460	460	14	3.04	17	3.70
B6M (KAxSA)	430	430	430	14	3.26	17	3.95
B6M (SAxCA)	620	740	770	31	5.00	36	4.86
B6M (CAxML)	620	740	770	31	5.00	36	4.86
A5A (ALxMN)	430	430	430	83	19.30	100	23.26
A5A (MNxSC)	430	430	430	97	22.56	114	26.51
A5A (SCxAG)	430	430	430	105	24.42	122	28.37
A1B (AGxNE)	570	570	570	95	16.67	105	18.42
A1B (NExTB)	620	790	960	219	35.32	236	29.87
T1M (TBxPC)	460	460	460	220	47.83	237	51.52
T1M (PCxMA)	620	790	960	251	40.48	268	33.92

Table 14: Voltage Change – All elements in service pre-contingency

BUS NAME	Minimum Continous Voltage (kV)	Maximum Continous Voltage (kV)	Pre-Contingency Voltage (kV)	Loss Lakehead T7			
				PRE-ULTC Voltage (kV)	% Δ PRE-ULTC	POST-ULTC Voltage (kV)	% Δ POST-ULTC
Marathon 115 kV	120	126	123.4	123.8	0.32	123.8	0.32
Lakehead 115 kV	119	125.5	123.8	124.3	0.40	124.3	0.40
Alexander SS 115 kV	121	127	123.7	124.1	0.32	124.1	0.32
Port Arthur 115 kV	118	127	122.9	123.5	0.49	123.5	0.49
Fort William 115 kV Q4B	120	125	120	120.3	0.25	120.3	0.25
Fort William 115 kV Q5B	120	125	121.3	121.8	0.41	121.8	0.41

References

Document Name	Document ID
Methodology to Perform Long Term Assessments	IESO_REP_0266
Ontario Resource and Transmission Assessment Criteria	IESO_REQ_0041

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