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May 25, 2011

BY COURIER, RESS AND EMAIL

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
2300 Yonge Street
27th Floor, Box 2329
Toronto, ON M4P 1E4

Dear Ms. Walli:

Re: Trout Creek Wind Power Inc.
Application for Amendment to Hydro One Networks Inc. Electricity Distribution License ED-2003-0043
Board File No: EB-2011-0209

We are counsel to the Trout Creek Wind Power Inc. (the "**Applicant**").

Please find enclosed two (2) copies of the Application and Pre-filed Evidence of the Applicant in the above mentioned proceeding. An electronic copy was filed on the Board's RESS system and two (2) hard copies are attached to this letter.

The Applicant requests the Board proceed with the interim relief requested in the Application immediately.

If there are any questions please feel free to contact the undersigned at your earliest convenience.

Yours truly,

AIRD & BERLIS LLP

Scott Stoll

Scott A. Stoll

SS/hm

Encl.

cc: A. Pye, OEB
T. Schneider, Trout Creek
M. Graham, Hydro One

9394779.1

EB-2011-0209

TROUT CREEK WIND POWER INC.: REQUEST FOR AN AMENDMENT TO HYDRO ONE NETWORKS INC. DISTRIBUTION LICENSE No. ED-2003-0043

MAY 25, 2011

Trout Creek Wind Power Inc.
Exemption Application

APPLICATION EXHIBIT LIST

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B			**Applicant's Pre-filed Evidence**
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		4	Generation License EG -2008-0130
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IN THE MATTER of the *Ontario Energy Board Act, 1998*, S.O. 1998, c.15, Schedule B;

AND IN THE MATTER a request for an order(s) pursuant to section 74(1)(b) amending the distribution license of Hydro One Networks Inc. to provide an exemption from compliance with sections 6.2.4.1(e) and 6.2.18(a) of the Distribution System Code in respect of the Trout Creek Power Inc. for the Trout Creek Wind Farm (Hydro One Connection No. 12,780);

APPLICATION

Introduction

1) Trout Creek Power Inc. ("**Trout Creek**" or "**Applicant**") is the developer of a 10MegaWatt wind power project known as the "Trout Creek Wind Farm" (the "**Project**") near North Bay Ontario. Trout Creek is a subsidiary of Schneider Power Inc., a developer of several wind power projects in Ontario

2) Schneider Power, a wholly owned subsidiary of Quantum Fuel Systems Technologies Worldwide Inc. (NASDAQ: QTWW), is one of North America's leading CleanTech companies and independent power producers ("IPP") focusing solely on renewable energy. It owns and operates a portfolio of renewable electricity generation facilities in North America, and holds a minority interest in a wind facility in Germany. It manages a portfolio of 30+ clean electricity generation development projects located on the most promising and prospective wind and solar power areas in the United States, Bahamas and the Dominican Republic.

3) Trout Creek and Schneider Power have their head offices in Toronto, Ontario.

4) The correspondence with Hydro One confirms that Trout Creek is to provide a Connection Cost Deposit of $3,402,574.64 prior to 4:00p.m. on May 26th, 2011 or the capacity allocated to the Project will be removed as provided for in the Distribution System Code ("**DSC**").

Interim Relief

5) The Applicant is requesting immediate relief prior to May 26, 2011 at 4:00pm in the form of an Order or Orders of the Board:

   i) prohibiting Hydro One Networks Inc. ("**Hydro One**") from taking any steps to remove the capacity allocated to the Trout Creek Wind Farm until the final conclusion of this Proceeding; and

   ii) A requirement that Trout Creek Power execute the Connection Cost Agreement with Hydro One, and pay a deposit of $200,000 to Hydro One prior to July 15, 2011 in respect of the Project.

6) The preservation of the current capacity allocation during this hearing is vital to ensuring the Applicant is not irreparably harmed through the loss of the capacity allocation.

Permanent Relief

7) The Applicant request that the Board find the suggested amendment is in the public interest and amend Schedule 3 of the distribution license of Hydro One to include the following exemption:

> *For the Trout Creek Wind Farm (Hydro One Project #12,780), Hydro One shall be exempted from the current connection cost deposit stipulated in s. 6.2.18(a) of the Distribution System Code (the "DSC) and shall, instead, adhere to the following schedule:*
>
> 1. *$20,000 per MW of capacity shall be paid by the proponent to Hydro One upon the execution of the Connection Cost Agreement .*
>
> 2. *An additional deposit in the amount of 30% of the total estimated cost, as estimated by Hydro One, less the amount received by Hydro One under paragraph 1 above, shall be paid by the proponent to Hydro One no later than 4 months after the proponent notifies Hydro One that it has completed the Renewable Energy Approval.*
>
> 3. *No later than 180 days after Hydro One receives payment of the amount referenced in paragraph 2 above, Hydro One shall provide to the proponent a*

construction schedule and a more accurate estimate of the project cost, if such estimate is requested and paid for by the proponent. The payment for the estimate shall be drawn from the deposit to the extent possible.

4. *The balance of the total estimated cost, as estimated by Hydro One based upon the best available information, shall be paid by the proponent to Hydro One no later than 30 days after the proponent notifies Hydro One that it is proceeding to construction.*

5. *Hydro One and the proponent shall mutually agree upon an in-service date that is no later than 2 years after Hydro One receives the balance referenced in paragraph 4, above, subject to the following: in cases where a transmission upgrade or new transmission facilities are required, Hydro One and the proponent may agree to an in-service date that is later than two years after Hydro One receives the balance referenced in paragraph 4, above.*

6. *The Expansion Deposit, as stipulated by Section 3.2.20 of the DSC shall be paid to Hydro One at the same time as the payment in paragraph 4.*

Notwithstanding the foregoing, if at any time the above-noted payments to Hydro One are insufficient to cover Hydro One's costs as estimated by Hydro One, the proponent shall pay, to Hydro One, additional funding sufficient to meet the shortfall identified by Hydro One, and Hydro One shall be relieved of its obligation to perform such further work until it receives the said additional funding.

8) Trout Creek believes this affirmation of existing rights pending the issuance of a decision is consistent with the statutory mandate of the Board and the Board's *Rules of Practice and Procedure*. Further, Trout Creek does not believe such a delay will adversely impact any other party.

The Distribution System Code

9) The DSC requires a distributor to allocate capacity to a generator and within 6 months of such allocation to execute a connection cost agreement with the generator and receive 100% of the connection cost estimate. The total deposit being required by Hydro One for is $3,402,574.64. .

10) The relevant sections of the DSC are reproduced below:

6.2.4.1 Subject to section 6.2.4.2, a distributor shall establish and maintain a capacity allocation process under which the distributor will process applications for the connection of embedded generation facilities. The capacity allocation process shall meet the following requirements:

e) an applicant shall have its capacity allocation removed if:

i. a connection cost agreement has not been signed in relation to the connection of the embedded generation facility within 6 months of the date on which the applicant received a capacity allocation for the proposed embedded generation facility;......

6.2.18 A distributor shall enter into a connection cost agreement with an applicant in relation to a small embedded generation facility, a mid-sized embedded generation facility or a large embedded generation facility. The connection cost agreement shall include the following:

a. a requirement that the applicant pay a connection cost deposit equal to 100% of the total estimated allocated cost of connection at the time the connection cost agreement is executed;

The OEB Act and Amending a License

11) Section 74(1)(b) of the OEB Act permits any person to apply for an amendment to a license. Where the Board finds the amendment is in the public interest, as set out in the *Electricity Act, 1998* S.O. 1998, c.15, Schedule A, (the "*Electricity Act*") the Board may grant such an amendment.

74.(1) The Board may, on the application of any person, amend a licence if it considers the amendment to be,

(a) necessary to implement a directive issued under this Act; or

(b) in the public interest, having regard to the objectives of the Board and the purposes of the *Electricity Act, 1998*.

12) Wind power is a vital component of the green energy policy, the *Green Energy and Green Economy Act*, and the policies of the Government of Ontario. The purpose of the *Electricity Act,* section 1(d), includes:

(d) to promote the use of cleaner energy sources and technologies, including alternative energy sources and renewable energy sources, in a manner consistent with the policies of the Government of Ontario;

13) Further, this exemption request is not only consistent with, but advances, the objectives of the Board, section 1(1) of the OEB Act, which includes:

> 1(1) 5. To promote the use and generation of electricity from renewable energy sources in a manner consistent with the policies of the Government of Ontario

14) The Project will result in significant local investment and approximately 16,400 hours of employment during construction. Schneider Power has a long-standing reputation of using local trades for its construction projects, whereas the balance of plant is anticipated to be built with a local materials and labour content in excess of 60%. The project will reduce transmission costs, increase grid stability and reliability for the end consumer as it is located between the two primary power generation hubs in southern and northern Ontario. The project has significant community support and involvement, including plans by the local chamber of commerce to use the facility as a tourist attraction – Trout Creek has been economically depressed ever since the Highway 11 bypass.

15) As such, completion of the project is in the public interest.

16) The Applicant is of the view that this proposal is consistent with the principles that neither the distributor nor other ratepayers should be at risk; that the generator pays its fair costs; and that the projects not unduly hold capacity allocations where the project is not progressing through to completion.

17) The Applicant has diligently pursued the Project but has been subjected to significant delays as a result of the Ministry of Natural Resources' site release procedure and therefore has been unable to complete the studies and permitting for the Project. The Ontario Power Authority has recognized 6 months of delay under the Force Majeure provisions of the FIT Contract. Further, the Ontario Power Authority has extended the Milestone Date for Commercial Operation for an additional 12 months as a result of other concerns with the development of renewable energy projects.

The Conduct of the Proceeding

18) This proceeding will be supported with written pre-filed evidence and such additional evidence as the Applicant may request and as may be acceptable to the Board. At this time, the Applicant prefers the proceeding take place writing in English.

19) The persons that may have an interest in this proceeding includes the Ontario Power Authority, the Independent Electricity System Operator and Hydro One. Trout Creek request the Board not require the placement of notice in the Globe and Mail or similar publication due the lack of impact on other persons and the anticipated cost of more than $25,000.

20) The Applicant requests that communication in respect of this proceeding be conducted in English and be copied to:

a) The Applicant: Trout Creek Power Inc.
Address: 49 Bathurst Street, Suite 101
Toronto, ON
M5V2P2

Attention: Mr. Thomas Schneider
Telephone: (416) 847-3724 ext. 235
Fax: (416) 847-3729
Email: t.s@schneiderpower.com

b) The Applicant's Counsel: Aird & Berlis LLP
Address: Suite 1800, box 754
Brookfield Place, 181 Bay Street
Toronto, ON M5J 2T6

Attention: Mr. Scott A. Stoll
Telephone: (416)865-4703
Fax: (416)863-1515
Email: sstoll@airdberlis.com

21) The Applicant request the Board make such order(s) as are necessary for the scheduling and proper consideration of this Application. The Applicant request the Board render a decision regarding the interim relief stay by May 26, 2011 and request a final decision at the Board's earliest opportunity.

DATED May 25, 2011 at Toronto, Ontario

TROUT CREEK POWER INC.
By its Counsel
AIRD & BERLIS LLP

Original signed by Scott Stoll

____
Scott A. Stoll

Pre-filed Evidence
of
Trout Creek Wind Power Inc.

Part I. Introduction

Trout Creek Wind Power Inc. ("**Trout Creek**" or the "**Applicant**"), a licensed generator, EG-2008-0130 (Exhibit B, Tab 1, Schedule 4, is requesting an amendment of Hydro One Networks Inc.'s ("**Hydro One**") distribution license ED-2003-0043, schedule 3, (a copy of which is provided at Exhibit B, Tab 1, Schedule 2) to provide an exemption from sections 6.2.4.1(e)(i) and 6.2.18(a) of the Distribution System Code ("**DSC**"). The timing requirements of the DSC combined with the lengthy and ever evolving limitations and requirements of the regulatory approvals process for projects on Crown land and the Ontario Power Authority's ("**OPA's**") Feed-In Tariff Program ("**FIT**") require Trout Creek to seek this exemption to align the timing requirements with the development process. The failure to provide the requested relief will result in the proposed project, the Trout Creek Wind Farm, being discontinued.

Trout Creek is not suggesting that proper costs of connection are not paid by the generator, but rather, that the front-end loading of such costs prior to be able to complete testing and permitting are potentially fatal to the projects. The Connection Cost Estimate Deposit ("**CCD**") is more than 10% of the overall capital investment in the Project.

The approach to the evidence will be to highlight the requirements and obligations as well as the actual events that have transpired. The evidence deals with this specific request, the principles behind the request, the statutory test for granting the amendment and the evidence supporting the fulfillment of the public interest by the granting of the amendment.

Part II. The Impact on the Project

a) Immediate Relief Required

The Applicant has sought immediate relief from the obligations of sections 6.2.4.1(e)(i) and 6.2.18(a) of the DSC as it will not be able to make the payments required in the stipulated timeframe. On May 12, 2011, Trout Creek received an email from Hydro One requiring the execution of the Connection Cost Agreement (the "**CCA**") and the payment of $3,402,574.64

prior to 4:00p.m. on May 26, 2011. Prepaying such an amount, over three years before COD is not consistent with the typical project development cycle and places significant financial burden on the developer – presuming the developer can even fund such substantial parts of the project.

If immediate relief is not provided, Trout Creek will lose their allocated capacity and eventually the FIT Contract. If that occurs, Trout Creek would suffer irreparable harm from the discontinuance of the project. Granting the relief on an interim basis will preserve Trout Creek's position until this proceeding is concluded without unduly impacting any third parties.

Trout Creek believe its request is consistent with the Board's Decision in EB-2011-0067 (Exhibit B, Tab 1, Schedule 5) which recognized that a diligent developer should not have the capacity allocation placed at risk through no fault of the developer.

b) The Development Timeline

On April 30, 2010, Trout Creek entered into a contractual agreement with the OPA to supply electricity on or before the Milestone Date for Commercial Operation ("**MDCO**") of April 30, 2013. An unforeseeable delay in obtaining Applicant of Record status, which was beyond the control of the Applicant, has prevented Trout Creek from commencing necessary studies in support of the application for permits necessary to proceed to the MDCO on schedule.

The delay in the issuance of Applicant of Record status has resulted in the Applicant not being able to submit a proposal for a wind testing facility and associated permit application in a timely manner. This delay has also resulted in the Applicant not being able to commence the REA process in a timely manner.

The delay is largely a result of the actions or inactions of the Ministry of Natural Resources ("MNR") and the Ministry of the Environment ("MOE"). The delay has compromised the schedule for Project development to the extent that the Applicant will not be able to meet the milestones and deadlines established in the FIT Contract all of which was beyond the control of the Applicant.

The MNR provided the Applicant with a "*Windpower Applicant Declaration Form*" on June 10, 2010 after which the Applicant subsequently submitted the completed form to the MNR six days later. Through discussion with the MNR it was agreed that the public notification commencement date would be left blank because the MNR had instructed that the Applicant not issue public notice of the proposal until such time that they had satisfactorily notified and consulted with potentially interested or affected Aboriginal communities.

MNR began to compile a list of Aboriginal communities requiring notification of the proposal prior to the June 7th meeting. The final list, collaboratively developed by the MNR and the MOE, was not finalized until October 6, 2010. Throughout that period, the Applicant elicited regular updates on progress being made toward finalizing the list and continued to work on other aspects of the wind testing proposal and the wind farm proposal.

As a result of these delays and the impact on the Project, on August 19, 2010, Trout Creek requested a meeting with the Renewable Energy Facilitation Office ("REFO") to seek help as the permitting timeline would make meeting the FIT contract deadlines impossible. A "*Renewable Energy Approval Proponent Pre-Submission Consultation Meeting*" request was faxed to the MOE on September 1, 2010. A meeting attended by Trout Creek, MNR, MOE and REFO was held September 8, 2010. Several concerns were discussed during this meeting:

- The Applicant needs to begin work on studies related to the REA, especially long lead-time studies such as bird studies; however the MNR would not permit this work as Applicant of Record status had not yet been issued.

- The timeline for submitting the revised wind testing proposal was uncertain as the MNR could not indicate how much time would be required to notify and consult Aboriginal communities.

Trout Creek has not been able to officially launch the REA process because it has not been granted Applicant of Record status. The delay that has been experienced in obtaining Applicant of Record status has compromised the ability of the Project to meet the milestones associated with the FIT contract. Detailed information regarding the issues with the MNR site release procedure and the REA is provided in Exhibits "G" and "H" to the Affidavit of Thomas Schneider (Exhibit B, Tab 1, Schedule 1).

It should be noted that these dates under the FIT Contract will be extended by 18 months as a result of *force majeure* applications to OPA. It is significant to note that OPA have recognized the significance of these delays which are acknowledged to be beyond the control of the Applicant. Therefore, the Applicant expects the new MDCO will be October 13th, 2014. A copy of the April 18, 2011 letter from the OPA regarding the delays may be found at Exhibit "F" to the Affidavit of Thomas Schneider (Exhibit B, Tab 1, Schedule 1).

Documentation of a complete REA is required as a pre-requisite to submitting a NTP Request. Working back from the NTP Request deadline and factoring in a possible six month

Environmental Review Tribunal hearing and six months for the Ministry of the Environment to coordinate the review of the REA and issue a decision, the REA will need to be submitted by October 2011, at the latest, in order to meet the NTP Request deadline.

Delays caused by regulatory authorities have affected the Project development timeline such that the FIT contract deadlines cannot be met. Specifically, the delay in obtaining Applicant of Record status has delayed the wind power testing phase of the Project, which is necessary to finalize the turbine locations and properly define the Project Location, which is the starting point of the natural heritage assessment, the cultural heritage assessment, and integral to the drafting of the Project Description Report. The OPA MDCO required that the Applicant have the all approvals for the wind power testing tower issued by end of 2010 and the tower installed and operational by early spring 2011 at the latest.

It is reasonable to expect to have the following completed in the next 12-18 months:

- Secure land use permit and work permit for installation and operation of the meteorological tower. 12 months
- Complete the requisite 1 year of audited wind data. 16 months
- Initiate and progress through the Renewable Energy Approval (REA) process.
    - Hold first of two required public meetings 12 months
    - Submit natural heritage assessment to MNR for review 18 months
    - Submit heritage assessment to Ministry of Culture for review 18 months
    - Finalize draft submission documents and be in a position to plan for final public meeting and application submission 18 months
- Initiate and progress through the Class EA process for the access road (coordinated with REA process). 12 months

c) Feed-In Tariff Contract

The FIT Contract, Exhibit B, Tab 11, prescribes certain milestone events for projects. For most projects, the MDCO is 3 years from executing the contract. Under the FIT program, the OPA retains the sole and absolute discretion to terminate any contract prior to the issuance of Notice To Proceed ("**NTP**"), pursuant to section 2.4(a) reproduced below.

2.4 Notice to Proceed

(a) Until the OPA issue Notice to Proceed to the Applicant, and the Applicant has provided to the OPA the Incremental NTP Security in accordance with 2.4(g), the OPA may terminate this Agreement in **its sole and absolute discretion** by notice to the Applicant and all Completion and Performance Security shall be returned or refunded (as applicable) to the Applicant within 20 Business Days following receipt of a written require for such return or refund (as applicable) from the Applicant.....

Therefore, prior to the issuance of NTP, Trout Creek is completely at risk for any monies paid in excess of any termination payment by the OPA. Lenders are justifiably hesitant to advance funding until assured the project will be constructed. The FIT Contract then provides the following list of prerequisites to being able to request NTP from the OPA.

Section 2.4 Notice to Proceed

(b) The OPA shall not issue Notice to Proceed in accordance with this Section 2.4 until the Applicant provides the OPA with an NTP Request in the Prescribed Form, and provided such NTP Request is complete in all respects. An NTP Request shall not be complete unless it includes all of the following (the "**NTP Pre-requisites**"):

(i) documentation of the completed Renewable Energy Approval, if applicable, and any other equivalent environmental and site plan approvals or permits necessary for the construction of the Contract Facility to commence;

(ii) a completed financing plan in the Prescribed Form, listing all sources of equity or debt financing for the development of the Contract Facility along with signed commitment letters from sources of financing representing collectively at least 50% of the expected development costs, stating their agreement in principle to provide the necessary financing, which commitment(s) may be conditional on the issuance of Notice to Proceed (the "**Financing Plan**");

(iii) where (A) the FIT Contract Cover Page identifies the Renewable Fuel of the Contract Facility as solar (PV) or (B) the FIT Contract Cover Page identifies the Renewable Fuel of the Contract Facility as wind power and the Contract Capacity is greater than 10kW, a plan in the Prescribed Form setting out how the Applicant intends to meet the Minimum Required Domestic Content Level (the "Domestic Content Plan"); and

(iv) documentation of the time and date of application for, and the completion of, all Impact Assessments required by the Distribution System Code or the Transmission System Code as applicable.

In order to make a request for NTP, a wind power developer is required to have completed the REA; provide a domestic content plan; provide a financing plan and have completed the necessary Impact Assessments. Without these three prerequisites, the developer is at risk the OPA may terminate the FIT Contract.

A FIT Contract is a prerequisite to obtaining debt financing for a project but is not a guarantee to having a lender commit to the project let alone advance funding. At the time the FIT Contract is issued the developer has its cost projections but not sufficient certainty to obtain debt. For wind projects, debt will most often be advanced after Notice to Proceed, once the proponent has satisfied subsequent permitting requirements and/or obtained tenure. In general, to obtain debt financing, the waterpower developer will need to have obtained:

(a) Connection Cost Estimate (+/-10 at construction);

(b) Construction Estimate based upon sufficiently advanced design to provide the required certainty;

(c) Permits;

(d) Tenure

Mr. Schneider, in his affidavit Exhibit B, Tab 1 Schedule 1, confirmed the delays in the MNR process do not permit Trout Creek to obtain funding and therefore are unable provide the full CCD payment at this specific time as required by the provisions of the DSC. Trout Creek is an experienced developer and confident the Project will proceed if the requested exemption is granted.

Witness: T. Schneider
W. Curtis

PART III. The Proposed Exemption

(i) The Proposed Exemption

Trout Creek has requested that the Board find the suggested amendment is in the public interest and amend Schedule 3 of the distribution license of Hydro One to include the following exemption:

1)

For the Trout Creek Wind Farm (Hydro One Project #12,780), Hydro One shall be exempted from the current connection cost deposit stipulated in s. 6.2.18(a) of the Distribution System Code (the "DSC) and shall, instead, adhere to the following schedule:

1. *$20,000 per MW of capacity shall be paid by the proponent to Hydro One upon the execution of the Connection Cost Agreement .*
2. *An additional deposit in the amount of 30% of the total estimated cost, as estimated by Hydro One, less the amount received by Hydro One under paragraph 1 above, shall be paid by the proponent to Hydro One no later than 4 months after the proponent notifies Hydro One that it has completed the Renewable Energy Approval.*
3. *No later than 180 days after Hydro One receives payment of the amount referenced in paragraph 2 above, Hydro One shall provide to the proponent a construction schedule and a more accurate estimate of the project cost, if such estimate is requested and paid for by the proponent. The payment for the estimate shall be drawn from the deposit to the extent possible.*
4. *The balance of the total estimated cost, as estimated by Hydro One based upon the best available information, shall be paid by the proponent to Hydro One no later than 30 days after the proponent notifies Hydro One that it is proceeding to construction.*
5. *Hydro One and the proponent shall mutually agree upon an in-service date that is no later than 2 years after Hydro One receives the balance referenced in paragraph 4, above, subject to the following: in cases where a transmission upgrade or new transmission facilities are required, Hydro One and the proponent may agree to an in-service date that is later than two years after Hydro One receives the balance referenced in paragraph 4, above.*

> 6. *The Expansion Deposit, as stipulated by Section 3.2.20 of the DSC shall be paid to Hydro One at the same time as the payment in paragraph 4.*

Notwithstanding the foregoing, if at any time the above-noted payments to Hydro One are insufficient to cover Hydro One's costs as estimated by Hydro One, the proponent shall pay, to Hydro One, additional funding sufficient to meet the shortfall identified by Hydro One, and Hydro One shall be relieved of its obligation to perform such further work until it receives the said additional funding.

Further, Trout Creek is of the view that this proposal is consistent with the principles that the distributor should not be at risk; that the generator pays its fair costs; and that the projects not unduly hold capacity allocations where the project is not progressing through to completion. The delays have been due to circumstances beyond the control of Trout Creek which has been recognized by the OPA.

(ii) The Distribution System Code

The DSC requires a distributor to enter into a connection cost agreement with a renewable generator within 6 months of having allocated capacity to the applicant. At the time the connection cost agreement is executed, the applicant generator must provide 100% of the estimated cost of connection. Failure to provide the necessary Connection Cost Estimate Deposit obligates the distributor to remove the allocated capacity. Loss of the allocated capacity may result in the termination of the project, and/or the loss of funds expended to date (the security deposit placed with the OPA). The relevant sections of the DSC are reproduced below:

> **6.2.4.**1 Subject to section 6.2.4.2, a distributor shall establish and maintain a capacity allocation process under which the distributor will process applications for the connection of embedded generation facilities. The capacity allocation process shall meet the following requirements:
>
> > e) an applicant shall have its capacity allocation removed if:
> >
> > i. a connection cost agreement has not been signed in relation to the connection of the embedded generation facility within 6 months of the date on which the applicant received a capacity allocation for the proposed embedded generation facility;......
>
> **6.2.18** A distributor shall enter into a connection cost agreement with an applicant in relation to a small embedded generation facility, a mid-sized embedded generation

facility or a large embedded generation facility. The connection cost agreement shall include the following:

a. a requirement that the applicant pay a connection cost deposit equal to 100% of the total estimated allocated cost of connection at the time the connection cost agreement is executed;

Trout Creek has been diligently moving the project through the development process as quickly as possible. At this time, the MNR has not been able to proivde Trout Creek a definitive timeline for completing its review. The FIT Contract includes provisions for Force Majeure events that may extend the Milestone Date for Commercial Operation as the OPA has recognized that certain events are beyond the control of the developer and the developer should not be harmed for such delays. Further, Trout Creek submits its circumstances are similar to that of the proponents in EB-2011-0067 where the Board accepted that an exemption would be available in certain circumstances.

While the FIT Contract and the CCA recognizes Force Majeure events may occur, there is no automatic connection to the timing obligations imposed by the DSC. Therefore, in the present case, the OPA has granted 6 months of Force Majeure events but there is no corresponding relief from the payment obligations of the DSC. This creates a disconnect for the developer such that obligations to make substantial payments are occurring much earlier in the development cycle and prior to lenders/financiers having sufficient comfort to advance monies.

Trout Creek does not wish to avoid any appropriate costs for connection or to place Hydro One and its ratepayers at any additional risks but rather wants to align Trout Creek's payment obligations with the regulatory process.

PART IV. The Test for Granting Amendments

(i) Public Interest Test

Trout Creek has requested the Board amend the license of Hydro One to provide an exemption to certain sections of the DSC. Trout Creek's concern is with the current process established by the DSC. No other distributor is impacted by the list of 27 projects so no other exemptions were requested. The authority of the Board to amend a license is established by Section 74(1)(b) of the OEB Act which permits any person to apply for an amendment to a license.

> 74.(1) The Board may, on the application of any person, amend a licence if it considers the amendment to be,
>
> (a) necessary to implement a directive issued under this Act; or
>
> (b) in the public interest, having regard to the objectives of the Board and the purposes of the *Electricity Act,*

The test applied by the Board in considering an amendment is whether the proposed amendment is in the public interest having regard to the purposes of the *Electricity Act, 1998*.[1] The "public interest" mandate of the Board is further informed by the objectives of the Board provided in section 1(1) of the OEB Act, the directly relevant sections of which are reproduced below:

> 1(1) The Board, in carrying out its responsibilities under this or any other Act in relation to electricity, shall be guided by the following objectives:
>
> 1. To protect the interests of consumers with respect to prices and the adequacy, reliability and quality of electricity service.
>
> 2. To promote economic efficiency and cost effectiveness in the generation, transmission, distribution, sale and demand management of electricity and to facilitate the maintenance of a financially viable electricity industry.
>
> 5. To promote the use and generation of electricity from renewable energy sources in a manner consistent with the policies of the Government of Ontario, including the timely expansion or reinforcement of transmission systems and distribution systems to accommodate the connection of renewable energy generation facilities.

[1] S.O. 1998, c.15, Schedule A.

> (2) In exercising its powers and performing its duties under this or any other Act in relation to electricity, the Board shall facilitate the implementation of all integrated power system plans approved under the *Electricity Act, 1998*.

As noted above the Board is to have regard to the purposes of the *Electricity Act*, the relevant of which are reproduced below.

> Electricity Act
>
> 1. The purposes of this Act,
> (a) to ensure the adequacy, safety, sustainability and reliability of electricity supply in Ontario through responsible planning and management of electricity resources, supply and demand;
> ....
> (d) to promote the use of cleaner energy sources and technologies, including alternative energy sources and renewable energy sources, in a manner consistent with the policies of the Government of Ontario;
> (e) to provide generators, retailers and consumers with non-discriminatory access to transmission and distribution systems in Ontario;
> (f) to protect the interests of consumers with respect to prices and the adequacy, reliability and quality of electricity service;
> (g) to promote economic efficiency and sustainability in the generation, transmission, distribution and sale of electricity;
> ....

The proposed exemption will enable the development of the Trout Creek Wind Farm and advance the public interest by ensuring electricity is generated from renewable energy sources in a cost effective manner.

The Long Term Energy Plan includes wind as a key element in the Ontario electricity supply mix.

> Renewable energy—wind, solar, hydro, and bioenergy — is an important part of the supply mix. Once the initial investment is made in equipment and infrastructure, fuel cost and greenhouse gas emissions are zero or very low. Renewable energy makes it possible to generate electricity in urban and rural areas where it was not feasible before.[2]

[2] Exhibit B, Tab, 1, Schedule 3, page 10.

> Ontario will continue to develop its renewable energy potential over the next decade. Based on the medium growth electricity demand outlook, a forecast of 10,700 MW of renewable capacity (wind, solar, and bioenergy) as part the supply mix by 2018 is anticipated. This forecast is based on planned transmission expansion, overall demand for electricity and the ability to integrate renewables into the system. This target will be equivalent to meeting the annual electricity requirements of two million homes.[3]

The Trout Creek Wind Farm will serve the public interest in the following ways:

- The Project will result in significant local investment and approximately * 16,400 hours of employment during construction. Schneider Power has a long-standing reputation of using local trades for its construction projects, whereas the balance of plant is anticipated to be built with a local materials and labour content in excess of 60%.

- The project will reduce transmission costs, increase grid stability and reliability for the end consumer as it is located between the two primary power generation hubs in southern and northern Ontario.

- The project has significant community support and involvement, including plans by the local chamber of commerce to use the facility as a tourist attraction – Trout Creek has been economically depressed ever since the Highway 11 bypass.

9390822.2

[3] Exhibit B, Tab 1, Schedule 3, page 31.

ONTARIO ENERGY BOARD

IN THE MATTER of the *Ontario Energy Board Act, 1998*, S.O. 1998, c.15, Schedule B;

AND IN THE MATTER a request for an order(s) pursuant to section 74(1)(b) amending the distribution license of Hydro One Networks Inc. to provide an exemption from compliance with sections 6.2.4.1(e) and 6.2.18(a) of the Distribution System Code in respect of the Trout Creek Wind Power Inc. for the Trout Creek Wind Farm (Hydro One Connection No. 12,780);

AFFIDAVIT OF THOMAS SCHNEIDER

I, **THOMAS SCHNEIDER** of the City of Toronto, Ontario, MAKE OATH AND SAY AS FOLLOWS:

1. I am the President of Trout Creek Wind Power Inc. ("**Trout Creek**") and Schneider Power Inc. ("**Schneider**") and as such have knowledge of the matters hereinafter deposed. Where a statement is based upon information and belief, I provide the source and believe the information to be true. Trout Creek is a wholly owned subsidiary of Schneider.

2. Schneider, a wholly owned subsidiary of Quantum Fuel Systems Technologies Worldwide Inc. (NASDAQ: QTWW), is one of North America's premier independent power producers focusing solely on renewable energy. Quantum Fuel Systems Technologies Worldwide Inc. owns and operates a portfolio of renewable electricity generation facilities in North America, and holds a minority interest in a wind facility in Germany.

3. Schneider has over 1,000MW of solar and wind projects in operation or development throughout the world.

4. The Project is located on lands controlled by the Government of Ontario and subject to the Ministry of Natural Resources' ("**MNR's**") site release process for windpower projects. A copy of the MNR's site release procedure is attached to this my affidavit as Exhibit "A".

5. Trout Creek applied to the MNR for release of the site for the Project on June 16, 2010. Trout Creek received applicant of record status on March 7^{th}, 2011 and is still awaiting the information from the MNR regarding which First Nations Trout Creek should consult with about the Project.

6. Trout Creek entered a Feed-In Tariff Contract with the Ontario Power Authority (the "**OPA**") dated April 30, 2010 for a 10MegaWatt ("**MW**") wind power project, the Trout Creek Windfarm ("**Project**").

7. The Project is identified by Hydro One Networks Inc. as project number 12,780. A copy of the electronic mail, dated May 12, 2011, attaching the Connection Cost Agreement is attached to this my affidavit as Exhibit "B".

8. The Project has not progressed through the site release procedure in accordance with the timeframes portrayed through no fault of Trout Creek. Trout Creek has actively pursued the release of the site and the development of the Project.

9. The electronic message confirms that Trout Creek is to provide a deposit of \$3,402,574.64 (the "**Deposit**") by 4:00 pm on May 26, 2011. I believe that failure to make payment, in the absence of relief sought from the Ontario Energy Board as part of

the motion, will result in the Project losing its capacity allocation and the end of the Project.

10. Schneider cannot secure the Deposit at this stage of the development of the Project because the Project has not progressed sufficiently through the MNR site release procedure. Schneider does not have a site control agreement which is a requirement normally used as collateral for a loan or investment for relevant development expenditures or deposits. Schneider does not have a complete wind study on Crown Land which is used a proof that the land has a sufficient wind resource.

11. Without the relief requested, Schneider is currently at risk of being in default with the DSC, requiring a risk, and/or subsequent events disclosure that would prevent further investment by third parties.

12. Counsel to Trout Creek wrote to the Ontario Energy Board on April 14, 2011 and on May 9, 2011 regarding a relief from the timing provisions of the Distribution System Code. A response from the Ontario Energy Board was received May 13, 2011. Copies of the letters are attached to this my affidavit as Exhibits "C", "D" and "E" respectively.

13. In April 2011, Schneider received correspondence from the Ontario Power Authority confirming that the Project had been the subject of almost 6 months of Force Majeure events under the Feed-In Tariff Contract and, as such, extended the Milestone Date for Commercial Operation by a corresponding number of days. In addition, the Ontario Power Authority extended the Milestone Date for Commercial Operation by an additional 1 year period. A copy of the letter from the Ontario Power Authority confirming the statements regarding Force Majeure and the materials filed by Trout Creek in support of such are attached to this my affidavit as Exhibits "F", "G" and "H".

14. I make this affidavit in support of the motion brought by Trout Creek Power Inc. and for no improper purpose.

Sworn before at Toronto,	)	
	)	
Ontario, this 25th day of May, 2011.	)	
	)	
	)	
A Commissioner for Taking Affidavits		

KEVIN FREDRICK WENTZEL, a
Commissioner, etc., Province of Ontario,
while a Student-at-Law.
Expires April 29, 2014.

The attached is **Exhibit "A"** to the Affidavit of
Thomas Schneider, sworn before me
this 25th day of May, 2011

A Commissioner, etc.

KEVIN FREDRICK WENTZEL, a
Commissioner, etc., Province of Ontario,
while a Student-at-Law.
Expires April 29, 2014.

Ministry of Natural Resources

Ontario

Subject **ONSHORE WINDPOWER DEVELOPMENT ON CROWN LAND – NON-COMPETITIVE APPLICATION**		Procedure **PL 4.10.04**	
Compiled by Renewable Energy Program		Date Issued July 5, 2010	
Replaces Directive Title Same	Number Same	Dated January 28, 2008	Page 1 of 18

This document provides procedural direction to implement Policy PL 4.10.04 Onshore Windpower Development on Crown Land.

1.0 WINDPOWER APPLICATION

1.1 Application for Crown Land

Prior to submitting an application, Applicants are strongly encouraged to undertake pre-consultation with the Ministry District Office and Applicants should review all available planning and information tools available online including the: Crown Land Use Policy Atlas, Ministry of Northern Development, Mining and Forestry (MNDMF) website (e.g. Claim maps) and the Ministry's Renewable Energy Atlas.

Applicant initiated requests to change grid cells configurations that are not based on recommendations and/or advice from the Ministry, will be subject to an administrative fee. Addition of Crown land to existing applications will not be permitted and will require a new application.

a) Applicants will submit the following information to the Renewable Energy Program, in the prescribed manner:

- Windpower Application for Crown Land;
- grid cell maps; and
- application fee (non-refundable) cheque made payable to the Minister of Finance.

Ministry District or Regional offices, or Zone offices cannot accept and/or date stamp a windpower application.

b) A maximum of 44 contiguous grid cells may be applied for with a single application. An Applicant must be an individual or a legal entity that is eligible to hold land in Ontario.

c) In certain cases (e.g. complex terrain), up to three non-contiguous grid cell groupings in close proximity may be considered as one application, although they may total no more that 44 grid cells. To qualify for this consideration, the Applicant must provide written rationale such as: the excluded area between requested cell groups has no commercial wind energy potential or that it is the intent of the Applicant to have a contiguous windpower project and the excluded lands are not Crown lands, but lands that the Applicant has secured rights to.

d) The Business Process Officer (BPO) will upon receipt, record the date and time stamp on all maps and applications. Applications must be received by the BPO in the manner prescribed by the Ministry, to be considered valid.

1.1.1 Application Receipt

The BPO will:

a) Receive the Windpower Application for Crown Land package and application fee;

b) Review the application for completeness and ensure that there are no cells overlapping with existing applications and advise the Applicant accordingly;

c) Verify that the grid cells requested have been identified correctly and enter location of the grid cell group into the Renewable Energy Allocation Tracking System (TREATS) database;

d) Forward hard copies of the applications and maps to the applicable Ministry District office(s) with copies to Renewable Energy Coordinators (RECs), the Provincial Mining Recorder and other relevant agencies. Electronic versions of grid cells (including date received) are also sent to the District office, the Ministry Land Management Section for identification in land tenure databases, and the Mining Recorder's office, for recording as a pending disposition under the Public Lands Act. Where a single application is geographically situated within more than one Ministry administrative district, a lead District will be determined. Ontario Parks Zone Managers will be notified where appropriate; and

e) Process the non-refundable application fee within 30 days of receiving the application.

1.2 Application Review

Upon receiving the date stamped Windpower Application for Crown Land form and grid cell map(s) from the BPO, the District will:

a) Complete an initial Ministry review of the application based on natural resource values mapping (e.g. NRVIS) land tenure information, land use direction contained within the Crown Land Use Policy Atlas and other relevant information sources to identify areas where land use policies or other values may prohibit or limit windpower development and associated infrastructure development (e.g. transmission corridors and roads).

Advise the Applicant of areas where development may be limited or prohibited due to statutory, regulation or land use policy, as per Section 2.0 of the Onshore Windpower Development on Crown Land policy, and what parts of the application would be denied.

b) Notify Aboriginal communities of the application for windpower grid cells, to seek initial response and feedback. The Ministry will work with the Ministry of the Environment and other ministries and/or agencies to determine the list of Aboriginal communities to notify.

c) Within 60 days of receiving the application, the Ministry will prepare a Site Information Package (SIP) for the Applicant.

The site information package will include any known information that the Ministry has within at least 550 metres of the proposed windpower project, the list of Aboriginal communities, and identification of other sources of information that the Applicant should review to assist in making their decision on proceeding with a proposal.

d) Within 30 days of the delivery of the site information package, the Ministry will hold a site information meeting with the Applicant. The purpose of this meeting will be to review the SIP and other information the Applicant has obtained relative to the site, as well as to outline the full scope of the process involved in developing a windpower project on Crown land.

Applicants are encouraged to identify transmission and access corridor requirements. District staff may wish to consider accepting an Application for Crown land for these lands. Where applicable, Applicants should be advised that easements or other tenure may be required within the area they have applied for, to ensure access and transmission for other developments. Adjoining windpower Applicants will be encouraged to share access and transmission corridors.

1.3 Applicant Decision to Proceed

Within 30 days of the site information meeting, the Applicant must submit the Windpower Applicant Declaration Form confirming in writing with the District that they wish to proceed. Should the Applicant decline to proceed, or fail to respond in 30 days, the site will be made available to other Applicants and the District will notify the REC, BPO, Aboriginal community(ies) and any other agency previously informed of the application.

1.3.1 Aboriginal Notification

Upon receipt of notification from the Applicant to proceed with a windpower testing project or windpower project, the District will notify Aboriginal communities identified through the process in 1.2.(b). Any information received by the Ministry from Aboriginal communities will be forwarded to the Applicant and addressed as part of the consultation report, consistent with the Renewable Energy Approval regulation and Approval and Permitting Requirements Document.

1.3.2 Public and Municipal Notification

The Applicant will conduct public notification within 60 days of submitting the Windpower Application Declaration Form.

The public notification will at a minimum, consist of an advertisement placed in local newspaper(s), with the intent of ensuring sufficient notice to local residents. Notification will include the following:

- contact information, including Applicant and/or company name;
- full mailing address, including postal code and telephone number;
- map and description of the application area (lots, concessions, township);
- description of the project proposal (testing or development);
- invitation to provide comments on the project, specifying the deadlines (30 day period);
- optional additional information (e.g. background, company information, etc.); and
- where the project is proposed within a provincial park or conservation reserve, and is permitted as per section 19 of the Provincial Parks and Conservation Reserves Act, notification will include the name of the protected area and the exception that applies.

The Applicant is responsible for providing the District in advance, with the date that the notification will appear in the newspaper(s) and a copy of the advertisement. The District will inform the BPO of this date.

Public notification will have different content depending upon the activity:

- when windpower testing is being conducted, the notice will indicate that the installation of windpower testing facilities is being proposed for the purpose of determining the viability of the wind resources in the area; and
- where no wind testing is to be conducted, the public notification will indicate that a windpower development is being proposed.

Feedback from the public notification will form part of the consultation report, which will be reviewed by the government as part of the review of a windpower project, consistent with the Renewable Energy Approval regulation and the Approval and Permitting Requirements Document.

In addition, the District will advise local municipality(ies) and conservation authority(ies) of the application.

1.3.3 Applicant of Record Status

Following Aboriginal and public notification, the District Manager will either issue the Applicant of Record letter or deny issuance of the Applicant of Record letter, based on legislative, regulatory or policy reasons.

If the decision is made to issue the Applicant of Record letter, the District will request, collect, and processes payment of the grid cell fees plus bid fees / non-competitive fees and issue the Applicant of Record letter with a copy to the REC and BPO. These fees are non-refundable and subject to applicable taxes.

The Applicant of Record letter grants the Applicant the ability to pursue required approvals and permits for development of a windpower testing project or a windpower project.

The Applicant of Record letter will include milestones related to development of the windpower testing project and/or a windpower project. Provided established timelines are followed, the Applicant will continue to be recognized by the Ministry as the Applicant of Record associated with a grid cell or grid cell grouping as identified in the Windpower Declaration Form.

If at anytime through the process the Applicant makes a decision to withdrawal from the site, they will advise the District in writing. A copy of this correspondence will be forwarded to the REC and BPO. The BPO will advise the Mining Recorder

2.0 PORTABLE TESTING EQUIPMENT

Prior to the completion of the application process, Applicants may undertake wind resource testing on Crown land using portable testing equipment (i.e. trailers or other vehicles). The Ministry's Approval and Permitting Requirements Document for complete submission establishes requirements for windpower testing projects.

3.0 MAINTAINING APPLICANT OF RECORD STATUS

Once Applicant of Record status is awarded, the Applicant will be subject to various milestones and reporting requirements to ensure that projects are progressing through the subsequent development processes within reasonable timelines.

These milestones will ensure that Crown land identified for potential renewable energy projects is not being unduly occupied over the long term without development proceeding and thereby impacting the ability of the area to be used for other purposes.

Where an Applicant does not meet the milestones established to maintain Applicant of Record status, the District Manager may cancel the applicant of record status with 30 days notice, and make the identified grid cells available for other Crown land management activities, including other applications for renewable energy projects.

3.1 Milestones - Testing Facilities on Crown Land

Where an Applicant has identified to the Ministry that they wish to pursue approvals for a windpower testing project on Crown land, the following milestones will apply:

a) Within 180 days of receiving the Applicant of Record letter, an Applicant must submit a complete submission for the windpower testing project, consistent with the Ministry's Approval and Permitting Requirements Document;

b) Within 180 days of the issuance of all of the required approvals and permits the Applicant will install the windpower testing project;

c) Within 1080 days (approximately three years) of installing the windpower testing project, the Applicant will need to demonstrate suitable procurement such as an accepted Feed-In Tariff application or a power purchase agreement. The Ministry will review the procurement application/agreement to ensure that the proposed energy production of the facility reasonably optimizes the geography applied for; and

d) Once an Applicant of Record has completed testing and demonstrated suitable procurement, they will provide written annual updates to the District Manager. Where reasonable progress has not been made, the Ministry may cancel the Applicant of Record status with 30 days notice.

The Ministry may grant extensions to testing timelines in exceptional circumstances, supported by documentation of the rationale for the extension.

The Applicant of Record may decide at any time during the testing period that they wish to proceed with the development of a windpower project.

Applicants may choose to begin some preliminary work related to other approvals and permits during the testing period, such as conducting baseline flora and fauna studies. This work would be conducted in accordance with any applicable policies, procedures or guidelines and with input from the Ministry and other applicable agencies. As the full scope of the project has not yet been identified, Applicants should be advised that any work done at this stage may not fully satisfy the requirements of the Ministry or other agencies.

Wind testing equipment on Crown land will be authorized by a land use permit, with annual rent paid in accordance with the Crown Land Rental Policy PL 6.01.02.

Prior to completion of the testing phase, the Applicant will in accordance with the terms of their Applicant of Record letter, provide the District with written confirmation of whether they wish to proceed with development of a windpower project.

3.2 Milestones - Testing on Adjacent Private Land

Where the Windpower Application Declaration Form indicates that the Applicant will seek to develop a windpower testing project on adjacent private land, the Applicant will still be subject to the timelines established in Section 3.1 to remain the Applicant of Record associated with a grid cell or grid cell grouping.

3.3 Milestones - No Windpower Testing

Where an Applicant identifies in their Windpower Application Declaration Form that they do not wish to undertake windpower testing (Crown or adjacent private), the Applicant will have one year from the time the Applicant of Record letter is received to demonstrate suitable procurement, that generally being an accepted Feed-In Tariff application or a power purchase agreement. The Ministry will review the procurement application/agreement to ensure that the proposed energy production of the facility reasonably optimizes the geography applied for.

Once an Applicant has demonstrated suitable procurement, they will provide written annual updates on the status of the project to the District Manager. Where reasonable progress has not been made, cancellation of the application may result with 30 days notice.

4.0 RENEWABLE ENERGY APPROVAL PROCESSES

Windpower projects are generally subject to the renewable energy approval process established under the Environmental Protection Act and the Ministry's Approval and Permitting Requirements Document for Renewable Energy Projects.

5.0 SURVEY REQUIREMENTS, TENURE AND RENT

Following the Ministry's decision to proceed with the necessary permits and approvals, the District will instruct the Applicant of Record to submit an application for Crown land and a current corporate profile from the jurisdiction in which they were incorporated. The Ministry will also provide survey instructions to the Applicant of Record.

5.1 Survey Requirements

The following survey options may be directed by the Ministry:

1. where there are large distances between the turbines, individual turbine locations may be surveyed as separate parts on the survey plan for inclusion in the lease;

2. where the turbines occupy a small area and/or are located in close proximity to each other, these areas may be surveyed as one part on the survey plan for inclusion in the lease; and

3. where there are clusters of turbines occupying small areas and/or they are located in close proximity to each other, these areas may be surveyed as separate parts for inclusion in the lease.

Survey instructions should give consideration to public safety and/or potential encroachment onto adjacent lands (e.g. area under tenure should ensure that if a turbine were to collapse, no part of the turbine, including the blades, would encroach onto adjacent lands) and the areas surveyed should generally not be larger than needed to meet these needs. The District will consult with the Office of the Surveyor General prior to issuing survey instructions.

Easements required for electrical collector lines between the turbines shall be surveyed as separate parts on the survey plan.

The Applicant will obtain an approved Crown land survey consistent with PL 2.06.01 Survey Plan Approval. The Applicant will be responsible for the procurement and costs of a survey and Crown land plan preparation and registration by an Ontario Land Surveyor. The District must issue survey instructions prior to any surveying of Crown land.

Grid cells or parts of grid cells not under Crown tenure, may be made available for other Crown land management activities.

5.2 Tenure

Authorization to construct and develop a windpower project will be by a Crown lease. The term of these leases will generally be for 25 years, with one possible extension for an additional term of 15 years.

Where survey requirements have not been completed prior to construction, a land use permit may be issued as interim authority for a maximum term of one year. The land use permit will contain conditions clearly indicating that the permit is an interim authority only.

Separate tenure documents or approvals (e.g. land use permits, easements, patents, work permits, aggregates permits/licenses, agreements, memorandums of understanding) will be issued for utility corridors, transformer stations, access roads and any other infrastructure required beyond the leased area. Fees for these documents or permits will be established through applicable policy.

To ensure orderly management of Crown land, the District may request a surface rights withdrawal of the unalienated Crown lands between the turbines where alienation of the surface rights for mining activities would be incompatible with operation of a windpower project.

Issuance of permits or tenure documents, as well as associated fees, will comply with the appropriate directives including:

- PL 3.03.04 Public Lands Act Work Permits
- PL 4.02.01 Application Review and Land Disposition Process
- PL 4.10.03 Utility Corridor Management
- PL 4.10.04 Onshore Windpower Development on Crown Land
- PL 4.11.04 Easements (Grants of)
- PL 6.01.02 Crown Land Rental Policy

Tenure documents associated with the Crown lease for wind turbines should run concurrently with the Crown lease.

When the routing and requisition package is prepared by the District, a cover page must be affixed stating: THIS IS RELATED TO A RENEWABLE ENERGY PROJECT, to ensure that appropriate Renewable Energy staff are aware.

The purpose section on all requisitions must clearly identify that the tenure is for windpower purposes (e.g. "to authorize a windpower project", "to authorize electrical collector lines associated with a windpower project.").

Following preparation of a tenure document (other than a land use permit), the Crown Land Registry will advise MNDMF of its issuance by copy of the document. Geographic Information Branch will provide MNDMF with an electronic version of the surveyed area.

The Renewable Energy Program will ensure that the appropriate databases are updated and that the notification status with MNDMF is updated as appropriate.

The District will submit the necessary documentation to MNDMF related to any required surface rights withdrawal, consistent with PL 3.03.03 Withdrawal and Reopening of Surface and/or Mining Rights - Section 35, Mining Act.

5.3 Fees and Rents

In addition to fees and rents established in Ministry Crown land management policies, there are several rents and fees specifically associated with windpower testing and windpower development (Appendix B).

5.4 Reconfiguration of Applications

Reconfiguration of applications will be allowed in the following circumstances:

- request will result in the application area becoming smaller;
- request will result in the amalgamation and/or splitting of applications where the applications are in the exact same name and there will be no new grid cells from those in the original applications; and
- request is submitted following submission of the Windpower Applicant Declaration Form and all required fees as outlined in Appendix B.

The Ministry will not consider requests from Applicants to include new grid cells in the area of their application. Any such requests must be submitted through an open window, using the application process outlined in this Procedure.

6.0 REFERENCES

6.1 Statutory

- Endangered Species Act
- Environmental Protection Act
- Freedom of Information and Protection of Privacy Act
- Lakes and Rivers Improvement Act
- Mining Act
- Provincial Parks and Conservation Reserves Act

- Public Lands Act
- Renewable Energy Approval Regulation (O. Reg. 359/09) MOE 2009
- Wilderness Areas Act

6.2 Policies and Procedures

- Approval and Permitting Requirements Document for Renewable Energy Projects (APRD) (MNR 2009)
- PL 2.06.01 Survey Plan Approval Policy
- PL 4.10.03 Utility Corridor Management
- PL 4.10.04 Onshore Windpower Development on Crown Land (Policy)
- PL 4.11.04 Easements (Grants of)
- PL 6.01.02 Crown Land Rental Policy

APPENDIX A - Grid Cell Description

This appendix shall not to be used for the purposes of describing a lease document or other document to be registered in the Land Registry Office. Such a document requires a legal description and therefore must comply with the applicable requirements as set out in the "INSTRUCTIONS GOVERNING ONTARIO CROWN LAND SURVEYS AND PLANS, June 1, 1998" and in appropriate acts and regulations.

The following guidelines relate to grid cells for wind testing:

1. The Province of Ontario shall be divided into grid areas to be known as grid cells.

2. A grid cell shall be bounded by lines of geographic latitudes and longitudes based on the NAD 83 (CSRS98) datum.

3. Grid cell limits shall be set using latitudes and longitudes in increments of 30 seconds of the series 50° 00' 00", 50° 00' 30", 50° 01' 00", 50° 01' 30", which series may be extended as required. This also determines the numerical sequencing for grid cells.

4. The area of a grid cell will vary depending on the latitude and longitude, but generally will be within 45 hectares to 65 hectares.

5. Every grid cell shall be referred to by its reference number contained within the grid cell.

6. A windpower application may consist of one or more contiguous grid cells, to a maximum of 44 contiguous grid cells per application.

7. Grid cells that only have one common corner are not deemed to be contiguous.

8. In certain cases (e.g. complex terrain), up to three non-contiguous grid groups in close proximity, totalling no more that 44 grid cells, may be considered as one grid group.

9. A grid cell shall not be further subdivided.

10. All Applicants are required to follow the mapping instructions outlined in the Renewable Energy internet site.

APPENDIX B - Windpower Fees and Rents

Application Fee: This fee supports the Ministry's administrative costs associated with the environmental review, competitive bid processes, geographic information services and related application and review. This non-refundable fee (except in the case of unsuccessful bidders through a competitive process) is payable by all Applicants under all application methods upon receipt of the application.

Administrative Fee: A fee will apply for completing transactions, such as making changes to applications.

Base Land Rent: A base land rent will be applied to the area under the land use permit (if applicable) and under the subsequent Crown lease. This rent is payable annually at the beginning of the calendar year and will be applied until January 1, 2012, when the Wind Land Rental Charge and Administrative Base Land Rent become effective and payable.

- **During the testing period**: fee will be based on the Crown land rental policy, for the footprint of the testing facility.
- **During the development period:** the Ministry commissioned zonal appraisal reports will be used to set a land value per hectare. The base land rent shall be reviewed and adjusted based on the review of the zonal value average for the applicable zone.

Grid Cell Fee: This fee is paid for the opportunity to be recognized as the Applicant of Record on the lands applied for and to pursue wind testing and approvals for that area.

Non-Competitive Opportunity to Explore Fee: Paid by Applicants in the non-competitive application process. This fee does not apply to off-grid communities.

Competitive Bid Value: Paid by Applicants in the Ministry initiated competitive bid process. The bid value is the amount that is bid above the minimum grid cell (or tract) fee.

Wind Land Rental Charge: This rental charge will come into effect on January 01, 2012 and is based on the total installed kilowatt capacity (the manufacturer's rated power capacity) of all turbines in the project.

The Wind Land Rental Charge will not be applied to an off-grid community.

The charge is paid in quarterly instalments, through the calendar year.

Administrative Base Land Rent: An annual administrative base land fee, plus applicable taxes, for the grid cell grouping will replace the base land rent and will be applied in addition to the Wind Land Rental Charge, when the Land Rental Charge is implemented effective January 1, 2012.

The combined payment of the administrative base land rental and the wind land rental charge is intended to capture rental payment for an area as described in Section 5.1 (Survey Requirements) of this procedure. Should an Applicant make a business case for a larger area, additional rent, based on zonal values would apply to the associated tenure document.

Windpower Rents and Fees

Charge / Rent	Non-Competitive Opportunity to Explore		Competitive Bid		Off-Grid Communities	
	Testing	Production	Testing	Production	Testing	Production
Application Fee	$1,000.+ tax -paid at time of application		$1,000 + tax -non-refundable (unless unsuccessful) -paid at time of bid		$1,000 + tax -paid at time of application	
Non-Competitive Opportunity to Explore Fee	$20,000.00 (includes tax)					
Grid Cell Fee	$300 per grid cell or $1200 per tract (+tax)		Minimum bid amount = $300 per grid cell or $1200 per tract (+tax)		$300 per grid cell or $1200 per tract (+tax)	
Base Land Rent	Based on Crown land rental policy for footprint of testing equipment	Based on zonal values -Paid annually until 2012	Based on Crown land rental policy for footprint of testing equipment	Based on zonal values -Paid annually until 2012	Based on Crown land rental policy for footprint of testing equipment	Based on zonal values -Paid annually.
Wind Land Rental Charge		Based on revenue potential of wind farm. -Paid annually beginning 2012		Based on revenue potential of wind farm. -Paid annually beginning 2012	N/A	N/A
Administrative Base Land Rent		$1,000 (+tax) -Paid annually beginning 2012		$1,000 (+tax) -Paid annually beginning 2012	N/A	N/A
Administrative fees related to such transactions as consent to mortgage, transfers and application alterations	$200 (+tax)	$200 (+tax)	$200 (+tax)	$200 (+tax)	$200 (+tax)	$200 (+tax)

APPENDIX C - Mining Rights and Oil and Gas Leases

The information provided below provides guidance only and is not intended as legal advice. Further direction should be sought from Ministry and MNDMF staff.

It is the responsibility of the Applicant to fully investigate the status of the lands that they are applying for and to negotiate any required agreements with tenure or claim holders.

Staked Mining Claim

Staked prior to windpower application: Mining claim holder has a first right of refusal to the surface rights, pursuant to Section 50 of the Mining Act. The windpower Applicant must obtain the consent of the claim holder and have them release the rights to the surface. Written release must be filed in the Provincial Recording Office, of MNDMF in the prescribed manner.

If the mining claim holder will not release the right, the matter may be referred to the Mining and Lands Commissioner.

Should a mining claim holder release their rights to the surface, they retain the right to proceed with mineral exploration work. The windpower Applicant must ensure that they do not cause any damage to any exploration workings or claim posts installed by the claim holder. Damage to exploration work is subject to compensation pursuant to Section 79(3) of the Mining Act. The mining claim holder must ensure that they do not cause any damage to any installations made by the windpower Applicant. The mining claim holder is subject to compensation to the windpower Applicant pursuant to Section 79(2) of the Mining Act. Both the windpower Applicant and the mining claim holder have the right to pursue their respective interests.

Staked after the windpower application: Pursuant to Section 28(2) and (3) of the Mining Act, the mining claim holder is subject to the prior application made under the Public Lands Act and the windpower application may proceed.

Mining Claim holders will be included as stakeholders in the stakeholder consultation.

The mining claim holder has the right to proceed with mineral exploration work. The windpower Applicant must ensure that they do not cause any damage to any exploration workings or claim posts installed by the claim holder. Damage to exploration work is subject to compensation pursuant to Section 79(3) of the Mining Act. The mining claim holder must ensure that they do not cause any damage to any installations made by the windpower Applicant. The mining claim holder is subject to compensation to the windpower Applicant pursuant to Section 79(2) of the Mining Act. Both the windpower Applicant and the mining claim holder have the right to pursue their respective interests.

Mining Leases

Surface and Mining Rights Lease: The windpower Applicant is encouraged to work with the holder of the mining lease to come to an agreement that would allow for the windpower Applicant to proceed.

In some circumstances, the Crown may have an opportunity to exercise rights under the Mining Act to enable the windpower application to proceed.

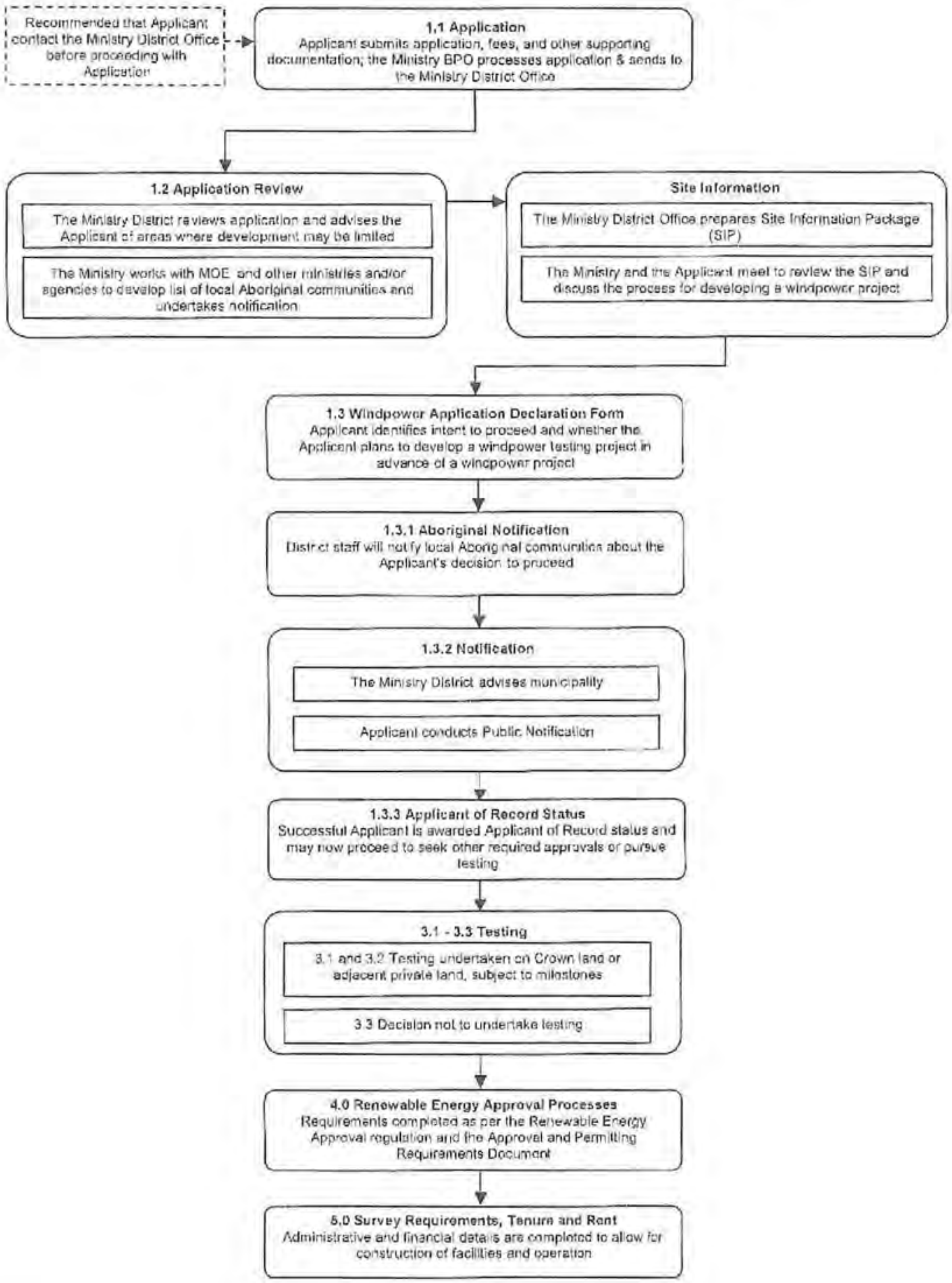
Mining Rights Lease: the Ministry can issue a surface rights lease for the Windpower project. The windpower Applicant and the mining rights holder would have to work together to come to an agreement regarding the use of the surface to access the land and must ensure that no damage is caused to the installations or workings of either party, subject to Section 79 of the Mining Act.

Oil and Gas Leases:

The windpower Applicant is encouraged to work with the holder of the oil and gas lease to come to an agreement that would allow for the windpower Applicant to proceed.

In some circumstances, the Crown may have an opportunity to exercise rights under the Mining Act to enable the windpower application to proceed.

APPENDIX D - Windpower Application Process



The attached is **Exhibit "B"** to the Affidavit of
Thomas Schneider, sworn before me
this 25th day of May, 2011

A Commissioner, etc.

KEVIN FREDRICK WENTZEL, a
Commissioner, etc., Province of Ontario,
while a Student-at-Law.
Expires April 29, 2014.

Connection Cost Agreement

between

Trout Creek Wind Power Inc.

and

Hydro One Networks Inc.

FOR

THE CONNECTION OF A 10 MW GENERATION FACILITY TO HYDRO ONE'S DISTRIBUTION SYSTEM

Trout Creek Wind Power Inc. (the "**Generator**") has requested and Hydro One Networks Inc. ("**Hydro One**") is agreeable to performing the work required to connect the Generation Facility to Hydro One's distribution system at the Point of Common Coupling on the terms and conditions set forth in this **Connection Cost Agreement** which includes Schedules "A" (Scope of Work), "B" (Generator Connection Work), "C" (Estimated Allocated Cost of Connection and Miscellaneous), "D" (Offer to Connect); and "E" (Allocated Cost of Connection Statement) and the Standard Terms and Conditions V2011-1 (the "**Standard Terms and Conditions**") attached hereto (collectively, the "**Agreement**").

I. Representations and Warranties

The Generator represents and warrants to Hydro One as follows, and acknowledges that Hydro One is relying on such representations and warranties without independent inquiry in entering into this Agreement:

(a) the Generation Facility is fully and accurately described in the Application;
(b) all information in the Application is true and correct;
(c) if the Generator is a corporation or other form of business entity, the Generator is duly incorporated, formed or registered (as applicable) under the laws of its jurisdiction of incorporation, formation or registration (as applicable);
(d) the Generator has all necessary power, authority and capacity to enter into this Agreement and to perform its obligations under this Agreement;
(e) this Agreement constitutes a legal and binding obligation on the Generator, enforceable against the Generator in accordance with its terms;
(f) any individual signing this Agreement on behalf of the Generator has been duly authorized by the Generator to sign this Agreement and has the full power and authority to bind the Generator; and
(c) it is registered for purposes of Part IX of the *Excise Tax Act* (Canada) and its HST registration number is 843485764 RT0001.

Hydro One represents and warrants to the Generator as follows, and acknowledges that the Generator is relying on such representations and warranties without independent inquiry in entering into this Agreement:

(a) Hydro One is duly incorporated under the laws of Ontario;
(b) Hydro One has all necessary power, authority and capacity to enter into this Agreement and to perform its obligations under this Agreement;
(c) this Agreement constitutes a legal and binding obligation on Hydro One, enforceable against Hydro One in accordance with its terms; and
(d) any individual signing this Agreement on behalf of Hydro One has been duly authorized by Hydro One to sign this Agreement and has the full power and authority to bind Hydro One; and
(e) it is registered for purposes of Part IX of the *Excise Tax Act* (Canada) and its HST number is 87086-5821 RT0001.

II. Except as expressly set out in this Agreement, this Agreement shall be in full force and effect and binding on the parties upon the date that this Agreement was executed by Hydro One and shall expire on the date that is after the latest of:

(a) Hydro One performing all of the Hydro One Connection Work;
(b) the Generator paying all amounts required to be paid by the Generator under the terms of this Agreement; and
(c) where applicable, Hydro One refunding the Deposits in accordance with the terms of this Agreement (the "**Term**").

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For greater certainty, Hydro One shall not be obligated to execute this Agreement until such time as the Generator has paid all amounts required to be paid by the Generator upon the execution of this Agreement by the Generator, including, the Connection Cost Deposit.

Termination of this Agreement for any reason shall not affect the liabilities of either party that were incurred or arose under this Agreement prior to the time of termination. Termination of this Agreement for any reason shall be without prejudice to the right of the terminating Party to pursue all legal and equitable remedies that may be available to it including, but not limited to, injunctive relief.

III. Permitted Deviations and Exceptions to Mandatory TIR Requirements

The following are the only deviations from and exceptions to Hydro One's "Distributed Generation Technical Interconnection Requirements: Interconnections at Voltages 50kV and Below" (the "**TIR**") that Hydro One has accepted in respect of the Connection of this Generation Facility and a description of the alternatives that Hydro One has accepted and the work that the Generator has agreed to perform in consideration of Hydro One accepting such deviations and exceptions:

None

IV. Any notice, demand, consent, request or other communication required or permitted to be given or made under or in relation to the Agreement shall be given or made: by courier or other personal form of delivery; by registered mail; by facsimile; or by electronic mail. Notices to the Generator shall be addressed to Thomas Schneider, mailing address: 49 Bathurst Street, Suite 101, Toronto, ON M5V 2P2, e-mail address: t.s@schneiderpower.com and telephone number: (416)847-3724 Notices to Hydro One shall be addressed to to the Business Customer Centre (BCC), Attn: Generation Connection Application, 185 Clegg Road, Markham, Ontario, L6G 1B7, e-mail address: dxgenerationconnections@hydroone.com, telephone number: 1-877-447-4412 (select option 2).

A notice, demand, consent, request or other communication shall be deemed to have been made as follows:

(a) where given or made by courier or other form of personal delivery, on the date of receipt;
(b) where given or made by registered mail, on the sixth day following the date of mailing;
(c) where given or made by facsimile, on the day and at the time of transmission as indicated on the sender's facsimile transmission report; and
(d) where given or made by electronic mail, on the day and at the time when the notice, demand, consent, request or other communication is recorded by the sender's electronic communications system as having been received at the electronic mail destination.

V. The Generator acknowledges and agrees that the Generator has read and understands Section 6.2.4.1 of the Code. Furthermore unless the Generation Facility is a Capacity Allocation Exempt Small Embedded Generation Facility or the Generator is not an Embedded Retail Generator, the Generator acknowledges and agrees that upon the occurrence of any of the events described in Subsection 6.2.4.1e ii., iii., iv. and v. of the Code or the termination or cancellation of the Project:

(a) Hydro One shall remove the Generator's capacity allocation;

(b) the Generator's Capacity Allocation Deposit and/or any Additional Capacity Allocation Deposit paid pursuant to the terms of this Agreement are hereby forfeited by the Generator and will be retained by Hydro One in a deferral account for disposition by the OEB; and

(c) this Agreement will be deemed to be terminated and any unspent Connection Cost Deposit will be returned to the Generator in accordance with Section 19 of the Standard Terms and Conditions.

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For the purposes of Subsection 6.2.4.1e.v of the Code, a default of this Agreement shall include a Generator Default. Hydro One shall give the Generator written notice of a Generator Default and allow the Generator 30 calendar days from the date of receipt of the notice to rectify the Generator Default, at the Generator's sole expense.

VI. Large Embedded Generation Facility

Where the Generation Facility is a Large Embedded Generation Facility, the following terms apply:

Once the IESO has completed the System Impact Assessment and Hydro One's transmission business unit has completed the Customer Impact Assessment in respect of the proposed connection of the Generation Facility to Hydro One's distribution system, Hydro One will have Hydro One's transmission business unit perform an estimate study to delineate the scope of work of the Upgrade Work and provide an estimate of the Upgrade Costs (the "**TX Estimate Study**"), at the Customer's expense. By no later than 30 days after Hydro One's business unit has delivered the results of the TX Estimate Study, Hydro One shall deliver to the Customer new Schedules "A", "B" and "C" (the "**New Schedules**") to replace Schedules "A", "B" and "C" attached hereto. The New Schedules shall be made a part hereof as though they had been originally incorporated into the Agreement.

By no later than 20 days after the New Schedules have been delivered to the Customer (the "**20-Day Period**"), the Customer shall increase the Connection Cost Deposit the Customer paid on the execution of this Agreement (the "**Original Connection Cost Deposit**") by the difference between the Original Connection Cost Deposit and the Total Estimated Allocated Cost of Connection set out in Section 1.1 of the new Schedule "C" plus applicable Taxes on such difference. Should the Customer fail to pay same prior to the expiry of the 20-Day Period:

(i) this Agreement will be deemed to be terminated and the parties shall be under no legal obligation or have any liability of any nature whatsoever with respect to the matters described herein;

(ii) Hydro One will remove the Generator's capacity allocation;

(iii) the Generator's Capacity Allocation Deposit and/or any Additional Capacity Allocation Deposit paid pursuant to the terms of this Agreement will be forfeited by the Generator and will be retained by Hydro One in a deferral account for disposition by the OEB; and

(iv) the Original Connection Cost Deposit less the Actual Cost of the TX Estimate Study (plus applicable Taxes) will be returned to the Generator .

For greater certainty, the Customer acknowledges and agrees that Hydro One will not perform any Hydro One Connection Work until Hydro One has increased the Connection Cost Deposit by the difference between the Original Connection Cost Deposit and the Total Estimated Allocated Cost of Connection set out in Section 1.1 of the new Schedule "C" plus applicable Taxes.

VII. Upstream Transmission Work and Upstream Transmission Rebates

Hydro One's estimate of the Upstream Costs and/or Upstream Transmission Rebates payable by the Generator as set out in Section 1.1. of Schedule "C" of this Agreement, if any, are based on transmission planner estimates as opposed to a Class "C" estimate.

Hydro One's transmission business will perform a Class "C" estimate of the Upstream Transmission Work. If the Class "C" estimate of the cost of the Upstream Transmission Work is greater than the

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Planner's Estimate of the cost of the Upstream Transmission Work, Hydro One shall have the right to require the Generator to increase the Connection Cost Deposit by an amount equal to the difference (plus applicable Taxes). In such an event, Hydro One shall provide the Generator with written notice of same and the Generator shall have 14 days from the date of the notice to increase the Connection Cost Deposit.

Where the Generator is required to pay an Upstream Transmission Rebate and Hydro One's transmission business subsequently performs a Class "C" Estimate of the work previously or currently being performed on Hydro One's transmission system which is the subject of the Upstream Transmission Rebate, Hydro One shall have the right to require the Generator to increase the Connection Cost Deposit by an amount equal to the difference (plus applicable Taxes) between the current estimate of the Upstream Transmission Rebate and the new estimate of the Upstream Transmission Rebate. In such an event, Hydro One shall provide the Generator with written notice of same and the Generator shall have 14 days from the date of the notice to increase the Connection Cost Deposit.

[SIGNATURE PAGE FOLLOWS]

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VIII. This Agreement:

(a) except as expressly provided herein, constitutes the entire agreement between the parties with respect to the subject-matter hereof and supersedes all prior oral or written representations and agreements of any kind whatsoever with respect to the subject matter hereof;

(b) shall be governed by the laws of the Province of Ontario and the federal laws of Canada applicable therein; and

(c) may be executed in counterparts, including facsimile counterparts, each of which shall be deemed an original, but all of which shall together constitute one and the same agreement.

IN WITNESS WHEREOF, Hydro One and the Generator have executed this Agreement in duplicate, as of Execution Date written below.

HYDRO ONE NETWORKS INC.

Name: Myles D'Arcey
Title: Senior Vice President – Customer Operations
Execution Date:
I have the authority to bind the Corporation.

TROUT CREEK WIND POWER INC.

Name:
Title:

Name:
Title:
Date:
I/We have the authority to bind the Corporation

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Schedule "A": Scope of Work

Part A: Hydro One Connection Work

Hydro One will provide project management, engineering, equipment and materials, construction, commissioning and energization for all work required to be performed in respect of Hydro One's distribution system and transmission system in order to Connect the Generation Facility at the PCC.

This specification roughly describes the line and station works that Hydro One will provide to Connect the Generation Facility to Hydro One's distribution system. This specification is based on the "high-level" results from the Impact Assessment and may change materially which may have a material impact on the In-service Date and/or the Allocated Cost of Connection. Exceptions to the specifications are identified within each sub-project plan. All materials and equipment removed will be scrapped at site unless specifically stated otherwise.

CONNECTION ASSETS:

Part 1a: 44 kV Line Connection

Hydro One will:

- Commissioning, customer verification process, and COVER work including, but not limited to, document reviews and acceptance, design reviews and acceptance, and, review and acceptance of COVER.
- For Generation Facilities that lie along the existing distribution system, distribution line work required to connect the proposed Generation Facility tap line to the 44 kV, M7 feeder at the PCC (i.e. line tap connection).
- Set up a pending account in CSS for the Generator
- Provide the following services with respect to the revenue metering:
    - Review and approve revenue metering single line diagram as supplied by the Generator
    - Provide Hydro One's retail metering standard for revenue metering to the Generator
    - Supply and install the required revenue meter(s) at the Generator's cost
- Verify that the installed revenue metering system complies with Hydro One requirements and verify accurate operation
- Integrate meter point into Hydro One power quality (PQ) monitoring system, including, but not limited to, set up in PQ View and set up on web interface.

Assumptions:

- The proposed tap line of 2.25 km 336AL will be built and owned by the Generator.

Part 1b: Where Generator's Facilities do not meet the power distance test (CIA results) AND Generator to install dynamic compensation equipment

Intentionally Deleted.

EXPANSION:

Hydro One will:

- Upgrade 15 km of 3/0 ACSR conductor located upstream of the PCC to 556 AL;

RENEWABLE ENABLING IMPROVEMENTS:

Hydro One will:

- Check the voltage regulating controller at Trout Creek RS line voltage regulator and ensure it is compatible with reverse power flow.
- Trout Creek RS line voltage regulator is required to be operated in Neutral/Idle control mode. Existing controls need to be upgraded such that the regulator must be held in neutral position under reverse real power flow (MW only) condition.
- Check Hydro One distribution system protection coordination and settings including High Voltage (HV) side of the Generation Facility

UPSTREAM TRANSMISSION WORK:

The following work is to be performed on Hydro One's transmission system to address the impact on Hydro One's transmission system of the Connection of the Generation Facility:

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- Install transfer trip between feeder breaker M7 and the Generation Facility and check if Freewave radio is an option for this site. If not, the standard NSD570 equipment will be used. This is the work at Hydro One's end only, and it excludes telecom circuit leasing and work at Generator's end.
    - Distributed Generator End Open (DGEO) signal is required for the Auto-reclose Supervision of the 44 kV, M7 feeder breaker in Trout Lake TS.
    - The feeder breaker must be capable of sending Transfer Trip and receiving DGEO signals.
    - Use Low Set Block Signal (LSBS) from the Generation Facility to the feeder breaker M7 to avoid nuisance tripping due to Generation Facility's interface transformer magnetizing in-rush current.
- Ensure phase and ground fault protection for M7 breaker is directional to avoid nuisance tripping due to adjacent feeder faults.
- Metering devices for M7 feeder need to be compatible with reverse flow. Change if required since reverse power flow will occur on this feeder.
- Monitoring requirement details as per the TIR.

PART B: UPSTREAM HOST DISTRIBUTOR WORK

Nil

PART C: CHANGES TO SCOPE OF WORK

Any change in the scope of the Hydro One Connection Work as described in this Agreement whether they are initiated by the Generator or are Non-Customer Initiated Scope Changes, may result in a change to the Estimated Allocated Cost of Connection and the schedule, including the In-service Date.

All scope changes initiated by the Generator must be made in writing to Hydro One. Hydro One will advise the Generator of any cost and schedule impacts of the scope changes initiated by the Generator. Hydro One will advise the Generator of any material cost and/or material schedule impacts of any Material Non-Customer Initiated Scope Changes.

Hydro One will not implement any scope changes initiated by the Generator until written approval has been received from the Generator accepting the new pricing and schedule impact.

Hydro One will implement all Non-Customer Initiated Scope Change(s) until the estimate of the cost of the Non-Customer Initiated Scope Change(s) made by Hydro One reaches 10% of the total Estimated Allocated Cost of Connection. At that point, no further Non-Customer Initiated Scope Change(s) may be made by Hydro One without the written consent of the Customer accepting new pricing and schedule impact. If the Customer does not accept the new pricing and schedule impact, Hydro One will not be responsible for any delay in the In-service Date as a consequence thereof.

Note:

Portions of the work described in Part A and Part B above may not be performed by Hydro One or the Host Distributor, as the case may be, until after the Generation Facility has been connected to Hydro One's distribution system, including, but not limited to all or portions of the Upstream Transmission Work, de-mobilization work, changes to Hydro One's or the LDC's documentation for their respective facilities, Field Mark prints (FMP) etc.

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Schedule "B": Generator Connection Work

Part 1: General Project Requirements:

The Generator shall:

(a) enter into a Connection Agreement with Hydro One at least 30 days prior to the first Connection to Hydro One's distribution system;

(b) ensure that project data is made available or provided to Hydro One as required by Hydro One;

(c) ensure that the work performed by the Generator and others required for successful installation, testing and commissioning of protective and metering equipment is completed as required to enable Hydro One witnessing and testing to confirm satisfactory performance of such systems;

(d) obtain a certificate of inspection or other applicable approval to be issued or given by the Electrical Safety Authority in relation to the Generator's Facilities;

(e) provide a dedicated dial-up business telephone circuit for the metering equipment in accordance with Hydro One requirements;

(f) provide telephone communication between Hydro One's operator and the Generator's Operator;

(g) make any changes to the Generator's Facilities required for compliance with the *Electrical Safety Code*;

(h) complete its engineering design and provide Hydro One with detailed electrical drawings at least six (6) months prior to the In-service Date mutually agreed by the parties or as reasonably required by Hydro One; and

(i) Provide a COVER that is signed by a Professional Engineer registered in Ontario.

(j) Ensure that Generating Facilities are in compliance with the CIA.

Items (d), (e), and (f) of Part 1 above shall survive the termination of this Agreement.

Part 2: Line tap and Grounding Related Issues

The Generator shall furnish and install a disconnection switch at the PCC for the Generation Facility that opens, with a visual break, all ungrounded poles of the connection circuit. The disconnection switch at the PCC shall be rated for the voltage and fault current requirements of the Facility, and shall meet all applicable CSA standards, ESA requirements, and all other Applicable Laws. The switch enclosure, if applicable, shall be properly grounded. The disconnection switch at the PCC shall be accessible at all times, located for ease of access to Hydro One's personnel, and shall be capable of being locked in the open position.

Part 3: Teleprotection at the Generator's Facilities

The Generator will:

- Provide Low Set Block Signal (LSBS) to mitigate inadvertent trips.
- Accept Transfer Trip Signals from Hydro One M7 feeder breaker.
- Provide Distributed Generator End Open Signal to the Hydro One M7 feeder breaker.
- Provide monitoring requirement details as per the TIR.

Part 3 shall survive the termination of this Agreement.

Part 4: Telecommunications

Prior to the Connection of the Generator's Facilities, the Generator will:

- Provide communications cable entrance facility and cable protection at the Generator's Facilities for telephone circuit for metering and any transfer trip or breaker status if required.
- Be responsible for all monthly leasing costs, and, if required in the future, be responsible for the yearly leasing charge (per pair) for Hydro One's neutralizing transformer capacity. This requirement will be a term in the Connection Agreement.
- Provide circuit routing.

Part 4 shall survive the termination of this Agreement.

Part 5: Work Eligible for Alternative Bid

Not Applicable

Part 6: Revenue Metering

Prior to connection of the Generator's Facilities to Hydro One's distribution system to take or deliver any power, the Generator will be responsible for all costs for Hydro One to supply and install a four quadrant interval metering facility in accordance with, but not limited to, the requirements of Distribution System Code, Measurement Canada, Retail Settlement Code and Hydro One. The Generator may make other arrangements for the metering facility installation that are acceptable to Hydro One and must submit the drawings and specifications for Hydro One's review to determine if the metering location, design and any applicable loss calculations are acceptable to Hydro One. Hydro One will own and maintain the interval metering facility and dedicated dial-up business telephone circuit, if such circuit is required.

Prior to connection of the Generator's Facilities to Hydro One's distribution system to take or deliver any power, the Generator will provide to Hydro One the necessary information so that Hydro One may arrange for registration of the meter point with IESO, if applicable, and arrange for totalization table and settlement systems updates.

Prior to connection of the Generator's Facilities to Hydro One's distribution system to take or deliver any power, if the Generator is a primary metered generator, the Generator shall procure new high accuracy current transformers that meet ANSI 0.15s (the "CTs"). The Generator shall also ensure that the CTs have manufacturer warrantees for a period of at least two (2) years with such warrantees being transferable to Hydro One. The Generator shall be deemed to have transferred the CTs to Hydro One for $1.00 immediately prior to the Generator signing the Connection Agreement.

Part 7: Where Generator's Facilities do not meet the power distance test (CIA results) AND Generator to install dynamic compensation equipment

Intentionally Deleted.

Part 8: Documentation

Prior to Connection of the Generator's Facilities to Hydro One's distribution system, the Generator shall have provided Hydro One with the Connection interface documents specified below for review by Hydro One in the implementation Connection phase.

Connection of a Generation Facility to Hydro One's Distribution System

LIST OF REQUIRED DOCUMENTS

NOTE: Information required for the Design Review must be received AT LEAST 3 months prior to Connection.

Version: Rev 3

	Doc.	Remarks	Timelines	Due Date (Project Specific, based on ISD)
1. Initial Documents	**1. Single Line Diagram** **2. Protection Description Doc. & Power Factor Control** **3. SCADA Communication / Telemetry Points** **4. Power Factor Control of Generator**	**1. The SLD must be acceptable as per the TIR containing all devices clearly identified with the type and brief specifications; including but not limited to:** a) Clear mention / identification of the PCC b) Circuit Breakers c) Transformers d) Disconnecting Switch e) PTs f) Fuses g) Protections h) Teleprotection i) How and where Transfer Trip and DGEO are integrated in and means of communication. j) Status devices k) Device Nomenclature assigned L) Others **2. The Protection Description**	**Required 6 months before ISD in DRAFT,** **4 months before ISD: FINAL approved version.**	

		Doc. must also be acceptable as per the TIR: including but not limited to: **a) Introduction** i) System Description **b) Protection Description** i) Communication ii) Transfer Trip Protection and means i.e. FreeWave Radio, NSD570 / Bell S4T4 iii) Feeder Protection iv) Embedded Generator End Open v) Generation Rejection (G/R) vi) Circuit Switcher Failure vii) Switching Station & Cables Protection viii) Pad Mount Transformer Protection ix) Interlocks x) Circuit switcher Auto-Recloser xi) Ground fault suppression at PCC xii) Generators xiii) Generator Protection ix) Synchronizing of Generator: • Description of Synchronizing Scheme (Synchronous & Inverter Units) & Connection Scheme for Induction Units **c) General Operating Philosophy** **d) Tripping Matrix** / Relay Logic Diagrams **3. SCADA Communication link /Telemetry Pts.:** **The SLD Doc. must also contain:** **a)** SCADA / Telemetry Points, I/O List **b)** Device and Mode of communication / means of access i.e. RTU for SCADA points / Telemetry Path (either Cellular / wireless or Bell S4T4, Fibre) **4. Power Factor Control of Generator** i) Protection AC and DC EWD ii) Protection Three Line Diagrams iii) Interface Protection Relay / Fuse Co-		

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		ordination Study, Curves & Settings iv) Interface Electrical Equipment Technical Information / Data Sheets / Manufacturer's Nameplate Information v) Breaker Failure Protection AC and DC EWD vi) Detailed Power Factor Control Plan		
2. Interface Protection Settings	**Proposed Interface Protection Settings**	Draft Settings	**2 Months before ISD**	
		Final Settings	**2 Weeks before ISD**	
3. Metering	**Metering**	Following must be provided by the Generator if they make other arrangements acceptable to Hydro One to supply and install the metering facility. Revenue Metering Single Line 1) Meter Form, MV 90 2) Site Specific Loss Adjustment (SSLA):(Line and Transformer, as per Market Manual 3-3.5, stamped by an Electrical Engineer Registered in Ontario, Note: Revenue metering single line diagram to use the format and provide the information as per IESO Market Manual 3: Metering, Part 3.6 conceptual Drawing Review. Show ownership boundaries, transformers, CTs, VTs, isolating device / disconnect, breakers, operating designations, etc.	**Required 3 months before ISD**	
4. GPR Study	**Ground Potential Rise (GPR) Study**		**Hydro One may require GPR study results**	
5. SCADA Comm.	**SCADA Communication link / Telemetry Points:**	Order Modem & provide ESN No.	**3 Months before ISD**	
		Activate Modem & Communication link testing	**6 Weeks before ISD**	
		Verification of End to End Testing / SCADA points testing	**2 weeks before ISD**	
6. COVER Doc.	**Commissioning & Verification Procedure, Plan & Schedule Discussion / Meeting**	Formal Discussion / Meeting with Hydro One regarding Commissioning Plan, Procedures and Schedule	**3 months before ISD**	
	COVER Stage 1 – DRAFT/PLAN COVER		**Required 2 months before ISD** (Back Feed or Generation)	

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	COVER Stage 2 – FINAL COVER (Pre-Energization)		2 weeks before ISD	
	COVER Stage 3 – FINAL COVER (Post-Energization)		Required within 5 business days after ISD	
7.	DCA		Draft DCA: 3 months before ISD (Either Back Feed or Generation)	
			Final Signed: 1 month before ISD	
8.	Generator License		Confirmation of Generator License required 2 weeks before ISD	
9.	ESA Certification		2 Weeks before ISD (Either Back Feed or Generation)	

Note:

1. Any delay in submission of each doc. as above will cause delay in the negotiated ISD depending upon the doc., significance and prevailing situations and circumstances
2. Each additional review / resubmission of above documents will lead to additional costs to the project / proponent
3. The requirement of documents and timelines as above are subject to change as per policies, codes and practices time to time but due notice will be given to the proponents
4. The above list includes drawings that would generally be required for Generation Facility projects.
5. Additional drawings / information may be required for certain projects. In such cases, Hydro One will duly inform the Generation Facility.
6. For small generation facility projects, some drawings / information may not be required. For example, those relating to tele-protection, breaker failure, etc.
7. Hydro One's review of Generation Facility drawing / data / protection settings & witnessing of commissioning tests etc. shall be limited only to those portions of the Generation Facility that interests Hydro One and which interfaces with its distribution system.
8. The Generator shall be responsible to coordinate the design, installation, testing, operation and maintenance of its facilities in conformance with applicable codes, standards, Hydro One and IESO connection requirements, service performance requirements and all relevant laws and regulations. The Generator shall obtain, at its expense, any and all authorizations, permits and licenses required for the construction and operation of its Generation Facilities.

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Schedule "C": Estimated Allocated Cost of Connection and Miscellaneous

PART 1:

1.1 Total Estimated Allocated Cost of Connection

The total estimated allocated cost of connection (excluding applicable Taxes) is summarized as follows:

Connection Assets:	$63,000.00
Expansion:	$3,145,000.00
Renewable Enabling Improvements:	$28,000.00
Upstream Costs:[1]	$624,000.00
Upstream Transmission Rebates:	$0
Total Estimated Allocated Cost of Connection	**$3,860,000.00**

The total estimated allocated cost of connection (excluding applicable Taxes) is based on the Class "C" Estimate. Notwithstanding the provision of such Class "C" Estimate to the Generator, the final allocation to the Generator of the cost of connection will be based on the Actual Cost of the Hydro One Connection Work.

1.2 Contingencies:

The above-estimate does not include contingencies that may be necessary in order to Connect the Generation Facility to Hydro One's distribution system. These contingencies include, but are not limited to:

i. Generator initiated scope changes;
ii. Changes to the scope of any Required Connection Work;
iii. planned outage delays/cancellations; subsequent line/equipment commissioning; and
iv. removal and treatment of contaminated soil during excavation.

1.3 Deposits due on execution of Agreement by Generator:

Connection Cost Deposit: $2,843,392.00
Expansion Deposit: $167,736.00
Capacity Allocation Deposit: $0 where the Generator has an executed OPA contract which includes a requirement for security deposits or similar payments

PART 2: MISCELLANEOUS

2.1 Description of Generation Facility

Consists of 4 x 2.5 MW Wind Generation and is located at Lot 17, 18 and 19, Concession 14 in Township of Laurier, District Parry Sound.

2.2 Point of Common Coupling/PCC/Point of Supply:

The Generation Facility will be connected to the 44 kV M7 Hydro One distribution feeder of Trout Lake Transmission Station.

2.3 In-service Date

To be mutually agreed by no later than 45 days after the latest of the date that:

(a) Hydro One has accepted and executed the agreement which occurs after the Generator has delivered and executed this Agreement to Hydro One; and
(b) the Generator paid Hydro One the Deposits specified above in Section 1.3 of this Schedule "C".

[1] Includes the cost of any Upstream Transmission Work and/or Upstream Host Distributor Work.

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In any event, the In-service Date shall not be later than:

(i) five (5) years from the Application date specified in section 2.4 below for water power projects; or
(ii) three (3) years from the Application date specified in section 2.4 below for other types of projects.

2.4 Application Date

July 13, 2010

2.5 Hydro One's Assets:

A. Hydro One will own all equipment and facilities installed by Hydro One as part of the Hydro One Connection Work in, under, on, over, along, upon, through and crossing Hydro One's Property(ies).

B. Hydro One will own the following equipment installed by the Generator in, under, on, over, along, upon, through and crossing Hydro One's Property(ies):
1) Nil

C. Hydro One will own the following equipment installed by Hydro One as part of the Hydro One Connection Work in, under, on, over, along, upon, through and crossing the Generator's Property:

1) Nil

D. Hydro One will own the following equipment installed by the Generator in, under, on, over, along, upon, through and crossing the Generator's Property(ies):

1) High accuracy current transformers that meet ANSI 0.15s.

E. Where applicable, Hydro One will own any Expansion including, any Work Eligible for Alternative Bid with the exception of any Expansion made by a Host Hydro One as part of any required Host Hydro One Work.

2.6 Documentation Required:

Documentation describing the as-built electrical information shall include a resubmission of the information listed in Part 6 of Schedule "B" marked "as built" and signed by a Professional Engineer registered in Ontario.

–Schedule "D": Offer to Connect:

May 11, 2011

TROUT CREEK WIND POWER INC.
49 Bathurst Street, Suite 101,
Toronto, Ontario M5V 2P2

Attn: Mr. Thomas Schneider.

Re: "Offer to Connect" Where a Capital Contribution is Required

Dear Mr. Schneider:

This letter will serve as Hydro One Networks Inc.'s (**"Hydro One"**) "Offer to Connect" in respect of the Expansion of Hydro One's distribution system to accommodate the connection of the proposed 44 kV service for Trout Creek Wind Farm located at Lot 17, 18, 19 Con 14, Township of Laurier, Parry Sound District.

All capitalized terms appearing in this "Offer to Connect" without definition shall have the meaning given to those same terms in the Distribution System Code (the **"Code"**) issued by the Ontario Energy Board. The Code is available online at: www.oeb.gov.on.ca.

Description of Expansion:
This connection requires an upgrade of approximately 15 km of 44 kV line of 3/0 ACSR to 556 AL, located upstream of the PCC.

Estimate or Firm Offer:
This offer is an estimate. It is based on a Class C Estimate, which is a rough estimate, of the capital cost of the construction of the Expansion which generally has a degree of accuracy of plus or minus fifty percent. The actual capital contribution will be revised in the future to reflect the actual costs to construct the Expansion (Please see "Capital Contribution" below for further information) using Hydro One's charge for equipment, labour and materials at Hydro One's standard rates plus Hydro One's standard overheads and interest thereon.

Capital Contribution:
You will be required to pay a capital contribution towards the Expansion.
Hydro One estimates that your capital contribution will be $2,843,392.00 plus GST/HST in the amount of $369,641.00 for a total of $3,213,033.00 (the **"Capital Contribution"**). The Capital Contribution was calculated by Hydro One performing a preliminary economic evaluation. The economic evaluation uses a Discounted Cash Flow (**"DCF"**) model. The calculation used to determine the amount of the Capital Contribution including all of the assumptions and inputs used to produce the economic evaluation is attached to this Offer to Connect. Also included in the Capital Contribution is the cost to provide the final design and estimate ($89,000.00 including applicable taxes) which is required to be performed by Hydro One before actual construction of the Expansion can begin.
The Capital Contribution will be included in the Connection Cost Agreement ("CCA") that will be sent to you shortly as part of the estimated allocated cost of connection. As noted above, Hydro One will re-perform the economic evaluation using the actual costs to construct the Expansion to determine your final capital contribution towards the Expansion which will be payable as part of the final cost which Hydro One will allocate to your project in accordance with Section 16 of the CCA.

Renewable Energy Expansion Cost Cap:
If your facility is a Renewable Energy Generation Facility, the Economic Evaluation includes your Renewable Energy Expansion Cost Cap.

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Alternative Bid Work:

This offer to connect includes work for which you are entitled to obtain an alternative bid ("Work Eligible for Alternative Bid"). Please see Hydro One's Conditions of Service Document referenced below for information on obtaining an alternative bid.

A description of the Work Eligible for Alternative Bid and the Work Not Eligible for Alternative Bid as well as Hydro One's Class C estimate of the costs of such work are described below. Once you execute the CCA and pay the deposits required thereunder, Hydro One will perform the final design and estimate which is required to be performed by Hydro One before any actual construction of the Work Not Eligible for Alternative Bid or Work Eligible for Alternative Bid can begin.

	Work Not Eligible for Alternative Bid (Must be performed by Hydro One)	Work Eligible for Alternative Bid (Can be Performed by Hydro One or By Alternative Bid)
Scope of Work/Description:	Hydro One will: • Upgrade 15 km of 3/0 ACSR conductor located upstream of the PCC to 556 AL;	Nil
Labour (including design, engineering and construction)	$1,085,000.00	$0
Materials	$1,350,000.00	$0
Equipment	$270,000.00	$0
Overhead (including Administration)	$440,000.00	$0

If you choose to perform the Work Eligible for Alternative Bid, the estimated allocated cost of connection in the CCA will include the amount of $0 being Hydro One's estimate of the additional costs (including, but not limited to, inspection costs) that will occur as a result.

Expansion Deposit:

You will be required to pay an Expansion Deposit of $167,736.00 upon the execution of the CCA.

We will endeavor to provide a better estimate of the cost of construction of the Expansion within **90 days** from receipt of the amounts payable under the terms of the CCA. The minimum lead time before start of construction (to allow for ordering material, assigning resources, etc.) will be **60 days** from completion of the field design and staking.

Conditions of Service Document:

For a description of Hydro One's operating practices and connection rules, please see Hydro One's Conditions of Service Document which is available on-line at www.HydroOne.com.

Validity Period – Offer to Connect:

This offer to connect is based on your application for connection and is only valid for a period of:

(a) 180 days if your generation facility is <u>not</u> a Capacity Allocation Exempt Small Embedded Generation Facility; or

(b) 60 days if your generation facility is a Capacity Allocation Exempt Small Embedded Generation Facility;

and is subject to the terms and conditions of the CCA.

Sincerely,

HYDRO ONE NETWORKS INC.

____

Name: Myles D'Arcey
Title: Senior Vice President – Customer Operations

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Schedule "E": Allocated Cost of Connection Statement

As set out in Section 16 of the Standard Terms and Conditions, Hydro One will also provide the Generator with the Allocated Cost of Connection Statement in the form below:

Project Investment No.	
Ready for service date	
Project Title	
Project Description	
Labour (including Design, Engineering, Construction and Commissioning	
Material	
Equipment	
Overhead (including Administration and Project Management)	
Total Cost K$	$

Note 1: Estimated costs during project execution issued to the Generator in accordance with Schedules "A" and "C" for Hydro One Connection work associated with the Connection of the Generation Facility.

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Definitions

1. Throughout the Agreement, unless there is something in the subject matter or context inconsistent therewith, the following words shall have the following meanings:

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

"Actual Cost" means Hydro One's charge for equipment, labour and materials at Hydro One's standard rates plus Hydro One's standard overheads and interest thereon.

"Commercial Operation" has the meaning given to it in Section 2.6 (a) of the form of Feed-In-Tariff Contract posted on the Ontario Power Authority's website on September 30, 2009.

"Commercial Operation Date" means the date on which Commercial Operation is first attained.

"Allocated Cost of Connection" means the cost related to the Connection of the Generation Facility to Hydro One's distribution system that Hydro One has allocated to the Generator in accordance with the Code and where applicable, the Transmission System Code, including:

(a) where applicable, a Capital Contribution as determined by performing an Economic Evaluation using the Actual Cost of the Expansion and any costs payable pursuant to Subsection 15(c);
(b) the cost of the work required in respect of the Connection Assets and any Renewable Enabling Improvement(s);
(c) 100% of the Upstream Costs;
(d) where applicable, the Actual Cost of any Additional Work;
(f) the amounts of any rebates made by Hydro One to any initial contributors in respect of an Expansion in accordance with Section 3.2.27A of the Code which exceeds the Generator's Renewable Energy Expansion Cost Cap irrespective of whether such amounts were originally included in the Estimated Allocated Cost of Connection or in the Class "C" Estimate; and
(g) the amounts of any Upstream Transmission Rebates.

"Additional Capacity Allocation Deposit" means an amount representing $20,000.00 per MW of capacity of the Generation Facility.

"Additional Work" means any work beyond the work described in Schedule "A" as a result of any changes in scope caused by or requested by the Generator and any work that is increased beyond the work estimated in Schedule "A" due to any delays or other actions caused by or requested by the Generator.

"Applicable Laws", means any and all applicable laws, including environmental laws, statutes, codes, licensing requirements, treaties, directives, rules, regulations, protocols, policies, by-laws, orders, injunctions, rulings, awards, judgments or decrees or any requirement or decision or agreement with or by any government or government department, commission, board, court authority or agency.

"Application" means the Generator's application for Connection of the Generation Facility to Hydro One's distribution system.

"Application Date" means the date that the Generator submitted its Application to Hydro One and is as specified in Section 2.4 of Schedule "C".

"Bank" means a bank listed in Schedule I or II of the *Bank Act* (Canada).

"Business Day" means a day other than Saturday, Sunday, statutory holiday in Ontario or any other day on which the principal chartered banks located in the City of Toronto, are not open for business during normal banking hours.

"Cancellation/Termination Costs" means the Actual Cost of the Hydro One Connection Work (plus applicable Taxes) and any Upstream Host Distributor Work accrued on and prior to the date that the Connection is cancelled or the Agreement is terminated, including the preliminary design costs and all costs associated with the winding up of the Hydro One Connection Work and any Upstream Host Distributor Work, including, storage costs, facility removal expenses and any environmental remediation costs.

"Capacity Allocation Exempt Small Embedded Generation Facility" has the meaning given to it in the Code.

"Capacity Allocation Deposit" means an amount representing $20,000.00 per MW of capacity of the Generation Facility.

"Capital Contribution" is the amount that Hydro One may charge the Generator in respect of an Expansion to connect the Generation Facility which shall not exceed the Generator's share of the present value of the projected capital costs (including, where applicable, any Transfer Price paid by Hydro One for the Work Eligible for Alternative Bid) and on-going maintenance costs of the Expansion facilities.

"Class C Estimate" means the rough estimate provided to the Generator by Hydro One of the cost of the work described in the high-level results from the Impact Assessment to be performed by Hydro One in order to Connect the Generation Facility which generally has a degree of accuracy of plus or minus fifty percent.

"Code" means the Distribution System Code issued by the OEB on July 14, 2000 as amended or revised from time to time.

"Connection" and "Connect" have the meaning given to the term "Connection" in the Code.

"Connection Agreement" has the meaning given to it in the Code.

"Connection Assets" has the meaning given to it in the Code.

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"Connection Cost Deposit" means 100% of the total Estimated Allocated Cost of Connection as specified in Part I of Schedule "C".

"Connection Materials" means the materials ordered by Hydro One for the purpose of the Connection.

"COVER" stands for Hydro One's "Confirmation of Verification Evidence Report".

"Customer Impact Assessment" means a customer impact assessment performed by Hydro One's transmission business unit in accordance with the requirements of the Transmission System Code.

"Deposits" means collectively, the Capacity Allocation Deposit, the Additional Capacity Allocation Deposit, the Expansion Deposit and the Connection Cost Deposit.

"Distribute" has the meaning given to it in the Code.

"Economic Evaluation" means the analytical tool designed and used by Hydro One using the methodology and inputs described in Appendix "B" of the Code.

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

"Embedded Retail Generator" has the meaning given to it in the Code.

"Emergency" has the meaning given to it in the Code.

"Enabler Facility" has the meaning given to it in the Transmission System Code.

"Enhancement" has the meaning given to it in the Code.

"ESA" means the Electrical Safety Authority.

"Estimated Allocated Cost of Connection" means Hydro One's estimate of the cost related to the Connection of the Generation Facility to Hydro One's distribution system that Hydro One will have to allocate to the Generator in accordance with the Code and where applicable, the Transmission System Code, including:

(a) where applicable, the Capital Contribution as determined by performing an Economic Evaluation using a Class "C" estimate of the Actual Cost of the Expansion and the costs payable pursuant to Subsection 15(c) below;
(b) the cost of the work required in respect of the Connection Assets and any Renewable Enabling Improvement(s);
(c) 100% of the Upstream Costs;
(d) where applicable, the Actual Cost of any Additional Work;
(e) the amounts of any rebates that will have to be made by Hydro One to any initial contributors in respect of an Expansion in accordance with Section 3.2.27A of the Code which exceeds the Generator's Renewable Energy Expansion Cost Cap; and
(f) the amounts of any Upstream Transmission Rebates.

"Expansion" has the meaning given to it in the Code.

"Expansion Deposit" means a deposit requested by Hydro One to be paid by the Generator that covers both the forecast risk (the risk associated with whether any projected revenue for the Expansion will materialize as forecasted) and the asset risk (the risk associated with ensuring that the Work Eligible for Alternative Bid when it is performed by the Generator, is constructed, that it is completed to the proper design and technical standards and specifications, and that the Work Eligible for Alternative Bid operates properly when energized) which shall not exceed:

(a) 100% of the present value of any forecasted revenues where the Generator has to pay a Capital Contribution; and
(b) 100% of the present value of the projected capital costs and on-going maintenance costs of the work that is not eligible for alternative bid and the Work Eligible for Alternative Bid facilities where the Generator does not have to pay a Capital Contribution.

"Force Majeure Event" means any cause, existing or future, which is beyond the reasonable control of, and not a result of the fault or negligence of, the affected party and includes, strikes, lockouts and any other labour disturbances and manufacturer's delays for equipment or materials required for any Required Connection Work.

"Generation Facility" means the generation facility described in Schedule "C".

"Generator Connection Work" means the work to be performed by the Generator, at its sole expense, which is described in Schedule "B" attached to the Agreement as well as the work described in Part III of the Agreement, if any.

"Generator Default" means any of the following:

(a) failure by the Generator to pay any amount due under the Agreement within the time stipulated for payment;
(b) breach by the Generator of any term, condition or covenant of the Agreement;
(c) the making of an order or resolution for the winding up of the Generator or of its operations or the occurrence of any other dissolution or liquidation proceeding instituted by or against the Generator.

"Generator's Facilities" means the Generation Facility and associated Connection devices, protection systems and control systems owned or operated by the Generator.

"Generator's Property(ies)" means any lands owned by the Generator in fee simple or where the Generator now or hereafter has obtained easement rights.

"Good Utility Practice" has the meaning given to it in the Code.

"Host Distributor" has the meaning given to it in the Code.
"Upstream Host Distributor Work" means any work required to be performed by a Host Distributor on its distribution system in order for Hydro One to Connect the Generation

Facility to Hydro One's distribution system, including the work described in Part C of Schedule "A", attached to the Agreement.

"Hydro One Connection Work" means all of the work to be performed by Hydro One that is required to Connect the Generation Facility to Hydro One's distribution system, including the work described in Part A of Schedule "A", attached to the Agreement.

"Hydro One's Property(ies)" means any lands owned by Hydro One in fee simple or where Hydro One now or hereafter has obtained easement rights.

"IESO" means the Independent Electricity System Operator.

"Impact Assessment" means the impact assessment performed by Hydro One for the Project in accordance with Section 6.2.12 or Section 6.2.13 of the Code, as the case may be, prior to the execution of the Agreement and includes any revisions which may be made to that Impact Assessment from time to time thereafter.

"In-service Date" means the date that Hydro One accepts the normal operation of the Generator's Facilities.

"Interest" means interest accrued monthly commencing on the receipt of any cash Deposit at the Prime Business Rate set by the Bank of Canada less 2 percent.

"Large Embedded Generation Facility" has the meaning given to it in the Code.

"Lender" means a bank or other entity whose principal business is that of a financial institution and that is financing or refinancing the Generation Facility.

"Letter of Credit Minimum Requirements" means a letter of credit that meets all of the following minimum requirements:

(a) is in a form that is satisfactory, to Hydro One;
(b) issued by a Bank;
(c) allows for presentment in Toronto, Ontario or presentment using a valid fax number where the Bank does not have a branch in Toronto, Ontario;
(d) have an expiry date that is acceptable to Hydro One;
(e) provide that any notice that the Bank does not wish to extend the letter of credit for any additional period of expiry must be provided, in writing, to Hydro One Networks Inc., 185 Clegg Road, Markham ON L6G 1B7, Attn: Denise Hunt (R32E2), at least sixty (60) days prior to any expiration date;
(f) permits partial drawings and multiple presentations;
(g) provides that drawings will be paid on written demand without the issuing Bank enquiring whether Hydro One has a right as between itself and the Generator to make such demand, and without recognizing any claim of the Generator;
(h) only requirement to be met in order to draw on the letter of credit is that Hydro One present the letter of credit and a certificate stating that the amount demanded is payable to Hydro One by the Generator pursuant to the terms of the Connection Cost Agreement dated *Insert date*, 20__, as it may be amended by the Generator and Hydro One from time to time;
(i) provides that banking charges and commissions associated with the letter of credit are payable by the Generator;
(j) subject to the International Standby Practices "ISP 98" ICC Publication no. 590 ("ISP 98");
(k) provide that notwithstanding ISP 98, in the event that the original of the letter of credit is lost, stolen, mutilated or destroyed, the Bank will agree to replace same upon written notice from Hydro One setting out the circumstances;
(l) provides that matters not expressly covered by ISP 98, will be governed by the laws of the Province of Ontario and the laws of Canada applicable therein;and
(m) any dispute or claim shall be submitted to the exclusive courts within the jurisdiction of the Province of Ontario.

"Market Rules" means the rules made by the IESO under Section 32 of the *Electricity Act, 1998*.

"Meter Service Provider" means a person that provides, installs, commissions, registers, maintains, repairs, replaces, inspects and tests metering installations.

"Material Revision Impact Assessment" means a revision to the Impact Assessment performed by Hydro One as a result of the Generator making material revisions to the design, planned equipment or plans for the Generation Facility after the execution of the Agreement.

"Mid-Sized Embedded Generation Facility" has the meaning given to it in the Code.

"Non-Customer Initiated Scope Change(s)" means one or more changes that are required to be made to the scope of the Hydro One Connection Work as a result of any one or more of the following:

(a) any changes or revisions to the Impact Assessment made after the execution of the Agreement;
(b) any changes or revisions to the Customer Impact Assessment;
(c) any changes or revisions to the System Impact Assessment;
(d) environmental assessment(s);
(e) the requirements set out in an approval received under Section 92 of the *Ontario Energy Board Act;*
(f) any requirements identified by the IESO in respect of any work required to be performed on Hydro One's transmission system in order for Hydro One to Connect the Generation Facility to Hydro One's distribution system;
(g) any changes to any Required Enhancement(s);
(h) any change to any requirements identified by the Host Distributor in respect of the Upstream Host Distributor Work; and
(i) changes made to the TIR.

"Ownership Demarcation Point" has the meaning given to it in the Code.

"Point of Common Coupling" or "PCC" or "Point of Supply" means the point where the Generator's Facilities are to Connect to Hydro One's distribution system and is as specified in Schedule "C" of the Agreement.

"Premium Costs" means those costs incurred by Hydro One in order to maintain or advance the In Service Date, including, additional amounts expended for materials or services due to short time-frame for delivery; and the difference between having Hydro One's employees, agents and contractors perform work on overtime as opposed to during normal business hours.

"Required Enhancement" means collectively, any Enhancement, Renewable Enabling Improvement or any Enabler Facility that needs to be completed and in service in order for Hydro One to Connect the Generation Facility to Hydro One's distribution system irrespective of whether the cost of any of this work is part of the Allocated Cost of Connection.

"Required Connection Work" means collectively, the Hydro One Connection Work, any Required Enhancement and any Upstream Host Distributor Work.

"Renewable Enabling Improvement" has the meaning given to it in the Code and is limited to those items listed in Section 3.3.2 of the Code.

"Renewable Energy Expansion Cost Cap" has the meaning given to it in the Code.

"Renewable Energy Generation Facility" has the meaning given to it in the Act.

"Renewable Energy Source" has the meaning given to it in the Act.

"Small Embedded Generation Facility" has the meaning given to it in the Code.

"Surety Bond Requirements" means a surety bond that meets all of the following minimum requirements:

(a) is in a form that is satisfactory, to Hydro One;
(b) surety must be Canadian;
(c) surety must be financially acceptable to Hydro One must have at, a minimum, a long-term credit rating of "A" from a bond-rating agency acceptable to Hydro One;
(d) has an expiry date that is acceptable to Hydro One;
(e) provides that fees, charges and commissions associated with the surety bond, including drawings therefrom, are payable by the Generator;
(f) permit partial drawings and multiple presentations;
(g) provide that drawings will be paid without the surety enquiring whether Hydro One has a right as between itself and the Generator to make such demand, and without recognizing any claim of the said Generator;
(h) only requirement to be met in order to draw on the surety bond is that Hydro One present a certificate certifying that the amount demanded is payable to Hydro One by the Generator pursuant to the terms of the Connection Cost Agreement dated *insert date*, 20__, as it may be amended by the Generator and Hydro One from time to time;
(i) will be governed by the laws of the Province of Ontario and the laws of Canada applicable therein; and
(j) any dispute or claim shall be submitted to the exclusive courts within the jurisdiction of the Province of Ontario.

"System Impact Assessment" or "SIA" means the system impact assessment performed by the IESO in respect of connections that the IESO's connection assessment and approvals process requires a system impact assessment which includes without limitation, the connection of a Large Embedded Generation Facility.

"Taxes" means all property, municipal, sales, use, value added, goods and services, harmonized and any other non-recoverable taxes and other similar charges (other than taxes imposed upon income, payroll or capital).

"TIR" means Hydro One's Distributed Generation Technical Interconnection Requirements: Interconnections at Voltages 50kV and Below", as amended from time to time, which is available on Hydro One's website.

"Transfer Price" means the lower of the cost to the Generator to construct the Work Eligible for Alternative Bid or the amount set out in the Initial Offer to Connect attached to the Agreement as Schedule "D" for Hydro One to perform the Work Eligible for Alternative Bid.

"Transmission System Code" means the code of standards and requirements issued by the OEB on July 25, 2005, as it may be amended, revised or replaced in whole or in part from time to time.

"Upstream Costs" means the Actual Cost of any Upstream Transmission Work allocated in accordance with the requirements of the *Transmission System Code* and the Actual Cost of any Upstream Host Distributor Work allocated in accordance with the requirements of the *Distribution System Code* .

"Upstream Transmission Rebates" means refunds payable to any initial contributors in respect of work previously or currently being performed on Hydro One's transmission system at the expense of initial contributor(s) where such work benefits future customers that connect to Hydro One's distribution system within five years of the in service date of that work., which may include the Generator. The amount of any Upstream Transmission Rebates payable are determined by Hydro One considering such factors as the relative name-plated capacities of the initial contributor(s) and the future connecting customer(s).

"Upstream Transmission Work" means any work required to be performed on Hydro One's transmission system in order for Hydro One to Connect the Generation Facility to Hydro One's distribution system, including the work described in Part B of Schedule "A", attached to the Agreement.

"Work Eligible for Alternative Bid" means the Expansion work identified in the Initial Offer to Connect attached to the

Agreement as Schedule "D" as work for which the Generator may obtain an alternative bid.

Incorporation of Code and Application of Conditions of Service

2.1 The Code, as it may be amended from time to time, is hereby incorporated in its entirety by reference into, and forms part of, the Agreement. Unless the context otherwise requires, all references to "the Agreement" include a reference to the Code.

2.2 Hydro One hereby agrees to be bound by and at all times to comply with the Code, and the Generator acknowledges and agrees that Hydro One is bound at all times to comply with the Code in addition to complying with the provisions of the Agreement.

2.3 In addition to the Agreement, the relationship between Hydro One and the Generator will be governed by Hydro One's Conditions of Service that are in effect at the relevant time. In the event of a conflict or an inconsistency between a provision of the Agreement and a provision of Hydro One's Conditions of Service, the provision of the Agreement shall govern.

2.4 In the event of a conflict or an inconsistency between a provision of the Code or the Agreement, the provision of the Code shall govern. The fact that a condition, right, obligation or other term appears in the Agreement but not in the Code shall not be interpreted as, or deemed grounds for finding of a conflict or inconsistency.

Hydro One Connection Work

3. Hydro One shall perform the Hydro One Connection Work in a manner consistent with Good Utility Practice, in accordance with the Conditions of Service and the Code, and in compliance with all Applicable Laws.

4. Except as provided herein Hydro One makes no warranties, express or implied, and Hydro One disclaims any warranty implied by law, including implied warranties of merchantability or fitness for a particular purpose and implied warranties of custom or usage with respect to the Hydro One Connection Work, the Upstream Host Distributor Work and any Required Connection Work.

5. The Hydro One Connection Work, any Required Connection Work and Hydro One's rights and requirements in the Agreement are solely for the purpose of Hydro One ensuring that:

(a) the safety, reliability and efficiency of the distribution system and the transmission system are not materially adversely affected by the Connection of the Generation Facility to the distribution system; and

(b) Hydro One's distribution system and transmission system are adequately protected from potential damage or increased operating costs resulting from the Connection of the Generation Facility.

6. Hydro One shall use commercially reasonable efforts to complete the Hydro One Connection Work by the In-service Date as established in accordance with Section 2.3 of Schedule "C" provided that:

(a) the Generator has completed the Generator Connection Work in accordance with the terms and conditions of the Agreement;

(b) the Generator is in compliance with its obligations under the Agreement;

(c) any work required to be performed by third parties has been performed in a timely manner and in a manner to the satisfaction of Hydro One;

(d) Hydro One has received or obtained prior to the dates upon which Hydro One requires any or one or more of the following under Applicable Laws in order to perform all or any part of the Required Connection Work:
   (i) environmental approvals, permits or certificates;
   (ii) land use permits from the Crown; and
   (iii) building permits and site plan approvals;

(e) Hydro One does not have to use its employees, agents and contractors performing any of the Required Connection Work elsewhere on its transmission system or distribution system due to an Emergency or a Force Majeure Event;

(f) where applicable, the Host Distributor is able to complete the Upstream Host Distributor Work by the date agreed by Hydro One and the Host Distributor in the agreement made between Hydro One and the Host Distributor with respect to such work;

(g) there are no delays resulting from Hydro One being unable to obtain materials or equipment required from suppliers in time to meet the project schedule for any portion of the Hydro One Connection Work or any Required Enhancement;

(h) Hydro One is able, using commercially reasonable efforts, to obtain all necessary land rights on commercially reasonable terms prior to the dates upon which Hydro One needs to commence construction of all or any portion of the Required Connection Work;

(i) where applicable, Hydro One has accepted the metering installation, metering location and transformer loss calculation submitted by the Generator's Meter Service Provider;

(j) Hydro One is able to obtain the materials required to perform the Hydro One Connection Work with the expenditure of Premium Costs where required;

(k) the scope of the Hydro One Connection Work, any Required Enhancement or any Upstream Host Distributor Work does not change substantially for any reason after the execution of the Agreement, including, as a result of the requirements of or matters raised in any System Impact Assessment (including any revisions), Customer Impact Assessment (including any revisions thereto) the Impact Assessment (including any revisions such as a Material Revision Impact Assessment);

(l) the Generator has delivered to Hydro One, any applicable written authorization(s) of the Electrical Safety Authority required for Hydro One to make the temporary and any subsequent Connections; and

(m) there are no delays resulting from the non-completion of any work that needs to be performed on Hydro One's distribution system or transmission system (including, but not limited to, work being performed for a third party connecting a generation facility to Hydro One's distribution system or transmission system) for any reason whatsoever where such work needs to be completed in order for Hydro One to connect the Generation Facility.

The Generator acknowledges and agrees that the In-service Date may be materially affected by difficulties faced by Hydro One in obtaining or the inability of Hydro One to obtain all necessary land rights and/or environmental approvals, permits or certificates and where applicable, any approvals required for under Section 92 of the *Act* for any part of the Required Connection Work.

7. Once the Generator informs Hydro One that it has received all necessary approvals, provides Hydro One with a copy of the authorization to Connect from the ESA and enters into a Connection Agreement, Hydro One shall act promptly to Connect the Generation Facility to Hydro One's distribution system. Subject to delays in commissioning and testing of the Generation Facility which are beyond the control of Hydro One, Hydro One shall Connect a Small Embedded Generation Facility within the timelines prescribed in Subsection 6.2.21 of the Code.

8. The Generator acknowledges and agrees that where there is a Material Revision to An Impact Assessment and that Material Revision to An Impact Assessment:

(a) differs in a material respect from the then-current Impact Assessment, that Part V of the Agreement applies; and

(b) even though it does not differ in a material respect from the then-current Impact Assessment, may result in the scope of the Hydro One Connection Work required to be performed on Hydro One's distribution system and/or any work to be performed on Hydro One's transmission system in order for the Generation Facility to Connect to Hydro One's distribution system to change substantially which could affect the In-service Date and/or the Actual Cost of the Hydro One Connection Work actually required to be performed by Hydro One in order for the Generation Facility to Connect to Hydro One's distribution system.

9. Upon completion of the Hydro One Connection Work, Hydro One shall own, operate and maintain all equipment referred to in Part 2.5 of Schedule "C". Where applicable, the Host Distributor will own, operate and maintain all equipment installed or upgraded as part of the Upstream Host Distributor Work.

__Generator's Obligations – Connection__

10. Except as specifically provided herein, the Generator is responsible for obtaining any and all permits, certificates, reviews and approvals required under any Applicable Laws for the construction, Connection and operation of the Generator's Facilities including, the approval(s) of the Electrical Safety Authority. The Generator shall provide copies of such permits, certificates, reviews and approvals to Hydro One upon Hydro One's request.

11. The Generator shall ensure that the Generator's Facilities:

(a) meet all applicable requirements of the ESA;

(b) conform to all applicable industry standards including, those of the Canadian Standards Association ("CSA"), the Institute of Electrical and Electronic Engineers, the American National Standards Institute and the International Electrotechnical Commission;

(c) are installed and constructed in accordance with the Agreement (including the requirements set out in Schedule "B" of the Agreement), Hydro One's Offer to Connect, the requirements of the ESA, all applicable reliability standards and Good Utility Practice;

(d) other than as specifically permitted in Part III of the Agreement, comply with the requirements described in the TIR, including any additions, modifications or changes to the TIR that are made before the In-service Date; and

(e) meet the technical requirements specified in Appendix F.2 of the Code.

12. The Generator acknowledges and agrees that:

(a) it shall install its own meter in accordance with Hydro One's metering requirements preferably at the Point of Supply with adequate time to allow commissioning for the metering prior to energization of the Generation Facility and provide Hydro One with the technical details of the metering installation;

(b) Hydro One has the right to witness the commissioning and testing of the Connection of the Generation Facility to Hydro One's distribution system;

(c) the Generator shall retain the services of a professional engineer(s) appropriately licensed in Ontario to design and commission the electrical and protection facilities that may impact Hydro One's distribution system, Hydro One's transmission system and where applicable, the distribution system of a Host Distributor; and

(d) the Generator's submissions to Hydro One shall be signed and stamped by a professional engineer appropriately licensed in the province of Ontario.

13. The Generator shall provide Hydro One with copies of the "as built" documentation specified in Schedule "B", acceptable to Hydro One, by no later than 30 days after the execution of the Connection Agreement and the Generator shall ensure that Hydro One may retain this information for Hydro One's ongoing planning, system design, and operating review; and, it shall maintain and revise the documentation to reflect changes to the Generator's Facilities and provide copies to Hydro One on demand or as specified in the Connection Agreement.

Access

14.1 The Generator shall permit and, if the land on which the Generation Facility is located is not owned by Generator, cause such landowner to permit, Hydro One's employees and agents to enter the property on which the Generation Facility is located at any reasonable time. Such access shall be provided for the purposes of inspecting and/or testing the Generation Facility as and when permitted by the Agreement, the Code or Hydro One's Conditions of Service or as required to establish work protection, or to perform any of the Hydro One Connection work.

14.2 Notwithstanding subsection 21(a) below, where Hydro One causes damage to the Generator's property as part of this access, Hydro One shall pay to the Generator the Generator's reasonable costs of repairing such property or, if such property cannot be repaired, replacing such property.

14.3 Notwithstanding subsection 21(a) below, if the Generator has been given access to Hydro One's Property(ies), and if the Generator causes damage to Hydro One's Property(ies) as part of that access, the Generator shall pay Hydro One's reasonable costs of repairing such property or, if such property cannot be repaired, replacing such property.

Expansion - Alternative Bid Work Terms and Conditions:

15. Where the Generator has chosen to pursue an alternative bid in respect of an Expansion and uses the services of a qualified contractor for the Work Eligible for Alternative Bid:

(a) the Generator shall:

- (i) complete all of the Work Eligible for Alternative Bid;
- (ii) select and hire the construction;
- (iii) assume full responsibility for the construction of the Work Eligible for Alternative Bid;
- (iv) be responsible for administering the contract including, the acquisition of all required permissions, permits and easements;
- (v) ensure that the Work Eligible for Alternative Bid is performed in accordance with Hydro One's design and technical standards and specifications;

(b) Hydro One shall have inspected and have approved all aspects of the constructed facilities as part of a system commissioning activity prior to the Connection of the Work Eligible for Alternative Bid to Hydro One's existing distribution system;

(c) the Generator shall be responsible for paying the Actual Cost of the following work to be performed by Hydro One:

- (i) the design of the Work Eligible for Alternative Bid;
- (ii) the engineering or installation of facilities required to complete the project;
- (iii) administration of the contract between the Generator and the contractor hired by the Generator if asked to do so by the Generator and Hydro One agrees, in writing, to do so; and
- (iv) inspection or approval of the work performed by the contractor hired by the Generator;

(d) tby no later than fifteen (15) days prior to the date that the assets are to be transferred to Hydro One, the Generator shall provide Hydro One with a breakdown of the cost of the Work Eligible for Alternative Bid in a form acceptable to Hydro One, together with copies of all documents related to the Work Eligible for Alternative Bid including all invoices, purchase orders and fixed price contracts related to the design and construction of the Work Eligible for Alternative Bid and the procurement of equipment.

(e) the Generator shall represent and warrant to Hydro One on the date that the Work Eligible for Alternative Bid is transferred to Hydro One that:

- (i) the Work Eligible for Alternative Bid is free and clear of all mortgages, liens, demands, charges, pledges, adverse claims, rights, title, retention agreements, security interests, or other encumbrances of any nature and kind whatsoever;
- (ii) the Work Eligible for Alternative Bid is free and clear of any work orders, non-compliance orders, deficiency notices or other such notices relative to the Work Eligible for Alternative Bid Assets or any part thereof which have been issued by any regulatory authority, police or fire department, sanitation, environment, labour, health or other governmental authorities or agencies;
- (iii) there are no matters under discussion with any regulatory authority, police or fire department, sanitation, environment, labour, health or other governmental authorities or agencies relating to work orders, non-compliance orders, deficiency notices or other such notices pertaining to all or any part of the Work Eligible for Alternative Bid;
- (iv) the Generator is the sole owner of the Work Eligible for Alternative Bid;
- (v) that the Work Eligible for Alternative Bid has been performed in accordance with Hydro One's design and technical standards and specifications; and
- (vi) all deficiencies identified by Hydro One have been remedied;

(f) the Generator agrees that the representations and warranties in (e) above shall survive the transfer, and the execution and delivery of any easements or other land rights, bills of sale, assignments or other instruments of transfer of title to the Work Eligible for Alternative Bid and the payment of the transfer price; and

(g) the Generator shall execute all documents necessary to evidence the transfer of the Work Eligible for Alternative Bid to Hydro One, including bills of sale or similar documents and legal, binding and registrable easements from all legal and beneficial owners of lands traversed by the Work Eligible for Alternative Bid and/or land use permits for Crown lands traversed by the Work Eligible for Alternative Bid, satisfactory to and in favour of Hydro One; and

(h) the Generator understands and agrees that Hydro One will not assume and shall not be liable or responsible for any and all liabilities, debts or obligations and demands, direct or indirect, absolute or contingent, of the Generator, whether or not related to, attributable to or in any way connected with the Work Eligible for Alternative Bid. The Generator shall pay, satisfy, assume, discharge, observe, perform, fulfil, release, and indemnify and save harmless Hydro One and its successors, its directors, officers, employees, representatives and agents from and against such liabilities, debts and obligations and all costs, expenses, debts, demands, proceedings, suits, actions, losses or claims in connection therewith. This obligation shall survive the termination of the Agreement; and

(i) Hydro One shall pay the Generator the Transfer Price on the transfer date. The Transfer Price shall be considered a cost to Hydro One for the purposes of the final Economic Evaluation to be performed by Hydro One.

Allocated Cost of Connection, Deposits and Cancellation/Termination Costs

16. The Generator shall pay Hydro One the Allocated Cost of Connection. Upon the execution of the Agreement by the Generator, the Generator shall provide Hydro One with:

(a) the Connection Cost Deposit;
(b) the Capacity Allocation Deposit if the Generator does not have an executed OPA contract for the Generation Facility; and
(c) the Expansion Deposit, where applicable,

in the amounts specified in Section 1.3 of Schedule "C" which must be in the form of cash (by way of certified cheque), letter of credit or surety bond. Letters of credit must meet the Letter of Credit Minimum Requirements and surety bonds must meet the Surety Bond Minimum Requirements. Hydro One strongly encourages the Generator to pay the Connection Cost Deposit in cash so as to reduce interest during construction charges.

Where the Connection Cost Deposit is provided in cash, Hydro One shall have the right to use the Connection Cost Deposit as Hydro One incurs costs that are part of the Allocated Cost of Connection. Where the Connection Cost Deposit is provided in any form other than cash, Hydro One may invoice the Generator from time to time for work performed that is part of the Allocated Cost of Connection and should the Generator fail to pay any invoice, Hydro One shall have the right to draw on the letter of credit or surety deposit, as the case may be. If the Generator pays the invoice(s) in full, Hydro One may lower the amount secured by the letter of credit or surety deposit, as the case may be, by an amount not to exceed the amounts of the invoices so paid so long as the letter of credit or surety dpeosit permis Hydro One to do so, from time to time on written notice to the Bank with no penalty, banking charges and commissions being payable by Hydro One.

In the event that Hydro One determines from time to time, acting reasonably, that the Connection Cost Deposit specified in Section 1.3 of Schedule "C" is inadequate based on Hydro One's forecast that the Allocated Cost of Connection will exceed the Estimated Allocated Cost of Connection by 20% or more, Hydro One shall have the right to require the Generator to increase the Connection Cost Deposit from time to time in an amount equal to the forecasted deficiency. In such an event, Hydro One shall provide the Generator with written notice of same and the Generator shall have 14 days from the date of the notice to increase the Connection Cost Deposit. This will also assist in reducing interest during construction charges.

If the Generation Facility is not connected to Hydro One's distribution system fifteen (15) calendar months following the execution of the Agreement and the Generator does not have an executed OPA contract which includes a requirement for security deposits or similar payments, the Generator shall pay Hydro One an Additional Capacity Allocation Deposit by no later than the first day of the sixteenth (16^{th}) calendar month following the execution of the Agreement.

Should a letter of credit or surety bond be set to expire before the Generator has been invoiced for and/or paid the Allocated Cost of Connection, Hydro One shall have the right to draw upon same not earlier than 30 days prior to the expiry of the letter of credit or surety bond and shall treat the amount drawn as a cash deposit.

Hydro One will return any Expansion Deposit in accordance with the requirements of Section 3.2.23 of the Code (and Section 3.2.26 of the Code where the Expansion Deposit is in the form of cash) subject to Hydro One's rights to retain and use the Expansion Deposit in accordance with Sections 3.2.22 and 3.2.24 of the Code. Subject to Part V of the Agreement, Hydro One will return the Capacity Allocation Deposit and any Additional Capacity Allocation Deposit (with interest if any such deposit(s) are in the form of cash) by no later than 30 calendar days following the In-service Date.

Hydro One shall use reasonable commercial efforts to provide the Generator with a final invoice or credit memorandum within 180 days following the later of: (i) the In-Service Date; and (b) the date that Hydro One fully performs all of the Hydro One Connection Work, including, but not limited to those portions of the Hydro One Connection Work that may be completed following the In-Service Date. The final invoice or credit memorandum shall indicate whether the Connection Cost Deposit exceeds or is less than Allocated Cost of Connection (plus applicable Taxes). Any difference shall be paid within 30 days after the rendering of the said final invoice or credit memorandum by Hydro One to the Generator. If the Connection Cost Deposit exceeds the Allocated Cost of Connection, Hydro One shall pay interest on the amount by which the Connection Cost Deposit exceeded the Allocated Cost of Connection where the Connection Cost Deposit was provided in the form of cash).

In addition to the final invoice or credit memorandum, Hydro One shall also provide the Generator with the Allocated Cost of Connection Statement in the form attached to the Agreement as Schedule "E".

17. Future customers that benefit from any part of the Upstream Transmission Work who connect to Hydro One's distribution system within five years of the in service date of that part of the Upstream Transmission Work will be required to pay an Upstream Transmission Rebate. Any Upstream Transmission Rebate collected by Hydro One in respect of any part of the Upstream Transmission Work will be paid to the Generator as a refund following the connection of any such future customer(s). The Generator acknowledges and agrees that should any such future customer(s) challenge the requirement to pay an Upstream Transmission Rebate and should the OEB agree that such future customer(s) should not have had to make such payment, that the Generator will refund to Hydro One any Upstream Transmission Rebate(s) that the Generator received from Hydro One. THIS OBLIGATION SHALL SURVIVE THE TERMINATION OF THE AGREEMENT.

18. Hydro One shall refund to the Generator or the Generator shall pay to Hydro One any amount, which the OEB subsequently determines should not have been allocated to the Generator or should have been allocated to the Generator by Hydro One but were not, as the case may be, or should have been allocated in a manner different from that allocated by Hydro One in the Agreement.

19. Hydro One will obtain the Generator's approval prior to Hydro One authorizing the purchase of materials or the performance of work that will attract Premium Costs if the total of the Premium Costs exceed $10,000.00. Premium Costs are in addition to the costs payable by the Generator pursuant to Section 16 hereof. The Generator acknowledges that its failure to approve an expenditure of Premium Costs may result in further delays and Hydro One will not be liable to the Generator as a result thereof. The Generator shall pay any prior-approved Premium Costs within 30 days after the date of Hydro One's Invoice.

20. If the Connection is cancelled, or the Agreement is terminated for any reason whatsoever other than breach of the Agreement by Hydro One, the Generator shall pay the Cancellation/Termination Costs. Hydro One will apply the Connection Cost Deposit and where applicable, the Expansion Deposit, against the Cancellation/ Termination Costs. In the event that the Connection Cost Deposit and where applicable, the Expansion Deposit:

(a) exceeds the Cancellation/Termination Costs, the unspent Connection Cost Deposit and where applicable, the Expansion Deposit will be returned to the Generator by no later than 180 days after the date that the Connection is cancelled or the Agreement is terminated; and

(b) is less than Cancellation/Termination Costs, the Generator shall pay Hydro One the difference within 30 days after the date of Hydro One's invoice.

21. In the event that the Generator sells, leases or otherwise transfers or disposes of all or part of the Generator's Facilities to a third party during the term of the Agreement, the Generator shall cause the purchaser, lessee or other third party to whom the Generator's Facilities are transferred or disposed to enter into an assumption agreement with Hydro One to assume all of the Generator's rights and obligations in the Agreement; and notwithstanding such assumption agreement, the Generator shall remain obligated to pay the amounts thereafter payable pursuant to Sections 16, 17, 18, 19 and 20 hereof by the purchaser, lessee or other third party in the case of a transfer or disposition.

Liability and Force Majeure

22.(a) The liability provisions of section 2.2 of the Code apply to the Agreement and are hereby incorporated by reference into, and forms part of, the Agreement *mutatis mutandis*.

(b) The parties agree that the aggregate liability of Hydro One under the Agreement and in particular under Subsection 21(a) above, shall at no time exceed the Allocated Cost of Connection.

(c) A party shall have a duty to mitigate any losses relating to any claim for indemnification from the other party that may be made in relation to that other party. Nothing in this section shall require the mitigating party to mitigate or alleviate the effects of any strike, lockout, restrictive work practice or other labour dispute.

(d) A party shall give prompt notice to the other party of any claim with respect to which indemnification is being or may be sought under the Agreement.

23. The liability provisions set out in Section 21 above shall not apply to damages to Hydro One's distribution system or increased operating costs resulting from the Connection of the Generation Facility to Hydro One's distribution system. The Generator shall reimburse Hydro One for same in accordance with the invoices rendered by Hydro One for same.

24. The force majeure provisions of section 2.3 of the Code apply to the Agreement and are hereby incorporated by reference into, and form part of, the Agreement *mutatis mutandis*.

25. Sections 22, 23 and 24 above shall survive the termination of the Agreement.

Waiver

26. A waiver of any default, breach or non-compliance under the Agreement is not effective unless in writing and

signed by the party to be bound by the waiver. The waiver by a party of any Event of Default, breach or non-compliance under the Agreement shall not operate as a waiver of that party's rights under the Agreement in respect of any continuing or subsequent Event of Default, breach or non-compliance, whether of the same or any other nature.

Amendment

27. Any amendment to the Agreement shall be made in writing and duly executed by both parties.

Exchange and Confidentiality of Information

28. Section 20 of the form of Connection Agreement for a Small Embedded Generation Facility or a Mid-Sized Embedded Generation Facility set out in Appendix E of the Code is hereby incorporated by reference into, and forms part of the Agreement *mutatis mutandis*.

Interpretation

29. Unless otherwise specified, references in the Agreement to Sections or Schedules are to sections, articles and Schedules of the Agreement. Any reference in the Agreement to any statute, regulation, any OEB-approved documents or any section thereof will, unless otherwise expressly stated, be deemed to be a reference to such statute, regulation, document or section as amended, restated or re-enacted from time to time. The insertion of headings is for convenience only, and shall not affect the interpretation of the Agreement. Unless the context requires otherwise, words importing the singular include the plural and vice versa. The words "including" or "includes" means including (or includes) without limitation.

Invoices and Interest

30. Invoiced amounts are due 30 days after invoice issuance. All overdue amounts including amounts that are not invoiced but required under the terms of the Agreement to be paid in a specified time period, shall bear interest at 1.5% per month compounded monthly (19.56 percent per year) for the time they remain unpaid.

Assignment, Successors and Assigns, Lenders

31.(a) Except as set out in Section 31 below, the Generator shall not assign its rights or obligations under the Agreement in whole or in part without the prior written consent of Hydro One, which consent shall not be unreasonably withheld or unduly delayed. Hydro One may withhold its consent to any proposed assignment until the proposed assignee assumes, in writing, all of the Generator's obligations contained in the Agreement.

(b) Hydro One shall have the right to assign the Agreement in whole upon written notification to the Generator.

(c) The Agreement shall be binding upon and enure to the benefit of the parties and their respective successors and permitted assigns.

31(a). The Generator may, without the written consent of Hydro One, assign by way of security only all or any part of its rights or obligations under the Agreement to a Lender(s). The Generator shall promptly notify Hydro One, in writing, upon making such assignment.

(b) The Generator may disclose confidential information of Hydro One to a Lender or prospective Lender provided that the Generator has taken all precautions as may be reasonable and necessary to prevent unauthorized use or disclosure of Hydro One's confidential information by a Lender or prospective Lender.

(c) Where a notice of default has been served on the Generator under Part V of the Agreement, an agent or trustee for and on behalf of the Lender(s) ("**Security Trustee**") or a receiver appointed by the Security Trustee ("**Receiver**") shall upon notice to Hydro One be entitled (but not obligated) to exercise all of the rights and obligations of the Generator under the Agreement and shall be entitled to remedy the default specified in the notice of default within the cure period referred to in Part V. Hydro One shall accept performance of the Generator's obligations under the Agreement by the Security Trustee or Receiver in lieu of the Generator's performance of such obligations.

(d) the Lender will have no obligation or liability under the Agreement by reason of the assignment until such time as the Lender, the Security Trustee or the Receiver exercises any of the rights or obligations of the Generator under the Agreement.

(e) notwithstanding subsection (d) above, Hydro One agrees that the Lender will have no obligation or liability under the Agreement by reason of the assignment if the Lender exercises the obligation of the Generator under the Agreement to cure a default for failing to pay an amount(s) due and owing under the Agreement within the cure period provided for in the Agreement after written notice of such default is delivered to the Generator.

(f) The Generator shall be deemed to hold the provisions of this Section 31 that are for the benefit of Lender(s) in trust for such Lender(s) as third party beneficiary(ies) under the Agreement.

Survival:

32. The obligation to pay any amount due hereunder, including, but not limited to, any amounts due under Sections 16, 17, 18, 19 or 20 shall survive the termination of the Agreement.

The attached is **Exhibit "C"** to the Affidavit of
Thomas Schneider, sworn before me
this 25th day of May, 2011

A Commissioner, etc.

KEVIN FREDRICK WENTZEL, a
Commissioner, etc., Province of Ontario,
while a Student-at-Law.
Expires April 29, 2014.

Kenneth P. Eccleston
Direct Line: 416|504|3364
ken@ecclestonllp.com

* Certified by the Law Society of Upper Canada as a Specialist in Construction Law

VIA COURIER

April 14, 2011

Peter Fraser
Acting Managing Director-Regulatory Policy
Ontario Energy Board
P.O. Box 2319-2300 Yonge Street, 27th Floor,
Toronto, ON
M4P 1E4

Re:	Our client:	Schneider Power Inc.
	Project:	Project 12,780-Trout Creek Wind Farm ("Project")
	Our File No.	2-11-012

We act for Schneider Power Inc. ("Schneider Power") and Trout Creek Wind Power Inc. in connection with matters related to the above noted Project. The proposed Project is to be constructed on Crown lands.

The Project

On April 30, 2010, Trout Creek Wind Power Inc., (the "Supplier") a Project entity which is a wholly owned subsidiary of Schneider Power Inc., entered into a contractual agreement with the Ontario Power Authority ("OPA") to supply electricity on a Commercial Operation Date ("COD") of April 30, 2013. An unforeseeable delay in obtaining Applicant of Record status, which was beyond the control of the Supplier, has prevented the Supplier from commencing necessary studies in support of the application for permits necessary to proceed to the COD.

Actions of MOE and MNR

A delay in the issuance of Applicant of Record status has resulted in the Supplier not being able to submit a proposal for a wind testing facility and associated permit application in a timely manner. This delay has also resulted in the Supplier not being able to commence the REA process in a timely manner. The delay is largely a result of the actions or inactions of the Ministry of Natural Resources ("MNR") and the Ministry of the Environment ("MOE"). The delay has compromised the schedule for Project development to the extent that the Supplier will not be able to meet the milestones and deadlines established in the Feed-In Tariff Contract ("FIT Contract"), all of which was beyond the control of the Supplier.

The MNR provided the Supplier with a "*Windpower Applicant Declaration Form*" on June 10, 2010 after which the Supplier subsequently submitted the completed form to the MNR six days later. Through discussion with the MNR it was agreed that the public notification commencement date would be left blank because the MNR had instructed that the Supplier not issue public notice of the proposal until such time that they had satisfactorily notified and consulted with potentially interested or affected Aboriginal communities.

MNR began to compile a list of Aboriginal communities requiring notification of the proposal prior to the June 7th meeting. The final list, collaboratively developed by the MNR and the MOE, was not finalized until October 6, 2010. Throughout that period, the Supplier elicited regular updates on progress being made toward finalizing the list and continued to work on other aspects of the wind testing proposal and the wind farm proposal.

As a result of these delays and the impact on the Project, on August 19, 2010, Schneider Power requested a meeting with the Renewable Energy Facilitation Office ("REFO") to seek help as the permitting timeline would make meeting the FIT contract deadlines impossible. A "*Renewable Energy Approval Proponent Pre-Submission Consultation Meeting*" request was faxed to the MOE on September 1, 2010. A meeting attended by the Supplier, MNR, MOE and REFO was held September 8, 2010. Several concerns were discussed during this meeting:

- The Supplier needs to begin work on studies related to the REA, especially long lead-time studies such as bird studies; however the MNR would not permit this work as Applicant of Record status had not yet been issued.
- The timeline for submitting the revised wind testing proposal was uncertain as the MNR could not indicate how much time would be required to notify and consult Aboriginal communities.

Timeline Challenges

Schneider Power has not been able to officially launch the REA process because it has not been granted Applicant of Record status. The delay that has been experienced in obtaining Applicant of Record status has compromised the ability of the Project to meet the milestones associated with the FIT contract. According to the terms and conditions of the FIT Contract, Schneider Power has interpreted the key project milestone dates as follows:

Contract Date:	April 30, 2010;
Milestone Date for Commercial Operation:	April 30, 2013
Deadline to submit complete Notice to Proceed ("NTP") Request:	October 30, 2012

It should be noted that these dates under the FIT Contract will likely be extended 16 months as a result of *force majeure* applications to OPA. It is significant to note that OPA have recognized the significance of these delays which are acknowledged to be beyond the control of the Supplier. Therefore, the Supplier expects the new COD will be August 30th, 2014.

Documentation of a complete REA is required as a pre-requisite to submitting a NTP Request. Working back from the NTP Request deadline and factoring in a possible six month Environmental Review Tribunal hearing and six months for the Ministry of the Environment to coordinate the review of the REA and issue a decision, the REA will need to be submitted by October 2011, at the latest, in order to meet the NTP Request deadline.

Delays caused by regulatory authorities have affected the Project development timeline such that the FIT contract deadlines cannot be met. As of January 31, 2011, the Supplier has only nine months in which to erect a wind testing tower, commence the REA process, and complete an REA submission. Specifically, the delay in obtaining Applicant of Record status has delayed the wind power testing phase of the Project, which is necessary to finalize the turbine locations and properly define the Project Location, which is the starting point of the natural heritage assessment, the cultural heritage assessment, and integral to the drafting of the Project Description Report. The OPA COD required that the Supplier have the all approvals for the wind power testing tower issued by end of 2010 and the tower installed and operational by early spring 2011 at the latest.

Connection Cost Deposit

Pursuant to the requirements of the Distribution System Code and the Connection Cost Estimate Agreement, the Supplier is being required to make full payment of the Connection Cost Deposit ("CCD") now. Under normal circumstances the Supplier would expect to pay the HONI CCD in part lots beginning approximately 1 year prior to construction. One year prior to the expected revised COD will be August 30th, 2013, or 28 months from now. The idea of fully prepaying a 2.9 million '*estimate*', plus the HST due on that estimate, over three years before COD is not sound business practice and places significant financial burdens on the Supplier.

Project Expenditures to Date

The total Project cost expenditures to date total the sum of $314,820 which is detailed in the attachment. In addition to these expenditures the following prepaid deposits have been made in connection with the Project, $209,000.00 (comprised of $100,000.00 to the OPA; $100,000.00 under the terms of the FIT Contract and $5,000.00 to HONI under the Connection Cost Estimate Agreement and $4,000.00 to MacLeod).

Project Viability and Projected Timelines

In considering an extension to the CCD requirement, it is important to consider the Project viability and what might be accomplished with an extension. It is reasonable to expect to have the following completed in the next 12-18 months:

- Secure land use permit and work permit for installation and operation of the meteorological tower. 12 MONTHS
- Complete the requisite 1 year of audited wind data. 16 MONTHS

- Initiate and progress through the Renewable Energy Approval (REA) process.
  - Hold first of two required public meetings 12 MONTHS
  - Submit natural heritage assessment to Ministry of Natural Resources for review 18 MONTHS
  - Submit heritage assessment to Ministry of Culture for review 18 MONTHS
  - Finalize draft submission documents and be in a position to plan for final public meeting and application submission 18 MONTHS
- Initiate and progress through the Class EA process for the access road (coordinated with REA process). 12 MONTHS

Force Majeure

Each of the Distribution System Code (Article 2.3), the Connection Cost Estimate Agreement (Articles 25 through 28) entered into with Hydro One Networks Inc. ("HONI") and the Feed-In Tariff Agreement (Article 10) with OPA provide for relief arising from *force majeure*. By definition *force majeure* events constitute events beyond the control of the parties which restrict participants from fulfilling obligations. In each of the three agreements strict performance of obligations is excused in the event a *force majeure* event '*....prevents a party from performing any of its obligations under this Code and the applicable Connection Agreement.*' (Article 2.3.2 Distribution System Code).

Therefore the Supplier and Schneider Power seek an extension to the requirement to make full payment of the Connection Cost Deposit under the force majeure provisions of the Distribution System Code and the Connection Cost Estimate Agreement. The Supplier anticipates that an 18 month extension would be required to compensate for the delays experienced to date.

Should you wish to discuss the matter, please feel free to contact me.

Yours very truly,

Kenneth P. Eccleston

Encl:

The attached is **Exhibit "D"** to the Affidavit of
Thomas Schneider, sworn before me
this 25th day of May, 2011

A Commissioner, etc.

KEVIN FREDRICK WENTZEL, a
Commissioner, etc., Province of Ontario,
while a Student-at-Law.
Expires April 29, 2014.

Kenneth P. Eccleston
Direct Line: 416|504|3364
ken@ecclestonllp.com

* Certified by the Law Society of Upper Canada as a Specialist in Construction Law

VIA COURIER

May 9, 2011

Peter Fraser
Acting Managing Director-Regulatory Policy
Ontario Energy Board
P.O. Box 2319-2300 Yonge Street, 27th Floor,
Toronto, ON
M4P 1E4

Re: Our client:	Schneider Power Inc.	
Project:	Project 12,780-Trout Creek Wind Farm ("Project")	
Our File No.	2-11-012	

We act for Schneider Power Inc. ("Schneider Power") and Trout Creek Wind Power Inc. in connection with matters related to the above noted Project and this letter is supplementary to our correspondence of April 14, 2011.

Since our letter, I understand that the Ontario Energy Board ("OEB") has created a special exemption for small hydro dam projects which relieves them from paying the full amount of the Hydro One Networks Inc. ("HONI") Connection Cost Deposit ("CCD") upfront, instead allowing developers to pay a $20,000 deposit on the CCD with stepped milestone payments thereafter.

In an oral decision made on May 5, 2011 the OEB granted an application by Ontario Waterpower Association ("OWA") for an exemption from sections 6.2.4.1(e) and 6.2.18 of the Distribution System Code ("DSC") for waterpower hydroelectric projects with a nameplate capacity of between 1 and 10 MW that are located on provincial Crown or federally-regulated lands. The Trout Creek Wind Farm Project is a 10MW project located on Crown lands, although a windpower project.

Section 6.2.4.1(e) of the DSC requires a distributor (in this case Hydro One) to remove an applicant's connection capacity allocation if the applicant has not signed a connection cost agreement (CCA) within 6 months of receiving the allocation. The provision was introduced in the fall of 2009 to ensure that connection capacity was not tied up by projects that were not being pursued diligently. The Board found there was no evidence that the 28 hydroelectric projects at issue in the application were "laggards" and noted that such projects face unique challenges because of their site-specific nature and the extensive approval processes involved, similar to those faced with the Trout Creek Wind Farm Project.

Accordingly, the Board granted these waterpower projects an indefinite exemption to this requirement. Section 6.2.18 of the DSC requires an applicant to pay a connection cost deposit equal to 100% of the total estimated allocated cost of connection when the CCA is signed. Again the purpose of the provision is to ensure that connection capacity is not tied up by projects that are not being pursued diligently. The evidence before the Board established that it was difficult for waterpower proponents to obtain sufficient financing to meet this requirement at the CCA stage given the extensive regulatory processes that still need to be completed. In place of section 6.2.18, the Board accepted a schedule under which an applicant will pay an initial deposit of $20,000 with increased amounts due as various steps in the development process are achieved.

This decision provides relief to project developers who couldn't raise capital to pay the full CCD amount during the pre-construction phase. While the decision is a welcome admission of a flawed payment structure, it is arbitrarily applied to 1-10MW waterpower projects only. The Trout Creek Wind Farm Project falls into the same category as the projects affected by this decision, with the exception that it is a windpower project. It seems increasingly inequitable that an extension to the requirement to make full payment of the Connection Cost Deposit should not be granted.

Once OEB have had an opportunity to consider this matter we would very much appreciate a response to our letters in this matter.

Yours very truly,

Kenneth P. Eccleston

Encl:

The attached is **Exhibit "E"** to the Affidavit of
Thomas Schneider, sworn before me
this 25th day of May, 2011

A Commissioner, etc.

KEVIN FREDRICK WENTZEL, a
Commissioner, etc., Province of Ontario,
while a Student-at-Law.
Expires April 29, 2014.

Ontario Energy Board
P.O. Box 2319
26th. Floor
2300 Yonge Street
Toronto ON M4P 1E4
Telephone: 416-481-1967
Facsimile: 416-440-7656
Toll free: 1-888-632-6273

Commission de l'Énergie
de l'Ontario
C.P. 2319
26e étage
2300, rue Yonge
Toronto ON M4P 1E4
Téléphone: 416-481-1967
Télécopieur: 416-440-7656
Numéro sans frais: 1-888-632-6273

Ontario

BY EMAIL ONLY

May 13, 2011

Mr. Kenneth P. Eccleston
Eccleston LLP Barristers and Solicitors
66 Wellington Street West
Suite 3820, Toronto Dominion Bank Tower
P.O. Box 230, Toronto Dominion Centre
Toronto ON M5K 1J3

Dear Mr. Eccleston:

Re: Schneider Power Inc.
Project 12,780-Trout Creek Wind Farm
Request for Relief from Section 6.2.18 of the Distribution System Code

Board staff is in receipt of your letter in respect of the Trout Creek Wind Farm project, dated May 9, 2011, as well as your original letter dated April 14, 2011. Your letter of May 9, 2011 references a Decision rendered by the Board on May 5, 2011 (EB-2011-0067 – the "OWA proceeding") with respect to certain waterpower projects (the "May 5 Decision"). As you are aware the OWA applied for a licence amendment to Hydro One's licence exempting Hydro One from certain obligations under the Distribution System Code (the "DSC").

Board staff cannot opine on decisions of the Board and the underlying reasons leading to a decision. I note that Schneider Power Inc. was served with notice of the OWA proceeding. Further, in its Decision the Board noted that ""while notice in this proceeding was extremely inclusive, no representatives of other forms of generation or other stakeholders saw fit to oppose this application."

The scope of the May 5 decision was limited to waterpower projects of nameplate capacity of 10 MW or below. In its decision the Board noted that it was "mindful that proponents of hydroelectric projects located on Crown land within the province of Ontario, or federally-regulated lands, experience a unique set of circumstances which can impair their ability to meet some of the obligations created by the DSC and FIT program".

Under the circumstances, it is clear that the relevant DSC requirements (including sections 6.2.4.1(e) and 6.2.18) continue to apply to the Trout Creek Wind Farm.

Yours truly,

Original signed by

Peter Fraser
Acting Managing Director, Regulatory Policy

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The attached is **Exhibit "F"** to the Affidavit of
Thomas Schneider, sworn before me
this 25th day of May, 2011

A Commissioner, etc.

KEVIN FREDRICK WENTZEL, a
Commissioner, etc., Province of Ontario,
while a Student-at-Law.
Expires April 29, 2014.

ONTARIO POWER AUTHORITY

120 Adelaide Street West
Suite 1600
Toronto, Ontario M5H 1T1

T 416-967-7474
F 416-967-1947
www.powerauthority.on.ca

April 18, 2011

Trout Creek Wind Power Inc.
49 Bathurst Street, Suite 101
Toronto
M5V 2P2, ON

Dear **Mr. Schneider**,

Re: Feed-In Tariff Contract No. F-000655-SPV-130-601 between the Ontario Power Authority ("OPA") and Trout Creek Wind Power Inc. (the "Supplier") dated April 30, 2010 (the "FIT Contract") – Force Majeure Claim No. 1 and Force Majeure Claim No. 2

I refer to your Notice of Force Majeure for Force Majeure Claim No. 1 and Notice of Force Majeure for Force Majeure Claim No. 2, dated February 1, 2011 and April 11, 2011 respectively, (collectively, the "**Notices**"), wherein the Supplier submitted Force Majeure claims (the "**FM Claims**") to the OPA, in accordance with section 10.1(b) of the FIT Contract.

All capitalized terms not otherwise defined have the meaning ascribed to them under the FIT Contract.

The OPA has determined that the FM Claims are valid and notes the following:

1. The OPA recognizes that some of the delays experienced by the Supplier in respect of Force Majeure Claim No. 2 constitute a valid FM event in respect of REA delays. The OPA considers that the FM Claim gives rise to a delay of four months.

2. The Milestone Date for Commercial Operation, originally April 30, 2013, is extended for a period of four months to August 30, 2013.

3. The OPA has reviewed Force Majeure Claim No. 1 and has determined that it constitutes a valid FM event, commencing on January 18, 2011 (the "**FM Start Date**"). Further to the Supplier's notice of the termination of the Force Majeure, dated March 28, 2011, the FM terminated on March 17, 2011 and, accordingly, the Supplier is entitled to 58 days of relief as a result of Force Majeure Claim No. 1. Therefore, the revised Milestone Date for Commercial Operation is extended to October 27, 2013.

4. As discussed previously, the OPA is offering the Supplier an extension of the Milestone Date for Commercial Operation by entering into a FIT Amending Agreement Re: Extension of Milestone Date for Commercial Operation for non-CAE Projects (the "**Amending Agreement**"). The above-mentioned extension is granted by the Amending Agreement in exchange for, inter alia, the Supplier agreeing to adhere to Section 6 of the Amending Agreement, which provides for a Moratorium Period for Force Majeure claims, as defined therein.

These extensions remain subject to the terms and conditions of the FIT Contract, including without limitation Articles 9 and 10. The OPA's granting of FM relief under the FIT Contract is made in reliance on the Notice and the representations and warranties below. The remaining terms and conditions of the FIT Contract shall remain unamended and in full force and effect.

By countersigning and returning this letter, the Supplier represents, warrants and agrees to and with the OPA that:

(a) the FM Claims are true, complete and accurate in all material respects and that there is no material information omitted which would make the information contained therein misleading or inaccurate;

(b) the Supplier is not in breach of the FIT Contract nor aware of any condition, event or act that would, with notice or lapse of time or both, result in a default under the FIT Contract;

(c) the Supplier shall not claim, nor be entitled to receive, any Force Majeure relief other than expressly provided in this letter for any event described in the FM Claims nor in respect of any delays caused by the Government of Ontario prior to the date hereof in clarifying the requirements for the final public meeting required pursuant to O. Reg. 359/09 (Renewable Energy Approvals Under Part V.0.1 of the *Environmental Protection Act*); and

(d) except with respect to the FM Claims and as described in Schedule "A", as of the date hereof the Supplier is not aware after due inquiry of any Force Majeure that has occurred or is continuing or of any reason that any Force Majeure may occur.

Please confirm your agreement with this letter by countersigning the enclosed duplicate of this letter below and returning a copy to the OPA. In addition, two copies of the Amending Agreement have been enclosed for your execution. Once the OPA receives your executed copies of the Amending Agreement, the OPA will executed and date the Amending Agreement and provide you with a copy for your records.

If you have any questions or comments in respect of the foregoing, please feel free to contact Bojana Zindovic at bojana.zindovic@powerauthority.on.ca.

Yours very truly,

Michael Killeavy

Michael Killeavy
Director, Contract Management
Ontario Power Authority

Agreed to and Accepted:	
TROUT CREEK WIND POWER INC.	
By:	Date:
Name:	
Title:	

Schedule "A
Other Force Majeure Claims

The attached is **Exhibit "G"** to the Affidavit of
Thomas Schneider, sworn before me
this 25th day of May, 2011

A Commissioner, etc.

KEVIN FREDRICK WENTZEL, a
Commissioner, etc., Province of Ontario,
while a Student-at-Law.
Expires April 29, 2014.

ONTARIO POWER AUTHORITY

120 Adelaide Street West
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T 416-967-7474
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FIT CONTRACT
FORM OF FORCE MAJEURE NOTICE

OPACM-FIT-Force Majeure Notice (2010-07)

SUBMIT BY E-MAIL (PDF WITH SIGNATURE) TO
FIT.Contract@powerauthority.on.ca

Pursuant to Section 10.1 of the FIT Contract, the Supplier is hereby submitting this completed Force Majeure Notice to the Buyer. Capitalized terms not defined herein have the meanings ascribed thereto in the FIT Contract.

☒ This is a new Force Majeure event, start date: January 18, 2011

☐ This is an update to existing Force Majeure No.: ____________

☐ This is a termination notice, termination date: ____________

Date	February 1, 2011	
Force Majeure No.	1	
Title of Force Majeure	Trout Creek Wind Project Regulatory Delay	
Legal Name of Supplier	Trout Creek Wind Power Inc.	
Contract Identification #	F-000655-WIN-130-601	(the "FIT Contract")
Contract Date	April 30, 2010	
Original Milestone Date for Commercial Operation	April 30, 2013	
OPA Approved Revised Milestone Date for Commercial Operation		
Type of Force Majeure	☒ CERTIFICATE/ PERMITTING/LICENCING ☐ TRANSMISSION/DISTRIBUTION SYSTEM ☐ UNANTICIPATED MAINTENANCE /OUTAGE	☐ ACTS OF GOD / EXTREME WEATHER ☐ LABOUR DISPUTES ☐ OTHER (SPECIFY):

1. Description of events leading to Force Majeure (Provide reasonably full particulars of the cause and timing of the events relating to the invoked Force Majeure. Also provide documentary evidence of the same, including, without limitation, the following: newspaper articles, correspondence, emails, notes, reports, memoranda and any other documentation relevant to establishing Force Majeure.)

See attached

2. Effect of Force Majeure (Provide reasonably full particulars of the effect of the Force Majeure on the Supplier's ability to fulfil its obligations under the FIT Contract. Also provide documentary evidence of the same, including, without limitation, the following: reports, policy documents, correspondence, notes, memoranda and any other documentation relevant to establishing the effect.)

See attached

3. Cost of Alternatives available to remedy or remove the Force Majeure (Provide reasonably full particulars of alternatives available to the Supplier to remedy or remove the Force Majeure, together with an estimation of related costs with respect to each alternative. Also provide documentary evidence of the same, including, without limitation, the following: written cost estimates, legal or professional opinions and reports, municipal or other government policy documentation and any other documentation relevant to establishing the cost.)

See attached

4. Commercially Reasonable Efforts (Provide reasonably full particulars of efforts, if any, undertaken or contemplated by the Supplier to remedy or remove Force Majeure. Also provide documentary evidence of the commercially reasonable efforts listed, including, without limitation, the following as applicable: meeting requests with municipal officials, notes from meetings or telephone calls, minutes of meetings, letter or email correspondence with third parties, copies of reports, policies, proposals, newspaper articles and any other documentation relevant to establishing the commercially reasonable efforts.)

See attached

AUTHORIZED SIGNATORY

The Authorized Signatory must be either a signatory of the FIT Contract, a person authorized to receive Notices, or the Company Representative. If not, a Form of Certificate of Incumbency (OPACM-FORM-18A/Corporation or OPACM-FORM-18B/General Partner) must be submitted with this form.

By: ______________________ Date: Feb 1, 2011

Name: Thomas Schneider

Title: President

Legal Name of Supplier: Trout Creek Wind Power Inc.

1. **Description of events leading to Force Majeure**

   Provide reasonably full particulars of the cause and timing of the events relating to the invoked Force Majeure. Also provide documentary evidence of the same, including, without limitation, the following: newspaper articles, correspondence, emails, notes, reports, memoranda and any other documentation relevant to establishing Force Majeure.

A delay in the issuance of Applicant of Record status has resulted in Trout Creek Wind Power Inc. ("the Supplier") not being able to submit a proposal for a wind testing facility and associated permit application in a timely manner. This delay has also resulted in the Supplier not being able to commence the REA process in a timely manner. The delay has been caused by the Ministry of Natural Resources (MNR) and the Ministry of the Environment (MOE). The delay has compromised the schedule for project development to the extent that the Supplier will not be able to meet the milestones and deadlines established in the FIT Contract.

Frequent communication with the Bracebridge Area Office of the MNR began in April 2010, just prior to the award of the FIT contract. In these initial communications, the Supplier raised questions about the ability to receive Applicant of Record Status in a timely manner, and meeting FIT contract deadlines while following the established process for Crown land release. The Supplier prepared a proposal to erect a meteorological tower on the Crown land site, and submitted this to the MNR in advance of a meeting held June 7, 2010.

At the June 7, 2010 meeting, attended by four representatives of the Supplier and eight MNR staff members, discussion focused on the site description package (information the MNR had compiled in relation to the site), the wind testing proposal, and next steps. The minutes of the meeting are contained in Exhibit A.

The MNR provided the Supplier with a "Windpower Applicant Declaration Form" on June 10, 2010. The Supplier submitted the completed form to the MNR six days later. Through discussion with the MNR it was agreed that the public notification commencement date would be left blank because the MNR had requested that the Supplier not issue public notice of the proposal until such time that they had satisfactorily notified and consulted with potentially interested or affected Aboriginal communities. The "Windpower Applicant Declaration Form" as submitted and related correspondence between the Supplier and the MNR is contained in Exhibit B.

MNR began to compile a list of Aboriginal communities requiring notification of the proposal prior to the June 7th meeting. The final list, collaboratively developed by the MNR and the MOE, was not finalized until October 6, 2010. Throughout that period, the Supplier elicited regular updates on progress being made toward finalizing the list and continued to work on other aspects of the wind testing proposal and the wind farm proposal.

On August 19, 2010, the Supplier requested a meeting with the Renewable Energy Facilitation Office (REFO) to discuss the permitting timeline in relation to the FIT contract deadlines. A "Renewable Energy Approval Proponent Pre Submission Consultation Meeting" request was faxed to the MOE on September 1, 2010. A meeting attended by the Supplier, MNR, MOE and REFO was held September 8, 2010. Several concerns were discussed during this meeting:

-The Supplier would like to begin work on studies related to the REA, especially long lead-time studies such as bird studies; however the MNR was showing hesitation in providing guidance on such work as Applicant of Record status had not yet been issued.

-The timeline for submitting the revised wind testing proposal was uncertain as the MNR could not indicate how much time would be required to notify and consult Aboriginal communities.

The minutes of this meeting are contained in Exhibit C.

The MNR informed the Supplier on October 5, 2010, that notification letters had been sent to all Aboriginal communities on the list, and recommended that the Supplier commence public notification as of October 7, 2010. The public notification/consultation period for the wind testing proposal began October 21, 2010 when a notice about the proposal appeared in the *Almaguin News*, and carried through to November 22, 2010. The Supplier was prepared, as of November 29th, 2010, to submit the revised wind testing proposal, complete with a report on the public notification/consultation that took place. Exhibit D contains a copy of the notice as it appeared in the local paper.

Between October 5, 2010, and January 31, 2011, there was frequent correspondence between the Supplier and the MNR. The Supplier was repeatedly informed that Aboriginal consultation was ongoing. Emails and notes from phone conversations during this period relating to Aboriginal consultation and Applicant of Record status are contained in Exhibit E.

On January 18, 2011, the Supplier sent a letter outlining the permitting delay being experienced to the Ontario Power Authority (OPA), the MOE, the MNR, and the REFO. This letter is contained in Exhibit F. It was on this day that the Supplier deemed the delay a cause to invoke Force Majeure.

2. **Effect of Force Majeure**

   Provide reasonably full particulars of the effect of the Force Majeure on the Supplier's ability to fulfill its obligations under the FIT Contract. Also provide documentary evidence of the same, including, without limitation, the following: reports, policy documents, correspondence, notes, memoranda and any other documentation relevant to establishing the effect.

The delay caused by regulatory authorities affected the project development timeline such that the FIT contract deadlines cannot be met. As of January 31, 2011, the Supplier has only nine months in which to erect a wind testing tower, commence the REA process, and complete an REA submission. Exhibit G contains a conceptual project timeline and a schematic of the process being followed for Crown land release and permitting.

A negative financial impact to the supplier is expected due to loss of revenues caused by not being able to meet the Commercial Operation Date.

3. **Cost of Alternatives available to remedy or remove the Force Majeure**

   Provide reasonably full particulars of alternatives available to the Supplier to remedy or remove the Force Majeure, together with an estimation of related costs with respect to each alternative. Also provide documentary evidence of the same, including, without limitations, the following: written cost estimates, legal or professional opinions and reports, municipal or other government policy documentation and any other documentation relevant to establishing the cost.

There are no alternatives available to remedy or remove the Force Majeure. A delay was caused by regulatory authorities, which affected the project development timeline such that the FIT contract deadlines cannot be met.

4. **Commercially Reasonable Efforts**

   Provide reasonably full particulars of efforts, if any, undertaken or contemplated by the Supplier to remedy or remove Force Majeure. Also provide documentary evidence of the commercially reasonable efforts listed, including, without limitation, the following as applicable: meeting requests with municipal officials, notes from meetings or telephone calls, minutes of meetings, letter or email correspondence with third parties, copies of reports, policies, proposals, newspaper articles and any other documentation relevant to establishing the commercially reasonable efforts.

The Supplier has been in regular contact with the MNR on this matter, as is documented in the attached correspondence. The Supplier has met with the MNR and MOE to discuss the delay and project timeline challenge. The Supplier understands that until we receive Applicant of Record status, we cannot proceed further in the Crown land release process, or in the REA process. The Supplier had not been able to identify any further efforts that can be made to remedy or remove Force Majeure.

Exhibit A

Schneider Power	**Project:**	Trout Creek Wind Farm
	SPI Project No.	C010
	Windpower File:	WP-2008-180
	Meeting Date:	Monday June 7th, 2010
	Meeting Time:	1:30pm
	Report Date:	Thursday June 10th, 2010
MEETING REPORT NO. TC-01	**Recorder:**	Sarah Raetsen and Janet Oswald
	Page 1 of 5	

Note: If any of the contents of this meeting report differ in any respect from your own recollection of the points discussed or decisions reached, please notify us immediately. In the meantime, we will proceed in accordance with the understanding described herein.

LOCATION: MNR Bracebridge Area Office

PRESENT:
Kim Benner (MNR PS)
Joe Johnson (MNR PS)
Laura Heidman (MNR SR)
Karrie Bennett (MNR PS)
Phung Tran (MNR PS)
Anne Collins (MNR PS)
Trevor Griffin (MNR PS)
Erin Cotnam (MNR SR) *(via telephone)*
Sarah Raetsen (SPI)
Mathieu Archambault (SPI)
Amar Kher (SPI)
Janet Oswald (SPI)

PURPOSE: To discuss the Trout Creek Site Release Application and Testing Proposal

Action By

1. **Introductions**
   - Meeting participants introduced themselves and provided their representation.

2. **Overview of Site Release Application**

a. **Brief history of the company and proposal**
   - M. Archambault gave an overview of other SPI projects; one on Spring Bay on Manitoulin Island and he noted other projects in Nova Scotia, Bahamas and Dominican Republic
   - M. Archambault advised that SPI's 10 MW proposal in Laurier Township is intended to fit well with what the government is asking from energy proponents
   - S. Raetsen presented background information about the project, including a description of the work that had been completed on Schneider Power Inc.'s (SPI's) private land location prior to making an application for Crown Land.

- S. Raetsen: SPI has a signed Feed-in-Tariff (FIT) contract with the Ontario Power Authority (OPA) for the eight grid cells as outlined in the SPI application to develop wind power on Crown Land. Contract is for a 20 year term.

b. Site Description Package (Draft)

- General

  K. Benner: Work has begun on the Windpower Site Description Package (SDP) and a map showing values has been prepared. Both the map and the Draft SDP were distributed to meeting participants.

- Information
  - Aboriginal values and traditional activities

    L. Heidman: This information will be determined through consultation with Aboriginal Communities. MNR is working on preparing a list of Aboriginal Communities to consult with and is coordinating with the Ministry of the Environment (MOE) on this. (L. Heidman advised that this list will likely differ from the list generated during the earlier Environmental Assessment (EA) work on the private land). The Ministry of Natural Resources (MNR) list will be sent to the MOE within the next few days. MNR

    MNR will be responsible for initiating dialogue with Aboriginal Communities. A letter will be sent out to communities identified on the list with an invitation to meet with the MNR. If the MNR does not receive a response they will follow-up with direct phone calls. Aboriginal Communities on the list must be notified about the wind testing proposal before the general public is notified. A modified version of the proposed newsletter (prepared by SPI) will be published in the Anishinabek News (MNR will work with SPI to put this together). This can happen at the same time as a notice is placed in a local paper such as the Almaguin Forester.
  - Cultural heritage values

    These will be determined through work associated with the Renewable Energy Approval (REA).
  - Access points and access road locations

    MNR expressed concern that new access points and access road would open up that area of Crown Land to uncontrolled use. MNR's preference would be for the existing logging roads to be used as much as possible (improved if necessary) in order to minimize the need for new roads. SPI should provide MNR with more information about access road to wind testing site (GPS routes, etc). SPI
  - Tourism

    S. Raetsen suggested that the Public Observatory proposed in the area by the Municipality of Powassan be added to the list of site features. *See attached map and correspondence with* *the Municipality of Powassan.*

- Transmission line route
  M. Archambault described approaches to installing transmission line (above ground, conduit/below ground).
- Research plot
  P. Tran: There is an old research plot on the site that is no longer being used. It was previously used for research on songbirds, salamanders and small mammals. The plot was used by the main MNR office and the information related to it is sensitive; therefore, the district office has had some difficulty obtaining information about the plot. The presence of the plot is not likely to be of concern.
  SPI may need to ensure that any flagging or markers that are currently in place remain so. Information about the plot will be provided to SPI as it becomes available. MNR
- Resource Management Plans
  The site is subject to the French-Severn Forest Management Plan (FMP). Westwind Forest Stewardship Inc. holds a Sustainable Forest Licence (SFL) on the land. SPI would need a Forest Resource Licence (FRL) for the area to be cleared for the met mast. The SFL will need to be amended for the testing proposal and/or the wind farm project. SPI MNR
- Aggregates
  The map provided by MNR shows two aggregate sites northwest of the site. SPI needs to determine if these sites will be impacted by the transportation corridors or infrastructure associated the testing proposal or wind farm. SPI
- Bat and bird habitat
  Bat and bird assessments will be completed as part of the REA. Avifauna report previously prepared in July 2006 should be viewed as a background document only. SPI
- Species of Concern/Threatened/Endangered (CTE) Species SPI
  P. Tran: There are no records of occurrences and low potential for Endangered or Threatened species at this site.
- Other habitat considerations
  SPI will need to look at significant wildlife habitat, paying particular attention to the wetland areas and habitat for nesting bird species.

- Information gaps
  - Cultural heritage values
    L. Heidman: Aboriginal Communities may indicate that they have an interest in the cultural heritage assessment (and natural heritage assessment).

SPI

- Potential stakeholders
  - Cottage Association
    SPI needs to identify if there is a cottage association in the

Sausage Lake area and the appropriate contact person(s).

- Westwind

3. **Overview of testing proposal**

a. **Approval and permitting requirements including advice on public consultation, Aboriginal consultation, etc.**

- M. Archambault described the wind testing tower, its installation, and SPI's timeline. SPI anticipates receiving the approvals to construct the met tower this summer with an anticipated date of summer 2011 for construction of the wind farm project.
- J. Johnson and L. Heidman both advised that it is not likely that all necessary permits will be in place in time for the tower to be installed this summer.
- K. Benner advised that the Declaration letter should be sent by SPI to MNR following the pre-screening meeting. SPI asked MNR for the Declaration form to be sent to them. SPI/MNR
- There was discussion around whether SPI was already in a Non-Competitive Process, or still needs to confirm intent to proceed non-competitively and pay the associated fee. This needs to be clarified. SPI/MNR
- There was significant discussion around which section of the Approval and Permitting Requirements Document (APRD) would apply to the wind testing proposal - 5.1 (testing project without construction of a transportation system) or 5.2 (testing project where construction or modification of a transportation system is required). SPI will provide greater detail about the proposed access route, and MNR will indicate which, if any, of the requirements under section 5.2 will need to be met. E. Cotnam indicated that the District could use discretion in deciding what approach is reasonable and appropriate for the scale of work being proposed. The possibility of applying a "hybrid" of the requirements under sections 5.1 and 5.2 was suggested. Further discussion focused on whether a Class EA-for Resource Stewardship and Facility Development Projects (RSFD) would be required for multi-purpose roads on Crown land (new roads that will be open for public access or existing roads that are proposed to be modified) for the renewable energy generation facility. The RSFD for roads used/created for the testing facility does not apply. Test proposals must meet APRD requirements. This will be clarified once new information about the preferred access route is provided by SPI to the MNR.
- T. Griffin: SPI could begin some of the natural heritage field work for the wind farm project while the testing facility is operational.
- T. Griffin: SPI is advised to submit revised wind testing proposal together with permit applications.

Permits that are required for wind testing project:

i. Letter of Authorization
ii. Land Use Permit
iii. Forest Resource Licence (following amendment to existing licence,

and exemption under Section 47 of Crown Forest Sustainability Act)

iv. Work Permit (depending on the type of work that will be required for the wind testing)

4. **Next Steps**

- SPI to send updated windpower testing proposal to MNR with additional details on access to the site.
- MNR to obtain Aboriginal Communities notification list and provide notification to the communities on the windpower testing proposal.
- MNR to provide SPI with the Windpower Application Declaration Form.

Exhibit B

Windpower Applicant Declaration Form

For the Windpower opportunity at;

Laurier (Township/Location) Parry Sound (MNR District),

known as Windpower Application Number WP-2008-180,

as per the map provided by District staff at the pre-screening meeting.

I/we declare that I/we have chosen the following method of site release for this Windpower application.

______ Competitive Process

✓ Non-Competitive Process

I/we as the Applicant, acknowledge the following:

GENERAL TERMS

a) that I/we have read and understand the Site Description Package and any other information provided by the Ministry of Natural Resources (MNR) during the pre-screening meeting or through the MNR Renewable Energy extranet site (including the template of the Applicant of Record letter).

b) I/we agree to read, understand and comply with all applicable policies, procedures, legislative requirements, guidelines and tenure documents.

c) I/we will be required to make submissions to the MNR as required for permits, approvals, environmental assessment review or any other procedural or legislative requirement.

d) I/we will be responsible for acquiring all permits and approvals as required under applicable provincial, federal and/or municipal legislation and any other policies or guidelines

e) In the event that I/we decided to proceed with a Windpower development, I/we will enter into a Crown Lease Agreement in substantially in the same form as those provided on the MNR extranet site

f) I/we agree to complete public notification as prescribed by the MNR. A summary of comments received and a plan to address any potential concerns / issues that resulted from public notification will be included in the Windpower Testing Proposal submission.

g) No legal relationship has been created between the MNR and the applicant.

h) If this proposal is from a corporation, I/we acknowledge that proposal must be signed by an officer of the corporation, indicating the signing officer's official capacity and stating that the signing officer is authorized to sign and submit the proposal on the corporation's behalf.

APPLICANT COSTS

i) that any required proposals will be prepared at the sole cost and expense of the Applicant. The Applicant will bear all costs and expenses in connection with the proposal, including, without limitation, any expert advice required. The MNR shall not be liable to pay any Applicant costs under any circumstances. In particular, the MNR will not reimburse the Applicant in any manner whatsoever in the event of rejection of any or all proposals. The Applicant irrevocably and unconditionally waives any claims against the MNR relating to the Applicant's costs.

CONFIDENTIALITY PROVISIONS

j) Any document or communication to the MNR becomes Crown property and is subject to the provisions of the *Freedom of Information and the Protection of Privacy Act (the Act)* R.S.O. 1990, c.F.31 as amended and may be released under that Act.

k) I/we will clearly indicate in a separate confidentiality statement, in a form provided by myself/us, any confidential information for which confidentiality is to be maintained by MNR and its technical advisors. Those documents considered confidential should be stamped specifically as 'Proprietary and Confidential'. This confidentiality would include any documents or materials which identify a trade secret or provide communications and alliances, commercial or technical information, which are being supplied in confidence, and where disclosure could be harmful to the Applicant's competitive position, or result in undue loss or gain to any person or organization.

l) Any information provided to MNR by the applicant through this site release process that is not identified in k) as 'Proprietary and Confidential' may be disclosed.

RESERVED RIGHTS OF THE MNR

m) MNR may verify with the Applicant, or with a third party any information set out in any proposal.

n) MNR may reject any, all, or portions of the proposal received for being incomplete or for failure to meet any criteria set forth in the Windpower Site Strategy Requirements document.

o) MNR may reject any or all proposals in its absolute discretion.

p) MNR may reject any Applicant whose proposal contains material misrepresentations or any other materially inaccurate or misleading information.

q) I/We hereby consent to the public release of the company name (or individual's name if the application is not from a corporation), contact name and phone number. The company (or individual's) name and phone number may appear on the MNR Renewable Energy Extranet site.

r) these reserved rights are in addition to any other express rights or any other rights which may be implied in the circumstances and the MNR shall not be liable for any expenses, costs, losses or any direct or indirect damages incurred or suffered by any Applicant or any third party resulting from the MNR exercising any of its express or implied rights under this windpower site release process.

PUBLIC NOTIFICATION
(Note: This is applicable for applications proceeding through the non-competitive process).

Public Notification will commence on _____, 20__.

I/we agree that the following information may appear on the MNR Renewable Energy Extranet Site on the commencement date of Public Notification.

Company Name: Trout Creek Wind Power Inc., a wholly owned subsidiary of Schneider Power Inc.

Contact Name: Sarah Raetsen

Contact Phone Number: (416) 847-3724, ext. 229

Sarah Raetsen
Signature of Witness

Sarah Raetsen, Head of Envt'l Planning
Name of Witness:

June 16, 2010
Date of Signature:

Signature of Applicant Representative

Thomas Schneider, President.
Name and Title of Applicant Representative:

16/06/10.
Date of Signature:

I have authority to bind the proponent.

From: Janet Oswald
To: "Benner, Kim (MNR)"
Subject: RE: APRD requirements and timelines
Date: July-16-10 4:08:00 PM

Thanks Kim for getting this to me so quickly. I hope you have a nice weekend too, --Janet

From: Benner, Kim (MNR) [mailto:kim.benner@ontario.ca]
Sent: July-16-10 4:06 PM
To: Janet Oswald
Cc: Tran, Phung (MNR)
Subject: APRD requirements and timelines

Hi Janet,

As we discussed today, Schneider Power should follow the requirements for Section 5.1 – Testing Projects on Crown land where no construction of a transportation system is required.

Consideration of protected properties, archaeological and heritage resources are required under Section 5.1 and I have asked Renewable Energy Section to provide advice on how to meet this requirement.

The Windpower Application Declaration Order was received by us on June 16, 2010. The recently updated procedures for Onshore Windpower Development on Crown land states that the Applicant will conduct public notification within 60 days of submitting the Declaration Order. We are still waiting for approval to consult with the identified Aboriginal communities. Since public consultation cannot occur before Aboriginal community notification, the responsibility for the delay lies with the province. To address this timing issue, MNR will allow 60 days for public consultation following Aboriginal community notification.

We recommend that the wind test facility and access tail location be such that impact on significant wildlife habitat is minimized. As we discussed today, SP's consultant who would be carrying out the natural heritage assessment for the windpower proposal should speak directly to Phung Tran, Landscape Planning Biologist to discuss technical aspects of this assessment. This may be an opportunity to discuss what methods could be used to determine the presence of significant wildlife habitat within the test facility site as well.

Have a nice weekend,

Kim

Kim Benner
District Planner
Parry Sound District MNR
(705) 646-5520
(705) 645-8372 (fax)
kim.benner@ontario.ca

Exhibit C

Schneider Power	Project:	Trout Creek Wind Farm
	SPI Project No.	C010
	Windpower File:	WP-2008-180
	FIT Contract No.:	F-000655-WIN-130-601
	Meeting Date:	Wednesday September 8, 2010
	Meeting Time:	2:00pm
	Report Date:	Thursday September 9, 2010
MEETING REPORT NO. TC-02	Recorder:	Sarah Raetsen and Janet Oswald
	Page 1 of 2	

Note: If any of the contents of this meeting report differ in any respect from your own recollection of the points discussed or decisions reached, please notify us immediately. In the meantime, we will proceed in accordance with the understanding described herein.

LOCATION: MOE, Environmental Assessment and Approvals Branch
2 St. Clair Avenue West, 12th Floor

PRESENT:
Narren Santos (MOE)
Christopher Quirke (REFO) *(via telephone)*
Erin Nixon (MNR) *(via telephone)*
Kim Benner (MNR) *(via telephone)*
Sarah Raetsen (SPI)
Janet Oswald (SPI)
Wayne Curtis (SPI)

PURPOSE: To discuss SPI's concerns with respect to meeting the deadlines in the OPA FIT Contract given the pace the project work is proceeding at to date

Action By

1. **Introductions**
   - Meeting participants introduced themselves and provided their representation.

2. **Purpose of the Meeting**
   - S. Raetsen described the purpose for requesting this meeting:
     - To bring forward concerns with respect to meeting the deadlines in the OPA FIT Contract given the pace the project work is proceeding at to date.

3. **Progress To Date**
   - S. Raetsen described a history of the project and the status of the project to date:
     - Project on private land initiated in 2006.

- Some Environmental Studies completed, two Public Information Centres held.
- Project halted while SPI applied to the window opportunity to develop windpower on Crown land.
- No decision was made, so SPI continued to wait.
- SPI was encouraged to submit the Crown land application to the FIT program when the *Green Energy Act* was proclaimed.
- SPI's application was successful. FIT Contract awarded on April 30, 2010.
- Discussions began with the MNR in April to discuss the process going forward.
- Pre-Screening Meeting held with the MNR in June. Since then, SPI has been waiting for the MNR to undertake Aboriginal Consultation. SPI has been unable to proceed with any work until that consultation is complete.

4. **Concerns**

- SPI raised the concern that we would like to begin some preliminary natural work that could be used towards the REA, however, when we ask the MNR for guidance on the features to be looked at, they have hesitated in providing us with that assistance.
  - E. Nixon noted that once the met. tower is erected, then SPI can conduct the records review for the REA. Also note that once SPI has a wind farm layout, then the MNR will comment.
  - C. Quirke noted that it is a sequential process and that he public will want to see that the steps are being followed in the appropriate order. This was echoed in comments made by N. Santos.
- C. Quirke noted that the SPI should speak directly to the OPA about matters relating to contractual issues, while keeping the REFO informed of developments on that front.
- From the general discussion another timeline challenge was identified. K. Benner indicated that once notices were sent to Aboriginal communities it is not possible to know when the MNR will be satisfied that the duty to consult has been met. The MNR will pass on any information generated from their consultation with Aboriginal communities to SPI to include in the windtesting proposal; however, it will be difficult for SPI to predict when the proposal might be submitted as the period for Aboriginal consultation is somewhat open-ended.

5. **Next Steps/Moving Forward**

- The Parry Sound office (MNR) is ready to put out some of the Aboriginal Consultation letters. K. Benner indicated that there were some discrepancies between the lists generated by MNR and MOE therefore some follow-up work was still necessary before all the notices could be sent out. E. Nixon indicated that the MNR still had to determine whether the two notices to Aboriginal communities (general notice of application, and notice of proposal for testing facility) could be combined. This would be the preferred approach given the time constraints. The Windpower Testing Proposal cannot be submitted until both Aboriginal and Public Consultation are completed.

- Applicant of Record (AoR) status is issued after both Aboriginal and Public Consultation are completed.
- SPI is going to contact the OPA to discuss the FIT contract timelines and gain an understanding of the deadlines. C. Quirke from the REFO noted that he would like to be included in discussions with the OPA.
- N. Santos suggested that SPI submit the REA Project Description Report (PDR) as soon as possible so that they (MOE) can start preparing the list of Aboriginal Communities to engage with (although it will be the same as the list used for the windtesting proposal). She suggested that the PDR describe negative environmental impacts.
- E. Nixon encouraged SPI to begin work on the records review requirements of the REA process and the site investigation protocol.
- N. Santos will send SPI a copy of the draft screening checklist to help SPI ensure the REA submission will have every chance at an effiient review. N. Santos

Exhibit D

MAYORALS: Linda Andersen addresses the crowd at the Nipissing Community Centre ahead of other hopefuls Pat Haufe, centre, and Kalvin Young.

Single jab thrown at township debate

Rob Learn
News Staff

NIPISSING – It was well over an hour into the debate, but eventually there was a jab thrown between the candidates for mayor for the Township of Nipissing.

Councillor and mayoral candidate Pat Haufe took the almost indirect swing at opponent Kalvin Young during a question-and-answer portion of the evening, pointing out what he believes to be a difference between the two.

"I have not gone to ROMA (Rural Ontario Municipal Association). I have not gone to OGRA (Ontario Good Roads Association). I have not gone to FONOM, AMO... I have not cost the taxpayer a dime going to conferences... I'm not going to spend your dollars on conferences I don't see a need for," said Haufe.

Young, also a councillor running for the mayor's position, stood immediately after the response noting that the statement was aimed in his direction.

"done," said Chalkley.

Incumbent councillor Cathan, the only incumbent councillor candidate, read of a long list of experience that dates back to 1969 when he served a term on council. In 1973 he became Nipissing's road superintendent until 1987 and has served on many boards and attended many conferences.

"At these conferences you get to talk to the head of ministries and MPPs and learn what grants are available and knowledge to help with the management of the township's affairs," said Culham.

Steve Kirkey said he moved to the township in 1987 and has worked at Falconbridge for 30 years where he is the emergency response team coordinator. He has also been on the Nipissing Fire Department for 15 years.

"We in Nipissing Township enjoy a really good quality of life. It is one of the few places that you can afford to live and retire and I would like to keep it that way," said Kirkey.

Roads, pits, wetlands on candidates' agenda

Mary Beth Hartill
News Staff

BURK'S FALLS – With only a few days left in their election campaigns the candidates for Ryerson reeve have been handing door-to-door fielding questions that will impact the next four years.

Both men, incumbent Reeve Glenn Miller and Paul Van Dam have been sending out flyers, dropping them in mailboxes and greeting residents at their doorstep.

Van Dam says taxes and assessments, particularly for waterfront residents, are primary concerns. He says wetlands and roads are also of concern.

The Ontario Municipal Board hearing regarding the wetlands issue in Ryerson is coming up on Nov. 15 and Miller is looking forward to getting that resolved so they can complete the official plan, which he says is about 80 per cent adopted.

"We just had a meeting with our lawyer and our planner and what is our position on that's one of the issues facing the township. The other issue is new development in the township, obviously pits and quarries have come to the foreground," he said.

"It seems that whenever there's an election on everybody wants to open up a pit."

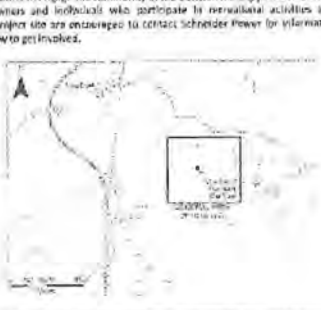


Exhibit E

Janet Oswald

Subject:	Phone call with Kim Benner re. info to local authorities
Entry Type:	Phone call
Start:	Fri 01/10/2010 4:00 PM
End:	Fri 01/10/2010 4:10 PM
Duration:	10 minutes
Contacts:	Kim Benner
Categories:	Trout Creek

Kim Benner called in response to voicemail I left her regarding my question about sending windtesting proposal information (the map) to local authorities (e.g. Laurier LSB). She indicated that it seemed a reasonable thing to do, but could not officially give us the go-ahead.

Kim also mentioned that the letter to the Metis community was going through final approval (the tone of the letter required final approval?), and that she expected it to be sent out early next week. She also mentioned that the legal team was meeting next week to discuss the remaining communities in order to finalize the Aboriginal consultation list.

Janet Oswald

Subject:	Voicemail left with Kim Benner regarding consultation with Aboriginal communities
Entry Type:	Phone call
Company:	MNR
Start:	Fri 29/10/2010 9:47 AM
End:	Fri 29/10/2010 9:47 AM
Duration:	0 hours
Contacts:	Kim Benner
Categories:	Trout Creek

Left Kim a voicemail asking if they had received any comments/feedback from Aboriginal communities. Also asked if she could advise me on how long the MNR would want to wait for comments to come in.

Janet Oswald

Subject:	Follow up with Kim on question regarding AoR and inviting Aboriginal communities to the CAC
Entry Type:	Phone call
Company:	MNR
Start:	Tue 09/11/2010 2:59 PM
End:	Tue 09/11/2010 2:59 PM
Duration:	0 hours
Contacts:	Kim Benner
Categories:	Trout Creek

Left voicemail with Kim to follow up on the questions I had sent:

1. Regarding needing Applicant of Record status prior to submitting the proposal
2. Inviting Aboriginal communities to the first meeting of the CAC

Janet Oswald

From:	Benner, Kim (MNR) [kim.benner@ontario.ca]
Sent:	November-25-10 8:48 AM
To:	Janet Oswald
Subject:	RE: FN notification update
Attachments:	addresses of FN communities.doc
Categories:	Trout Creek

Hi Janet,

Here is the list of addresses for the FN communities that we contacted...sorry for the delay in sending this.

Kim

-----Original Message-----
From: Janet Oswald [mailto:JOswald@schneiderpower.com]
Sent: Wednesday, November 17, 2010 3:32 PM
To: Benner, Kim (MNR)
Subject: RE: FN notification update

Hi Kim,

Are you able to provide us with the contact information for the Aboriginal communities that the MNR contacted about our proposal? We have the list of communities, however it makes sense to address the invitation to participate in the CAC to the same individuals as the notification letter.

Thanks,

-Janet

-----Original Message-----
From: Sarah Raetsen
Sent: November-16-10 4:18 PM
To: Benner, Kim (MNR); Janet Oswald
Subject: RE: FN notification update

Thanks Kim,

We have been in contact with the Municipality of Powassan on the windtesting proposal. Their Deputy Clerk expressed interest in joining the CAC. The municipality has not submitted formal comments on the windtesting proposal; however, we will follow up with them on that matter.

We will discuss inviting the Aboriginal Communities in participating on the CAC.

Thanks for the update,
Sarah

-----Original Message-----
From: Benner, Kim (MNR) [mailto:kim.benner@ontario.ca]
Sent: November 16, 2010 4:05 PM
To: Janet Oswald; Sarah Raetsen

Subject: RE: FN notification update

Hi,

I'm sorry to take so much time to respond to these questions. I spoke with Leslie Joynt today and she advised that she has not heard from any of the communities notified. She will follow up with some of them this week. I reminded her that the public consultation period will be closing next week and you would be looking for a decision on the Applicant of Record status shortly after that.

I know that you have kept the Village of Powassan updated on the windpower project. Have they provided comments to you?

We would not discourage you from asking communities if they would be interested in participating in a Community Advisory Committee for the project. We have invited communities to participate in various advisory groups for certain projects such as Forest Management Planning and Water Management Planning before.

Please let me know if you have further questions. I hope to provide you with another update early next week.

Kim

-----Original Message-----
From: Janet Oswald [mailto:JOswald@schneiderpower.com]
Sent: Tuesday, November 02, 2010 3:12 PM
To: Benner, Kim (MNR)
Subject: RE: FN notification update

Thanks Kim.

I have a few other questions for you, I hope you do not mind.

Sarah and have been pleased with the interest shown in the Community Advisory Committee that we have proposed. We would like to extend an invitation to the Aboriginal communities identified as potentially having an interest in our project to participate in the committee. Is it appropriate for us to contact the communities with this invitation at this point? We are still a bit unclear on our role in Aboriginal consultation for this project now that it is on Crown land. Your advice would be greatly appreciated.

Also, it is our understanding that we cannot submit our windtesting proposal until we have Applicant of Record status. We would like to submit our revised windtesting proposal as soon as possible after the public comment period has ended and the MNR is comfortable with the amount of time allowed for consultation with Aboriginal communities. Do you know when the decision regarding issuance of an Applicant of Record letter will be made? Is this a process that can be commenced now?

Thanks,

-Janet

-----Original Message-----
From: Benner, Kim (MNR) [mailto:kim.benner@ontario.ca]
Sent: November-01-10 9:56 AM
To: Janet Oswald
Subject: I: FN notification update

Hi Janet,

Thank you for your message on Friday. I sent a note to Leslie Joynt to see if there was any news re. the notification and a possible answer to your question about the length of time that we might wait for a response. I haven't heard from Leslie yet, but I would expect that we would wait at least until Nov. 22nd when the public consultation period ends and then decide a course of action from there. I'll talk more with Leslie about this and get back to you as soon as possible.

Kim

Janet Oswald

From: Benner, Kim (MNR) [kim.benner@ontario.ca]
Sent: November-25-10 8:35 AM
To: Janet Oswald
Subject: I: FN consultation

Categories: Trout Creek

Hi Janet,

When speaking with the FN communities that were sent the notification letter, Leslie was advised that there is a community needs some additional time to discuss the proposal with their community. We will need to wait until the week of December 6th for their comments.

Please call if you have any questions.

Thanks!

Kim

Janet Oswald

Subject:	Call with Kim re: Scarlett Janusas and LUP fees
Entry Type:	Phone call
Company:	MNR
Start:	Fri 03/12/2010 2:30 PM
End:	Fri 03/12/2010 2:35 PM
Duration:	5 minutes
Contacts:	Kim Benner

Kim called to let me know that Scarlett had been in touch with her about our project. Kim wanted to confirm that we had hired her. Kim has put Scarlett in touch with Leslie Joynt to get information about the site. Scarlett had asked about consultation with Aboriginal communities and if she should wait until the MNR had finished their process. Kim advised that they should be wrapping it up soon so hopefully it wont be an issue.

Kim will get back to me next week with information about the fees associated with the windtesting proposal (e.g. LUP) and AoR.

Janet Oswald

From: Benner, Kim (MNR) [kim.benner@ontario.ca]
Sent: December-09-10 1:56 PM
To: Janet Oswald
Subject: Update
Attachments: AoR.doc

Categories: Trout Creek

Hi Janet,

I spoke with Leslie Joynt and she is going to follow up with FN consultation this week.

Re. the Applicant of Record Template, I was sent the latest template (see attached).

Also, I've asked for an LUP cost estimate – still waiting for a response.

Kim

Janet Oswald

From:	Benner, Kim (MNR) [kim.benner@ontario.ca]
Sent:	December-17-10 3:46 PM
To:	Janet Oswald
Subject:	FN Consultation
Categories:	Trout Creek

Hi Janet,

Leslie Joynt did some follow-up with First Nations that were sent nofication letters. You'll recall that the one community wanted to discuss the proposal at a meeting on Dec. 3rd but I understand that the meeting was rescheduled for mid-January. I advised my manager of this delay and we hope to be able to issue the AoR letter as soon as we can following this meeting if there are no concerns brought to our attention.

I'm still waiting for an estimate for the LUP from Tim Cavanagh. Sorry for this delay. I would suggest that you call Tim if you need this estimate within the next 2 weeks. His number is (705) 646-5510.

I will be on vacation until January 4th. If you wish to talk to someone about the project or FN consultation, please call my supervisor, Anne Collins at (705) 646-5553.

Thanks and Happy Holidays, Janet!

Kim

Janet Oswald

Subject:	Update call with Kim Benner
Entry Type:	Phone call
Company:	MNR
Start:	Fri 14/01/2011 4:11 PM
End:	Fri 14/01/2011 4:21 PM
Duration:	10 minutes
Contacts:	Kim Benner
Categories:	Trout Creek

Called Kim Benner for Trout Creek update:

- Meeting with Chiefs was today. K. Benner will get in touch with Leslie Joynt to determine outcome and report back to me Monday afternoon.
- The LUP will cost $268 (for 1.5 ha, which includes $150 admin fee). Kim thinks that there is a form for the LUP application and will get that to me Monday.
- Erin Cotnam is on mat. leave and has been replaced by Rebecca Dixon (705-755-5355). Kim will set up a conference call with Rebecca, or perhaps someone above her so that we can sort out all the fees and when they need to be paid.
- I gave Kim heads up that we are sending update letter to all agencies to highlight delay and timeline issues. She definitely thinks that it is time to put the pressure on.
- Basically, should expect Kim to get back to me on Monday with all this info.

Janet Oswald

Subject:	Call from Kim Benner
Entry Type:	Phone call
Company:	MNR
Start:	Tue 18/01/2011 4:00 PM
End:	Tue 18/01/2011 4:10 PM
Duration:	10 minutes
Contacts:	Kim Benner
Categories:	Trout Creek

- Got a call from Kim Benner
    - Proposal did not make it onto agenda of recent Chiefs' meeting (it is Magnetawan FN that raised a concern).
    - Rebecca Dixon is making call to follow up on the $20,000 fee.
    - Kim will get me LUP form.
    - Leslie will follow up with Chief on Friday.
    - Kim will call me tomorrow to update.
    - Apparently they might be open to us submitting the proposal and permit applications without the Aboriginal consultation being complete. Kim will speak with managers.

Exhibit F

Schneider Power

a QUANTUM Company

[illegible]
Toronto, Ontario, Canada
[illegible]

schneiderpower.com

January 17, 2011

To:

FIT Program	General contact (fit@powerauthority.on.ca)	Ontario Power Authority
Michael Lyle	General Counsel and Vice President, Legal, Aboriginal and Regulatory Affairs	Ontario Power Authority
Michael Killeavy	Director, Contract Management Electricity Resources	Ontario Power Authority
Perry Cecchini	Manager	Ontario Power Authority
Doris Dumais	Director, Approvals Program	Ministry of the Environment
Kim Benner	District Planner	Ministry of Natural Resources
Rebecca Dixon	Policy and Program Advisor, Renewable Energy Program	Ministry of Natural Resources
Jim Beal	Sc Regional Coordinator, Renewable Energy Program	Ministry of Natural Resources
Kevin Edwards	Program Advisor, Business Development & Industry Liaison, Renewable Energy Program	Ministry of Natural Resources
Tomas Nikolakakos	Senior Project Advisor	Renewable Energy Facilitation Office
Christopher Quirke	Team Lead	Renewable Energy Facilitation Office

Dear Sir/Madam,

RE: Status Update and REA Timeline Concerns regarding Trout Creek Wind Project (FIT Identification # F-000655-WIN-130-601; FIT Reference # FIT-F85MM5Z; Contract Date April 30, 2010).

BACKGROUND & CURRENT STATUS

The Trout Creek Wind project is proposed by Trout Creek Wind Power Inc., a wholly owned subsidiary of Schneider Power Inc. The Projects was awarded a FIT contract, which was executed April 30, 2010. The Project is proposed at a location on Crown land. When the Project was first conceived, a meteorological mast was erected at the location on private land approximately 1km west of its Crown land location. Schneider Power is currently seeking approval to erect a second meteorological mast at a location on the current Crown land site.

Schneider Power is awaiting Applicant of Record status so that a proposal for a wind testing tower can be submitted and the REA officially launched through the release of a public notice and the Project Descriptions report as per O. Reg. 359/09 requirements. Field work and reporting with regards to the natural heritage and cultural heritage components of the REA have commenced.

TIMELINE CHALLENGES

Schneider Power has as of yet not been able to officially launch the REA process because it has not been granted Applicant of Record status. The delay that has been experienced in obtaining Applicant of Record status is currently compromising the ability of the Project to meet milestones associated with the FIT contract.

According to the terms and conditions of the FIT contract, Schneider Power has interpreted the key project milestone dates as follows:

Contract Date: April 30, 2010

Deadline to submit complete Notice to Proceed (NTP) Request: October 30, 2012
Six months prior to the Milestone Date for Commercial Operation

Milestone Date for Commercial Operation: April 30, 2013
Three years after the Contract Date

Documentation of a complete REA is required as a pre-requisite to submitting a NTP Request. Working back from the NTP Request deadline and factoring in a possible six month Environmental Review Tribunal hearing and six months for the Ministry of the Environment to coordinate the review of the REA and issue a decision, the REA will need to be submitted by October 2011, at the latest, in order to meet the NTP Request deadline.

REQUEST FOR EXPEDITING PROCESS

1. Schneider Power requests that a letter of Applicant of Record be issued immediately and that review and processing of the wind testing proposal and associated permit applications be expedited.

2. Schneider Power is submitting a Project Description Report to the MOE as per section 14 of O. Reg. 359/09, in order to obtain a list of Aboriginal communities that have a right or interest related to the proposed project. A list of communities has already been provided by the MNR in association with consultation activities they have undertaken in relation to the wind testing proposal. It is Schneider Power's understanding that this list was generated collaboratively with the MOE, and that it is not expected to differ from the list that is now to be provided. The original list named the following communities:

    - Shawanaga First Nation
    - Dokis First Nation
    - Nipissing First Nation
    - Henvey Inlet First Nation
    - Magnetawan First Nation
    - Métis Nation of Ontario's North Bay Métis Council

Schneider Power requests that the confirmation of this list be expedited so has to avoid further delays in launching the REA process for the Trout Creek Wind project.

We look forward to working in a coordinated manner with the appropriate government representatives to ensure that the current delay is resolved and that further delays in the permitting and approval process are avoided.

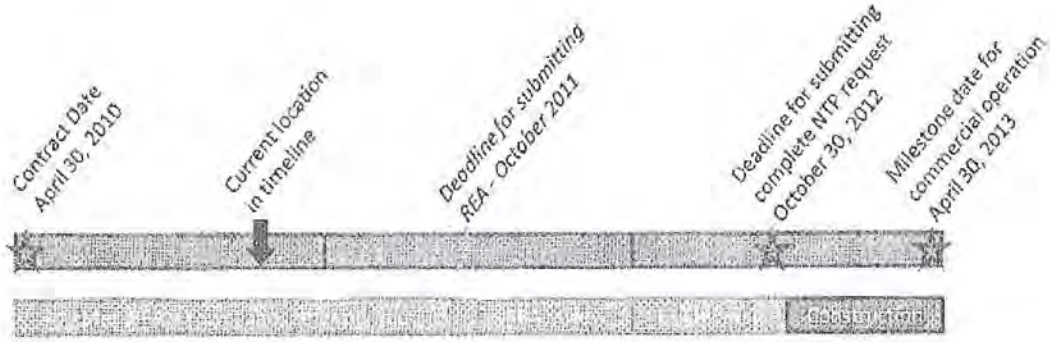
SINCERELY,

SCHNEIDER POWER INC.
Thomas Schneider
President

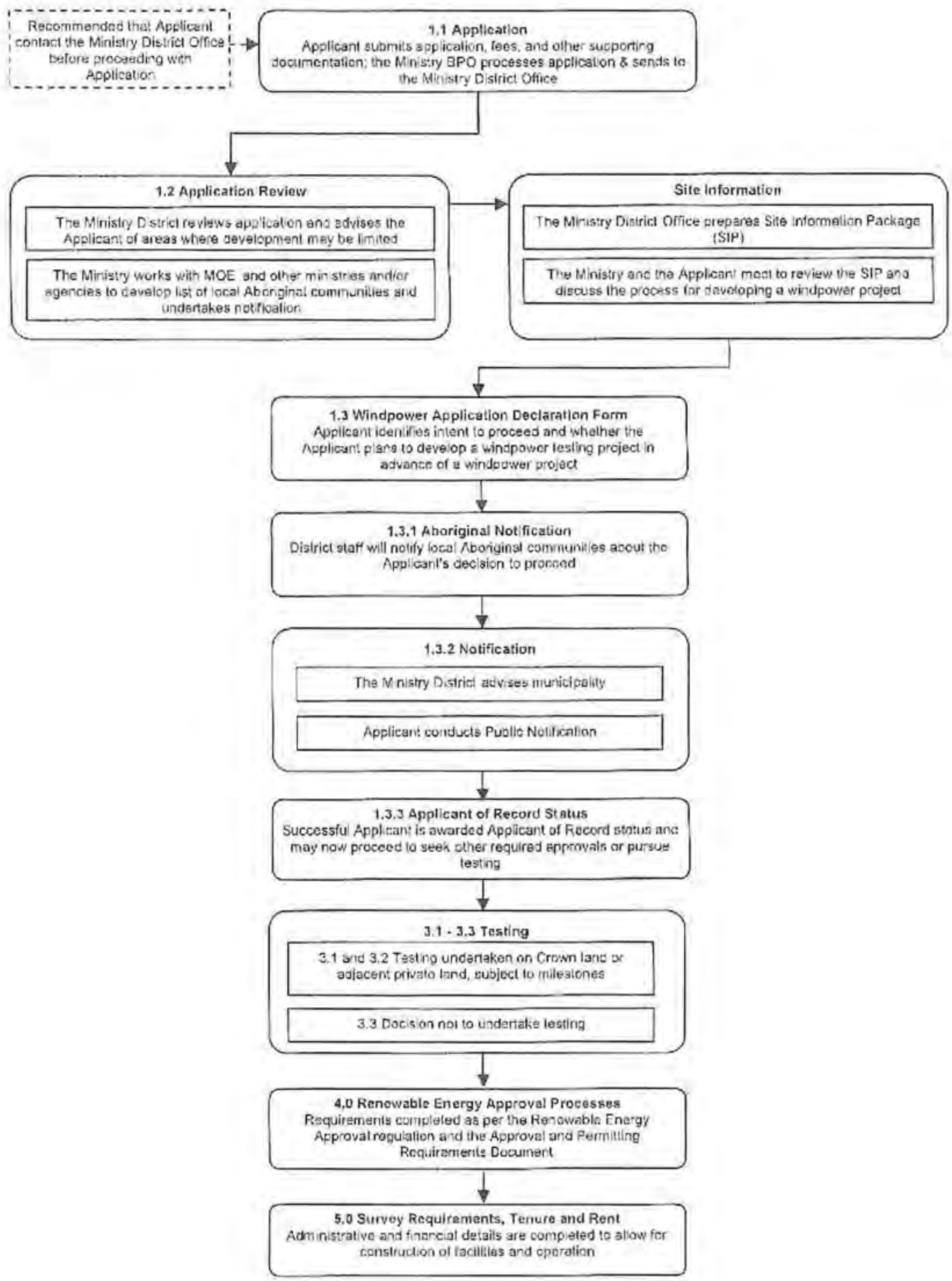
Exhibit G

FIT Contract Deadlines and Permitting Timeline

for Trout Creek Wind Project



APPENDIX D - Windpower Application Process



The attached is **Exhibit "H"** to the Affidavit of
Thomas Schneider, sworn before me
this 25th day of May, 2011

A Commissioner, etc.

9394778.2

**KEVIN FREDRICK WENTZEL, a
Commissioner, etc., Province of Ontario,
while a Student-at-Law.
Expires April 29, 2014.**

ONTARIO POWER AUTHORITY
120 Adelaide Street West
Suite 1600
Toronto, Ontario M5H 1T1
T 416-967-7474
F 416-967-1947
www.powerauthority.on.ca

FIT CONTRACT
FORM OF FORCE MAJEURE NOTICE

SUBMIT BY E-MAIL (PDF WITH SIGNATURE) TO
FIT.Contract@powerauthority.on.ca

Pursuant to Section 10.1 of the FIT Contract, the Supplier is hereby submitting this completed Force Majeure Notice to the Buyer. Capitalized terms not defined herein have the meanings ascribed thereto in the FIT Contract.

[X] This is a new Force Majeure event, start date: NA

[ ] This is an update to existing Force Majeure No.:

[ ] This is a termination notice, termination date:

Date	April 11, 2011	
Force Majeure No.	2	
Title of Force Majeure	Delay in Clarity of Regulation Regarding Second Public Meeting	
Legal Name of Supplier	Trout Creek Wind Power Inc.	
Contract Identification #	F-000655-WIN-130-601	(the "FIT Contract")
Contract Date	April 30, 2010	
Original Milestone Date for Commercial Operation	April 30, 2013	
OPA Approved Revised Milestone Date for Commercial Operation		
Type of Force Majeure	[X] CERTIFICATE/ PERMITTING/LICENCING [ ] TRANSMISSION/DISTRIBUTION SYSTEM [ ] UNANTICIPATED MAINTENANCE /OUTAGE	[ ] ACTS OF GOD / EXTREME WEATHER [ ] LABOUR DISPUTES [ ] OTHER (SPECIFY):

1. **Description of events leading to Force Majeure** (Provide reasonably full particulars of the cause and timing of the events relating to the invoked Force Majeure. Also provide documentary evidence of the same, including, without limitation, the following: newspaper articles, correspondence, emails, notes, reports, memoranda and any other documentation relevant to establishing Force Majeure.)

Please see attached document.

2. **Effect of Force Majeure** (Provide reasonably full particulars of the effect of the Force Majeure on the Supplier's ability to fulfil its obligations under the FIT Contract. Also provide documentary evidence of the same, including, without limitation, the following: reports, policy documents, correspondence, notes, memoranda and any other documentation relevant to establishing the effect.)

3. Cost of Alternatives available to remedy or remove the Force Majeure (Provide reasonably full particulars of alternatives available to the Supplier to remedy or remove the Force Majeure, together with an estimation of related costs with respect to each alternative. Also provide documentary evidence of the same, including, without limitation, the following: written cost estimates, legal or professional opinions and reports, municipal or other government policy documentation and any other documentation relevant to establishing the cost.)

4. Commercially Reasonable Efforts (Provide reasonably full particulars of efforts, if any, undertaken or contemplated by the Supplier to remedy or remove Force Majeure. Also provide documentary evidence of the commercially reasonable efforts listed, including, without limitation, the following as applicable: meeting requests with municipal officials, notes from meetings or telephone calls, minutes of meetings, letter or email correspondence with third parties, copies of reports, policies, proposals, newspaper articles and any other documentation relevant to establishing the commercially reasonable efforts.)

AUTHORIZED SIGNATORY

The Authorized Signatory must be either a signatory of the FIT Contract, a person authorized to receive Notices, or the Company Representative, if not, a *Form of Certificate of Incumbency* (OPACM-FORM-18A/Corporation or OPACM-FORM-18B/General Partner) must be submitted with this form.

By: ____________________ Date: April 11, 2011

Name: Thomas Schneider

Title: President

Legal Name of Supplier: Trout Creek Wind Power Inc.

1. **Description of events leading to Force Majeure**

   Provide reasonably full particulars of the cause and timing of the events relating to the invoked Force Majeure. Also provide documentary evidence of the same, including, without limitation, the following: newspaper articles, correspondence, emails, notes, reports, memoranda and any other documentation relevant to establishing Force Majeure.

The Supplier entered into the FIT contract on April 30, 2010, at which time the details of the public consultation requirements for the Renewable Energy Approval (REA) process (O. Reg. 359/09) had not been fully disclosed to contract holders. At the time the contract was executed the Supplier was of the understanding that the final public meeting would be held concurrent to the Ministry of Natural Resources' (MNR) review of the Natural Heritage Assessment (O. Reg. 359/09, s. 28), and the Ministry of Tourism and Culture's (MTC) review of the Heritage Assessment (O. Reg. 359/09, s. 23(2)). Sections 16(5) and 16(6) of the Regulation address the requirements for the final public meeting and are not explicit about the requirement to have confirmation letters from both ministries prior to the meeting. The Supplier understands that this requirement was clarified at a June, 2010 meeting and subsequently became aware of this clarification through discussion with associates and ministry officials. The Supplier has not yet reached the point in the REA process where a final public meeting is imminent, however, the realization that the final public meeting must be scheduled subsequent to review of application documents by the MNR and MTC has extended the project timeline such that the Supplier's ability to meet the Milestone Date for Commercial Operation (MCOD) has been compromised. The Supplier is thus claiming Force Majeure based on future delays caused by the Government's clarification of the requirements for the final public meeting required pursuant to Ontario Regulation 359/09 that will be experienced.

2. **Effect of Force Majeure**

   Provide reasonably full particulars of the effect of the Force Majeure on the Supplier's ability to fulfill its obligations under the FIT Contract. Also provide documentary evidence of the same, including, without limitation, the following: reports, policy documents, correspondence, notes, memoranda and any other documentation relevant to establishing the effect.

For the reason that the final public meeting can only be scheduled subsequent to MNR and MTC review and the Supplier being in receipt of confirmation of these reviews, the project timeline must be extended by a period of time equal to the time required to schedule a meeting (secure a venue), make all documentation available for public review (90 days prior for municipal

stakeholders, 60+1 days prior for Aboriginal communities, 60 days for general public), and post the necessary notices in newspapers (at least 60 days prior to the meeting). As the project was already on a tight timeline this unforeseen delay in being able to schedule the final meeting would compromise the Supplier's ability to meet MCOD.

3. **Cost of Alternatives available to remedy or remove the Force Majeure**
   Provide reasonably full particulars of alternatives available to the Supplier to remedy or remove the Force Majeure, together with an estimation of related costs with respect to each alternative. Also provide documentary evidence of the same, including, without limitations, the following: written cost estimates, legal or professional opinions and reports, municipal or other government policy documentation and any other documentation relevant to establishing the cost.

No alternatives are available to remedy or remove the Force Majeure.

A negative financial impact to the supplier is expected due to loss of revenues caused by not being able to meet the MCOD.

4. **Commercially Reasonable Efforts**
   Provide reasonably full particulars of efforts, if any, undertaken or contemplated by the Supplier to remedy or remove Force Majeure. Also provide documentary evidence of the commercially reasonable efforts listed, including, without limitation, the following as applicable: meeting requests with municipal officials, notes from meetings or telephone calls, minutes of meetings, letter or email correspondence with third parties, copies of reports, policies, proposals, newspaper articles and any other documentation relevant to establishing the commercially reasonable efforts.

The Supplier cannot remedy or remove the Force Majeure as it is a result of a government decision regarding the regulatory process for renewable energy approvals.

Electricity Distribution Licence

ED-2003-0043

Hydro One Networks Inc.

Valid Until

September 28, 2024

Original signed by

____

Kirsten Walli
Board Secretary
Ontario Energy Board
Date of Issuance: September 29, 2004
Date of Last Amendment: May 18, 2011

Ontario Energy Board	Commission de l'énergie de l'Ontario
P.O. Box 2319	C.P. 2319
2300 Yonge Street	2300, rue Yonge
27th Floor	27e étage
Toronto ON M4P 1E4	Toronto ON M4P 1E4

LIST OF AMENDMENTS

Board File No.	Date of Amendment
EB-2005-0286	October 12, 2005
EB-2007-0688	November 26, 2007
EB-2007-0912	February 1, 2008
EB-2007-0916	February 27, 2008
EB-2007-0968	March 20, 2008
EB-2007-0792	April 4, 2008
EB-2007-0933	June 26, 2008
EB-2007-0917	July 25, 2008
EB-2008-0269	October 22, 2008
EB-2009-0148	June 3, 2009
EB-2009-0325	November 24, 2009
EB-2009-0325	December 14, 2009
EB-2010-0172	August 26, 2010
EB-2010-0215	November 12, 2010
EB-2010-0282	January 13, 2011
EB-2010-0229	March 7, 2011
EB-2010-0398	March 29, 2011
EB-2011-0018	April 25, 2011
EB-2011-0067	May 18, 2011

Table of Contents **Page No.**

1 Definitions

In this Licence:

"**Accounting Procedures Handbook**" means the handbook, approved by the Board which specifies the accounting records, accounting principles and accounting separation standards to be followed by the Licensee;

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

"**Affiliate Relationships Code for Electricity Distributors and Transmitters**" means the code, approved by the Board which, among other things, establishes the standards and conditions for the interaction between electricity distributors or transmitters and their respective affiliated companies;

"**Conservation and Demand Management**" and "**CDM**" means distribution activities and programs to reduce electricity consumption and peak provincial electricity demand;

"**Conservation and Demand Management Code for Electricity Distributors**" means the code approved by the Board which, among other things, establishes the rules and obligations surrounding Board approved programs to help distributors meet their CDM Targets;

"**distribution services**" means services related to the distribution of electricity and the services the Board has required distributors to carry out, including the sales of electricity to consumers under section 29 of the Act, for which a charge or rate has been established in the Rate Order;

"**Distribution System Code**" means the code approved by the Board which, among other things, establishes the obligations of the distributor with respect to the services and terms of service to be offered to customers and retailers and provides minimum, technical operating standards of distribution systems;

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

"**Licensee**" means Hydro One Networks Inc.

"**Market Rules**" means the rules made under section 32 of the Electricity Act;

"**Net Annual Peak Demand Energy Savings Target**" means the reduction in a distributor's peak electricity demand persisting at the end of the four-year period (i.e. December 31, 2014) that coincides with the provincial peak electricity demand that is associated with the implementation of CDM Programs;

"**Net Cumulative Energy Savings Target**" means the total amount of reduction in electricity consumption associated with the implementation of CDM Programs between 2011-2014;

"**OPA**" means the Ontario Power Authority;

“**Performance Standards**” means the performance targets for the distribution and connection activities of the Licensee as established by the Board in accordance with section 83 of the Act;

“**Provincial Brand**” means any mark or logo that the Province has used or is using, created or to be created by or on behalf of the Province, and which will be identified to the Board by the Ministry as a provincial mark or logo for its conservation programs;

“**Rate Order**” means an Order or Orders of the Board establishing rates the Licensee is permitted to charge;

“**regulation**” means a regulation made under the Act or the Electricity Act;

“**Retail Settlement Code**” means the code approved by the Board which, among other things, establishes a distributor’s obligations and responsibilities associated with financial settlement among retailers and consumers and provides for tracking and facilitating consumer transfers among competitive retailers;

“**service area**” with respect to a distributor, means the area in which the distributor is authorized by its licence to distribute electricity;

“**Standard Supply Service Code**” means the code approved by the Board which, among other things, establishes the minimum conditions that a distributor must meet in carrying out its obligations to sell electricity under section 29 of the Electricity Act;

“**wholesaler**” means a person that purchases electricity or ancillary services in the IESO administered markets or directly from a generator or, a person who sells electricity or ancillary services through the IESO-administered markets or directly to another person other than a consumer.

2 Interpretation

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

3 Authorization

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

a) to own and operate a distribution system in the service area described in Schedule 1 of this Licence;

b) to retail electricity for the purposes of fulfilling its obligation under section 29 of the Electricity Act in the manner specified in Schedule 2 of this Licence; and

c) to act as a wholesaler for the purposes of fulfilling its obligations under the Retail Settlement Code or under section 29 of the Electricity Act.

4 Obligation to Comply with Legislation, Regulations and Market Rules

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

4.2 The Licensee shall comply with all applicable Market Rules.

5 Obligation to Comply with Codes

5.1 The Licensee shall at all times comply with the following Codes (collectively the “Codes”) approved by the Board, except where the Licensee has been specifically exempted from such compliance by the Board. Any exemptions granted to the Licensee are set out in Schedule 3 of this Licence. The following Codes apply to this Licence:

a) the Affiliate Relationships Code for Electricity Distributors and Transmitters;

b) the Distribution System Code;

c) the Retail Settlement Code; and

d) the Standard Supply Service Code.

5.2 The Licensee shall:

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

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

6 Obligation to Provide Non-discriminatory Access

6.1 The Licensee shall, upon the request of a consumer, generator or retailer, provide such consumer, generator or retailer with access to the Licensee’s distribution system and shall convey electricity on behalf of such consumer, generator or retailer in accordance with the terms of this Licence.

7 Obligation to Connect

7.1 The Licensee shall connect a building to its distribution system if:

a) the building lies along any of the lines of the distributor’s distribution system; and

b) the owner, occupant or other person in charge of the building requests the connection in writing.

7.2 The Licensee shall make an offer to connect a building to its distribution system if:

a) the building is within the Licensee's service area as described in Schedule 1; and

b) the owner, occupant or other person in charge of the building requests the connection in writing.

7.3 The terms of such connection or offer to connect shall be fair and reasonable and made in accordance with the Distribution System Code, and the Licensee's Rate Order as approved by the Board.

7.4 The Licensee shall not refuse to connect or refuse to make an offer to connect unless it is permitted to do so by the Act or a regulation or any Codes to which the Licensee is obligated to comply with as a condition of this Licence.

8 Obligation to Sell Electricity

8.1 The Licensee shall fulfill its obligation under section 29 of the Electricity Act to sell electricity in accordance with the requirements established in the Standard Supply Service Code, the Retail Settlement Code and the Licensee's Rate Order as approved by the Board.

9 Obligation to Maintain System Integrity

9.1 The Licensee shall maintain its distribution system in accordance with the standards established in the Distribution System Code and Market Rules, and have regard to any other recognized industry operating or planning standards adopted by the Board.

10 Market Power Mitigation Rebates

10.1 The Licensee shall comply with the pass through of Ontario Power Generation rebate conditions set out in Appendix A of this Licence.

11 Distribution Rates

11.1 The Licensee shall not charge for connection to the distribution system, the distribution of electricity or the retailing of electricity to meet its obligation under section 29 of the Electricity Act except in accordance with a Rate Order of the Board.

12 Separation of Business Activities

12.1 The Licensee shall keep financial records associated with distributing electricity separate from its financial records associated with transmitting electricity or other activities in accordance with the Accounting Procedures Handbook and as otherwise required by the Board.

13 Expansion of Distribution System

13.1 The Licensee shall not construct, expand or reinforce an electricity distribution system or make an interconnection except in accordance with the Act and Regulations, the Distribution System Code and applicable provisions of the Market Rules.

13.2 In order to ensure and maintain system integrity or reliable and adequate capacity and supply of electricity, the Board may order the Licensee to expand or reinforce its distribution system in accordance with Market Rules and the Distribution System Code, or in such a manner as the Board may determine.

14 Provision of Information to the Board

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

14.2 Without limiting the generality of paragraph 14.1, the Licensee shall notify the Board of any material change in circumstances that adversely affects or is likely to adversely affect the business, operations or assets of the Licensee as soon as practicable, but in any event no more than twenty (20) days past the date upon which such change occurs.

14.3 The Licensee shall:

a) immediately notify the Board in writing of the notice; and

b) provide a plan to the Board as soon as possible, but no later than ten (10) days after the receipt of the notice, as to how the affected distribution services will be maintained in compliance with the terms of this Licence.

15 Restrictions on Provision of Information

15.1 The Licensee shall not use information regarding a consumer, retailer, wholesaler or generator obtained for one purpose for any other purpose without the written consent of the consumer, retailer, wholesaler or generator.

15.2 The Licensee shall not disclose information regarding a consumer, retailer, wholesaler or generator to any other party without the written consent of the consumer, retailer, wholesaler or generator, except where such information is required to be disclosed:

a) to comply with any legislative or regulatory requirements, including the conditions of this Licence;

b) for billing, settlement or market operations purposes;

c) for law enforcement purposes; or

d) to a debt collection agency for the processing of past due accounts of the consumer, retailer, wholesaler or generator.

15.3 The Licensee may disclose information regarding consumers, retailers, wholesalers or generators where the information has been sufficiently aggregated such that their particular information cannot reasonably be identified.

15.4 The Licensee shall inform consumers, retailers, wholesalers and generators of the conditions under which their information may be released to a third party without their consent.

15.5 If the Licensee discloses information under this section, the Licensee shall ensure that the information provided will not be used for any other purpose except the purpose for which it was disclosed.

16 Customer Complaint and Dispute Resolution

16.1 The Licensee shall:

a) have a process for resolving disputes with customers that deals with disputes in a fair, reasonable and timely manner;

b) publish information which will make its customers aware of and help them to use its dispute resolution process;

c) make a copy of the dispute resolution process available for inspection by members of the public at each of the Licensee's premises during normal business hours;

d) give or send free of charge a copy of the process to any person who reasonably requests it; and

e) subscribe to and refer unresolved complaints to an independent third party complaints resolution service provider selected by the Board. This condition will become effective on a date to be determined by the Board. The Board will provide reasonable notice to the Licensee of the date this condition becomes effective.

17 Term of Licence

17.1 This Licence shall take effect on September 29, 2004 and expire on September 28, 2024. The term of this Licence may be extended by the Board.

18 Fees and Assessments

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

19 Communication

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

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

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

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

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

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

20 Copies of the Licence

20.1 The Licensee shall:

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

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

21 Conservation and Demand Management

21.1 The Licensee shall achieve reductions in electricity consumption and reductions in peak provincial electricity demand through the delivery of CDM programs. The Licensee shall meet its 2014 Net Annual Peak Demand Savings Target of 213.660 MW, and its 2011-2014 Net Cumulative Energy Savings Target of 1,130.210 GWh (collectively the "CDM Targets"), over a four-year period beginning January 1, 2011.

21.2 The Licensee shall meet its CDM Targets through:

a) the delivery of Board approved CDM Programs delivered in the Licensee's service area ("Board-Approved CDM Programs");

b) the delivery of CDM Programs that are made available by the OPA to distributors in the Licensee's service area under contract with the OPA ("OPA-Contracted Province-Wide CDM Programs"); or

c) a combination of a) and b).

21.3 The Licensee shall make its best efforts to deliver a mix of CDM Programs to all consumer types in the Licensee's service area.

21.4 The Licensee shall comply with the rules mandated by the Board's Conservation and Demand Management Code for Electricity Distributors.

21.5 The Licensee shall utilize the common Provincial brand, once available, with all Board-Approved CDM Programs, OPA-Contracted Province-Wide Programs, and in conjunction with or co-branded with the Licensee's own brand or marks.

SCHEDULE 1 DEFINITION OF DISTRIBUTION SERVICE AREA

This Schedule specifies the area in which the Licensee is authorized to distribute and sell electricity in accordance with paragraph 8.1 of this Licence.

1. Municipalities as set out in Appendix B – Tab 1.

2. First Nation Reserves as set out in Appendix B – Tab 2.

3. Unorganized Townships as set out in Appendix B – Tab 3.

4. Municipalities in which a portion of the municipality is served by the Licensee and another portion of the municipality is served by another distributor. as set out in Appendix B – Tab 4.

5. Consumers embedded within another distributor but served by the Licensee as set out in Appendix B – Tab 5.

SCHEDULE 2 PROVISION OF STANDARD SUPPLY SERVICE

This Schedule specifies the manner in which the Licensee is authorized to retail electricity for the purposes of fulfilling its obligation under section 29 of the Electricity Act.

1. The Licensee is authorized to retail electricity directly to consumers within its service area in accordance with paragraph 8.1 of this Licence, any applicable exemptions to this Licence, and at the rates set out in the Rate Orders.

SCHEDULE 3 LIST OF CODE EXEMPTIONS

This Schedule specifies any specific Code requirements from which the Licensee has been exempted.

1. The Licensee is exempt from the provisions of the Standard Supply Service Code for Electricity Distributors requiring time-of-use pricing for RPP consumers with eligible time-of-use meters, as of the mandatory date. This exemption applies only for service to approximately 150,000 very rural customers who, as of January 1, 2011, are outside the reach of the Licensee's smart meter telecommunications infrastructure. This exemption expires December 31, 2012.

2. The Licensee is exempt from the requirement of section 6.2.4.1e(i) of the Distribution System Code with respect to the following 12 generation projects, as per the Board's Decision and Order in EB-2010-0229:

Project ID	Generator Name	Project Name
11,690	Grand Valley Wind Farms Inc.	Grand Valley Wind Farms (Phase 2)
11,700	Invenergy Wind Centre ULC	Conestogo Wind Centre 2
11,720	Conestogo Wind, LP	Conestogo Wind Centre
11,870	International Power Canada, Inc.	Plateau I and II Wind
12,270	Pukwis Wind Partner Inc. & Pukwis Energy Co-op	Pukwis Community Wind Park
12,290	Glead Power Corporation	22.5 MW Ostrander Wind Farm
12,430	Grey Highlands Clean Energy LP	Grey Highlands Clean Energy
12,610	ZEP Wind Farm Ganaraska LP	ZEP Wind Farm Ganaraska
12,750	Clean Breeze Wind Park LP	Clean Breeze Wind Park
12,800	Southbranch Wind Farm Inc.	Southbranch Wind Farm
12,810	WPD Canada Corporation	Sumac Ridge Wind Farm
12,860	WPD Canada Corporation	Fairview Wind Farm

3. As per the Board's Decision and Order in EB-2011-0067, for generation facilities for which the primary energy source is water with a capacity not exceeding 10 megawatts and that are located on provincial Crown or federally-regulated lands and for which the electrical connection is to the distribution system owned by Hydro One Networks Inc. ("Hydro One"), Hydro One shall be exempted from the current connection cost deposit stipulated in s. 6.2.18(a) of the Distribution System Code (the"DSC") and shall, instead, adhere to the following schedule:

   (a) $20,000 per MW of capacity shall be paid by the proponent to Hydro One upon the execution of the Connection Cost Agreement.

   (b) An additional deposit in the amount of 30% of the total estimated cost, as estimated by Hydro One, less the amount received by Hydro One under paragraph (a) above, shall be paid by the proponent to Hydro One no later than 6 months after the proponent notifies Hydro One that it has issued its statement of completion under the earlier of the Waterpower Class Environmental Assessment and the equivalent environmental assessment process under the Canadian Environmental Assessment Act.

   (c) No later than 180 days after Hydro One receives payment of the amount referenced in paragraph (b) above, Hydro One shall provide to the proponent a construction schedule and a more accurate estimate of the project cost, if such estimate is requested and paid for by the proponent. The payment for the estimate shall be drawn from the deposit to the extent possible.

(d) The balance of the total estimated cost, as estimated by Hydro One based upon the best available information, shall be paid by the proponent to Hydro One no later than 30 days after the proponent notifies Hydro One that it has received the last of its necessary construction approval permits under Ontario's Lakes and Rivers Improvement Act or the Dominion Water Power Act.

(e) Hydro One and the proponent shall mutually agree upon an in-service date that is no later than 2 years after Hydro One receives the balance referenced in paragraph (d), above, subject to the following: in cases where a transmission upgrade or new transmission facilities are required, Hydro One and the proponent may agree to an in-service date that is later than two years after Hydro One receives the balance referenced in paragraph (d), above.

(f) The Expansion Deposit, as stipulated by Section 3.2.20 of the DSC, shall be paid to Hydro One at the same time as the payment in paragraph (d).

Notwithstanding the foregoing, if at any time the above-noted payments to Hydro One are insufficient to cover Hydro One's costs as estimated by Hydro One, the proponent shall pay, to Hydro One, additional funding sufficient to meet the shortfall identified by Hydro One, and Hydro One shall be relieved of its obligation to perform such further work until it receives the said additional funding.

SCHEDULE 4 LIST OF RRR EXEMPTIONS

The Licensee is exempt from the following sections of the Electricity Reporting and Record Keeping Requirements:

1. Section 2.1.5.5 (b)

APPENDIX A

MARKET POWER MITIGATION REBATES

1. Definitions and Interpretations

In this Licence

"embedded distributor" means a distributor who is not a market participant and to whom a host distributor distributes electricity;

"embedded generator" means a generator who is not a market participant and whose generation facility is connected to a distribution system of a distributor, but does not include a generator who consumes more electricity than it generates;

"host distributor" means a distributor who is a market participant and who distributes electricity to another distributor who is not a market participant.

In this Licence, a reference to the payment of a rebate amount by the IESO includes interim payments made by the IESO.

2. Information Given to IESO

a Prior to the payment of a rebate amount by the IESO to a distributor, the distributor shall provide the IESO, in the form specified by the IESO and before the expiry of the period specified by the IESO, with information in respect of the volumes of electricity withdrawn by the distributor from the IESO-controlled grid during the rebate period and distributed by the distributor in the distributor's service area to:

i consumers served by a retailer where a service transaction request as defined in the Retail Settlement Code has been implemented; and

ii consumers other than consumers referred to in clause (i) who are not receiving the fixed price under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998.*

b Prior to the payment of a rebate amount by the IESO to a distributor which relates to electricity consumed in the service area of an embedded distributor, the embedded distributor shall provide the host distributor, in the form specified by the IESO and before the expiry of the period specified in the Retail Settlement Code, with the volumes of electricity distributed during the rebate period by the embedded distributor's host distributor to the embedded distributor net of any electricity distributed to the embedded distributor which is attributable to embedded generation and distributed by the embedded distributor in the embedded distributor's service area to:

i consumers served by a retailer where a service transaction request as defined in the Retail Settlement Code has been implemented; and

ii consumers other than consumers referred to in clause (i) who are not receiving the fixed price under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998*.

c Prior to the payment of a rebate amount by the IESO to a distributor which relates to electricity consumed in the service area of an embedded distributor, the host distributor shall provide the IESO, in the form specified by the IESO and before the expiry of the period specified by the IESO, with the information provided to the host distributor by the embedded distributor in accordance with section 2.

The IESO may issue instructions or directions providing for any information to be given under this section. The IESO shall rely on the information provided to it by distributors and there shall be no opportunity to correct any such information or provide any additional information and all amounts paid shall be final and binding and not subject to any adjustment.

For the purposes of attributing electricity distributed to an embedded distributor to embedded generation, the volume of electricity distributed by a host distributor to an embedded distributor shall be deemed to consist of electricity withdrawn from the IESO-controlled grid or supplied to the host distributor by an embedded generator in the same proportion as the total volume of electricity withdrawn from the IESO-controlled grid by the distributor in the rebate period bears to the total volume of electricity supplied to the distributor by embedded generators during the rebate period.

3. Pass Through of Rebate

A distributor shall promptly pass through, with the next regular bill or settlement statement after the rebate amount is received, any rebate received from the IESO, together with interest at the Prime Rate, calculated and accrued daily, on such amount from the date of receipt, to:

a retailers who serve one or more consumers in the distributor’s service area where a service transaction request as defined in the Retail Settlement Code has been implemented;

b consumers who are not receiving the fixed price under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998* and who are not served by a retailer where a service transaction request as defined in the Retail Settlement Code has been implemented; and

c embedded distributors to whom the distributor distributes electricity.

The amounts paid out to the recipients listed above shall be based on energy consumed and calculated in accordance with the rules set out in the Retail Settlement Code. These payments may be made by way of set off at the option of the distributor.

If requested in writing by OPGI, the distributor shall ensure that all rebates are identified as coming from OPGI in the following form on or with each applicable bill or settlement statement:

“ONTARIO POWER GENERATION INC. rebate”

Any rebate amount which cannot be distributed as provided above or which is returned by a retailer to the distributor in accordance with its licence shall be promptly returned to the host distributor or IESO as applicable, together with interest at the Prime Rate, calculated and accrued daily, on such amount from the date of receipt.
Nothing shall preclude an agreement whereby a consumer assigns the benefit of a rebate payment to a retailer or another party.

Pending pass-through or return to the IESO of any rebate received, the distributor shall hold the funds received in trust for the beneficiaries thereof in a segregated account.

ONTARIO POWER GENERATION INC. REBATES

For the payments that relate to the period from May 1, 2006 to April 30, 2009, the rules set out below shall apply.

1. Definitions and Interpretations

In this Licence

"embedded distributor" means a distributor who is not a market participant and to whom a host distributor distributes electricity;

"embedded generator" means a generator who is not a market participant and whose generation facility is connected to a distribution system of a distributor, but does not include a generator who consumes more electricity than it generates;

"host distributor" means a distributor who is a market participant and who distributes electricity to another distributor who is not a market participant.

In this Licence, a reference to the payment of a rebate amount by the IESO includes interim payments made by the IESO.

2. Information Given to IESO

a Prior to the payment of a rebate amount by the IESO to a distributor, the distributor shall provide the IESO, in the form specified by the IESO and before the expiry of the period specified by the IESO, with information in respect of the volumes of electricity withdrawn by the distributor from the IESO-controlled grid during the rebate period and distributed by the distributor in the distributor's service area to:

i consumers served by a retailer where a service transaction request as defined in the Retail Settlement Code has been implemented and the consumer is not receiving the prices established under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998*; and

ii consumers other than consumers referred to in clause (i) who are not receiving the fixed price under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998*.

b Prior to the payment of a rebate amount by the IESO to a distributor which relates to electricity consumed in the service area of an embedded distributor, the embedded distributor shall provide the host distributor, in the form specified by the IESO and before the expiry of the period specified in the Retail Settlement Code, with the volumes of electricity distributed during the rebate period by the embedded distributor's host distributor to the embedded distributor net of any electricity distributed to the embedded distributor which is attributable to embedded generation and distributed by the embedded distributor in the embedded distributor's service area to:

i consumers served by a retailer where a service transaction request as defined in the Retail Settlement Code has been implemented; and ii consumers other than consumers referred to in clause (i) who are not receiving the fixed price under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998*.

c Prior to the payment of a rebate amount by the IESO to a distributor which relates to electricity consumed in the service area of an embedded distributor, the host distributor shall provide the IESO, in the form specified by the IESO and before the expiry of the period specified by the IESO, with the information provided to the host distributor by the embedded distributor in accordance with section 2.

The IESO may issue instructions or directions providing for any information to be given under this section. The IESO shall rely on the information provided to it by distributors and there shall be no opportunity to correct any such information or provide any additional information and all amounts paid shall be final and binding and not subject to any adjustment.

For the purposes of attributing electricity distributed to an embedded distributor to embedded generation, the volume of electricity distributed by a host distributor to an embedded distributor shall be deemed to consist of electricity withdrawn from the IESO-controlled grid or supplied to the host distributor by an embedded generator in the same proportion as the total volume of electricity withdrawn from the IESO-controlled grid by the distributor in the rebate period bears to the total volume of electricity supplied to the distributor by embedded generators during the rebate period.

3. Pass Through of Rebate

A distributor shall promptly pass through, with the next regular bill or settlement statement after the rebate amount is received, any rebate received from the IESO, together with interest at the Prime Rate, calculated and accrued daily, on such amount from the date of receipt, to:

a retailers who serve one or more consumers in the distributor’s service area where a service transaction request as defined in the Retail Settlement Code has been implemented and the consumer is not receiving the prices established under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998*;

b consumers who are not receiving the fixed price under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998* and who are not served by a retailer where a service transaction request as defined in the Retail Settlement Code has been implemented; and

c embedded distributors to whom the distributor distributes electricity.

The amounts paid out to the recipients listed above shall be based on energy consumed and calculated in accordance with the rules set out in the Retail Settlement Code. These payments may be made by way of set off at the option of the distributor.
If requested in writing by OPGI, the distributor shall ensure that all rebates are identified as coming from OPGI in the following form on or with each applicable bill or settlement statement:

“ONTARIO POWER GENERATION INC. rebate”

Any rebate amount which cannot be distributed as provided above or which is returned by a retailer to the distributor in accordance with its licence shall be promptly returned to the host distributor or IESO as applicable, together with interest at the Prime Rate, calculated and accrued daily, on such amount from the date of receipt.

Nothing shall preclude an agreement whereby a consumer assigns the benefit of a rebate payment to a retailer or another party.

Pending pass-through or return to the IESO of any rebate received, the distributor shall hold the funds received in trust for the beneficiaries thereof in a segregated account.

APPENDIX B

TAB 1 MUNICIPALITIES

Name of Municipality:	Township of Addington Highlands
Formerly Known as:	Township of Denbign, Abinger and Ashby, Township of Anglesea and Effingham, Kaladar, as at December 31. 1999.
Name of Municipality:	Township of Adelaide Metcalfe
Formerly Known As:	Township of Adelaide, Township of Metcalfe, as at December 31, 2000.
Name of Municipality:	Township of Adjala-Tosorontio
Formerly Known As:	Portions of the Township of Adjala, Township of Tosorontio, Township of Sunnidale, as at December 31, 1993.
Name of Municipality:	Township of Admaston/Bromley
Formerly Known As:	Township of Admaston, Township of Bromley, as at December 31, 1999.
Name of Municipality:	Township of Alberton as at March 31, 1999.
Formerly Known As:	Same
Name of Municipality:	Township of Algonquin Highlands, (Formerly known as Township of Sherborne, Stanhope, McClintock, Livingstone, Lawrence and Nightingale)
Formerly Known As:	Township of Sherborne et al,Township of Stanhope, as at December 31, 2000.
Name of Municipality:	Township of Alnwick/Haldimand
Formerly Known As:	Township of Alnwick, Township of Haldimand, as at December 31, 2000.
Name of Municipality:	Township of Amaranth as at March 31, 1999.
Formerly Known As:	Same

Name of Municipality: Township of The Archipelago as at March 31, 1999.
Formerly Known As: Conger, Cowper, Harrison, Henvey, Wallbridge plus geographic/unorganized townships and unsurveyed areas

Name of Municipality: Township of Armour as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Armstrong as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Town of Arnprior as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Municipality of Arran-Elderslie
Formerly Known As: Township of Arran, Township of Elderslie, Town of Chesley, Village of Tara, Village of Paisley, as at December 31, 1998.

Name of Municipality: Township of Ashfield-Colborne-Wawanosh
Formerly Known As: Township of Ashfield, Township of West Wananosh,
Township of Colborne, as at December 31, 2000.

Name of Municipality: Township of Assiginack as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Athens
Formerly Known As: Township of Rear of Young and Escott,
Village of Athens, as at December 31, 2000.

Name of Municipality: Township of Augusta as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Baldwin as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Town of Bancroft

Formerly Known As: Town of Bancroft, Township of Dungannon, as at December 31, 1998.

Name of Municipality: Township of Barrie Island as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Municipality of Bayham
Formerly Known As: Township of Baymen, Village of Port Burwell, Village of Vienna, as at December 31, 1997.

Name of Municipality: Township of Beckwith as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Billings as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Black River-Matheson as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Blandford-Blenheim as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Town of Blind River as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Bonfield as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Bonnechere Valley
Formerly Known As: Village of Eganville, Township of Grattan, Township of Sebastopol, Township of South Algona, as at December 31, 2000.

Name of Municipality: Township of Brethour as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Municipality of Brighton

Formerly Known As: Town of Brighton, Township of Brighton, as at December 31, 2001.

Name of Municipality: City of Brockville as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Brudenell, Lyndoch and Raglan
Formerly Known As: Township of Brudenell and Lyndoch, Township of Raglan, as at December 31, 1998.

Name of Municipality: Township of Burpee and Mills
Formerly Known As: Township of Burpee, Unorganized Twp of Mills, as at December 31, 1997.

Name of Municipality: Town of Caledon
Formerly Known As: Township of Albion, Township of Caledon, Village of Bolton, Village of Caledon East, Township of Chinguacousy (part), as at December 31, 1973.

Name of Municipality: Township of Calvin as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Town of Carleton Place as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Carling as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Carlow/Mayo
Formerly Known As: Township of Carlow, Township of Mayo, as at December 31, 2000.

Name of Municipality: Township of Casey as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Cavan-Millbrook-North Monoghan
Formerly Known As: Township of Cavan, Township of North Monaghan, Village of Millbrook, as at December 31, 1997.

Name of Municipality: Township of Central Frontenac
Formerly Known As: Township of Hinchinbrooke, Township of Kennebec, Township of Olden, Township of Oso, as at December 31, 1997.

Name of Municipality: Township of Central Manitoulin
Formerly Known As: Twp. Of Carnarvon, Unorganized Twp of Sandfield, as at April 30, 1997.

Name of Municipality: Municipality of Centre Hastings
Formerly Known As: Village of Madoc, Township of Huntingdon, as at December 31, 1997.

Name of Municipality: Township of Chamberlain as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Champlain
Formerly Known As: Village of L'Orignal, Township of West Hawkesbury, Township of Longueuil, Town of Vankleek Hill, as at December 31, 1997.

Name of Municipality: Township of Chapple as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Municipality of Charlton and Dack
Formerly Known As: Town of Charlton, Township of Dack, as at December 31, 2002.

Name of Municipality: Township of Chatsworth
Formerly Known As: Village of Chatsworth, Township of Holland, Township of Sullivan, as at December 31, 1999.

Name of Municipality: Township of Chisolm as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: City of Clarence-Rockland

Formerly Known As:	Town of Rockland, Township of Clarence, as at December 31, 1997.
Name of Municipality:	Town of Cobalt as at March 31, 1999.
Formerly Known As:	Same
Name of Municipality:	Township of Cockburn Island as at March 31, 1999
Formerly Known As:	Same
Name of Municipality:	Township of Coleman as at March 31, 1999.
Formerly Known As:	Same
Name of Municipality:	Township of Conmee as at March 31, 1999.
Formerly Known As:	Same
Name of Municipality:	Township of Dawn-Euphemia
Formerly Known As:	Township of Dawn, Township of Euphemia, as at December 31, 1997.
Name of Municipality:	Township of Dawson
Formerly Known As:	Township of Atwood, Township of Blue, Township of Worthington, Township of Dilke, as at December 31, 1996.
Name of Municipality:	Town of Deep River as at March 31, 1999.
Formerly Known As:	Same
Name of Municipality:	Town of Deseronto as at March 31, 1999.
Formerly Known As:	Same
Name of Municipality:	Township of Dorion as at March 31, 1999.
Formerly Known As:	Same
Name of Municipality:	Township of Douro-Dummer
Formerly Known As:	Township of Douro, Township of Dummer, as at December 31, 1997.
Name of Municipality:	Township of Drummond/North Elmsley

Formerly Known As:	Township of Drummond, Township of North Elmsley, as at December 31, 1997.
Name of Municipality:	City of Dryden
Formerly Known As:	Town of Dryden, Township of Barclay
Name of Municipality:	Township of Dysart et al as at March 31, 1999.
Formerly Known As:	Same
Name of Municipality:	Municipality of Ear Falls as at March 31, 1999.
Formerly Known As:	Same
Name of Municipality:	Township of East Ferris as at March 31, 1999.
Formerly Known As:	Same
Name of Municipality:	Township of East Garafraxa as at March 31, 1999.
Formerly Known As:	Same
Name of Municipality:	Township of East Hawkesbury as at March 31, 1999.
Formerly Known As:	Same
Name of Municipality:	Township of Elizabethtown-Kitley
Formerly Known As:	Township of Kitley, Township of Elizabethtown as at December 31, 2000.
Name of Municipality:	City of Elliott Lake as at March 31, 1999.
Formerly Known As:	Same
Name of Municipality:	Township of Emo, as at March 31, 1999.
Formerly Known As:	Same
Name of Municipality:	Township of Englehart as at March 31, 1999.
Formerly Known As:	Same
Name of Municipality:	Township of Enniskillen as at March 31, 1999.
Formerly Known As:	Same

Name of Municipality: Town of Erin
Formerly Known As: Township of Erin, Village of Erin, as at December 31, 1997.

Name of Municipality: Township of Evantural as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Faraday as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Fauquier-Strickland as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Municipality of French River
Formerly Known As: Township of Cosby, Township of Mason, Township of Martland, geographic/unorganized townships of Delamere, Hoskin and Scollard in whole and Bigwood, Cherriman and Haddo in part, as at December 31, 1998.

Name of Municipality: Township of Front of Yonge as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Frontenac Islands
Formerly Known As: Township of Howe Island, Township of Wolfe Island, as at December 31, 1997.

Name of Municipality: Township of Galway-Cavendish and Harvey
Formerly Known As: Township of Galway and Cavandish, Township of Harvey, as at December 31, 1997.

Name of Municipality: Township of Gauthier as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Georgian Bay as at March 31, 1999.
Formerly Known As: Township of Freeman, Township of Gibson, Township of Baxter.

Name of Municipality: Township of Georgian Bluffs
Formerly Known As: Township of Derby, Township of Keppel, Township of Sarawak, as at December 31, 2000.

Name of Municipality: Town of Georgina as at March 31, 1999.
Formerly Known As: Township of North Gwillimbury, Township of Georgina.

Name of Municipality: Township of Gillies as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Gordon as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Town of Gore Bay as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Greater Madawaska
Formerly Known As: Township of Bagot, Blythfield and Brougham, Township of Griffith, and Matawatchan, (Jan 1998: Township of Bagot and Blythfield, Township of Brougham amalgamated into Township of Bagot, Blythfield and Brougham), as at December 31, 2000.

Name of Municipality: Town of Greater Napanee
Formerly Known As: Township of Adolphustown, Township of North Fredericksburgh, Township of South Fredericksburgh, Township of Richmond, Town of Napanee, as at December 31, 1997.

Name of Municipality: Municipality of Greenstone
Formerly Known As: Town of Geraldton, Town of Longlac, Township of Beardmore, Township of Nakina, as at December 31, 2000.

Name of Municipality: Municipality of Grey Highlands

Formerly Known As: Township of Artemesia, Township of Euphrasia
Village of Markdale, Township of Osprey, as at December 31, 2000.

Name of Municipality: Township of Hamilton as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Harley as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Harris as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Municipality of Hastings Highlands
Formerly Known As: Township of Bangor, Wicklow and McClure, Township of Herschel, Township of Monteagle, as at December 31, 2000.

Name of Municipality: Township of Havelock-Belmont-Methuen
Formerly Known As: Township of Belmont and Methuen, Village of Havelock, as at December 31, 1997.

Name of Municipality: Township of Head, Clara and Maria, as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Municipality of Highland East
Formerly Known As: Township of Bicroft, Township Cardiff, Township of Glamorgan, Township of Monmouth, as at December 31, 2000.

Name of Municipality: Township of Hilliard as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Hornpayne as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Horton as at March 31, 1999.
Formerly Known As: Same

Name of Municipality:	The Township of Howick as at March 31, 1999.
Formerly Known As:	Same
Name of Municipality:	Township of Hudson as at March 31, 1999.
Formerly Known As:	Same
Name of Municipality:	Township of Ignace as at March 31, 1999.
Formerly Known As:	Same
Name of Municipality:	Township of James as at March 31, 1999.
Formerly Known As:	Same
Name of Municipality:	Township of Joly as at March 31, 1999.
Formerly Known As:	Same
Name of Municipality:	The City of Kawartha Lakes
Formerly Known As:	County of Victoria, Town of Lindsay, Municipality of Bobcaygeon/ Verulam, Village of Fenelon Falls, Village of Omemee, Village of Sturgeon Point, Village of Woodville, Township of Bexley, Township of Carden/Dalton, Township of Eldon, Township of Emily, Township of Fenelon, Township of Laxton, Digby and Longford, Township Manvers, Township of Mariposa, Township of Ops, Township of Somerville, (Jan 2000: Township of Carden , Township of Dalton amalgamated into Township of Carden/Dalton), (Jan 2000; Village of Bobcaygeon/Township of Verulam amalgamated into the Municipality of Bobcaygeon/Verulam), as at December 31, 2000.
Name of Municipality:	Town of Kearney as at March 31, 1999.
Formerly Known As:	Same

Name of Municipality: Township of Kerns as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Municipality of Killarney
Formerly Known As: Townships of Rutherford and George Island and the geographic/unorganized townships of, Allen, Atlee, Goschen, Hansen, Killarney, Kilpatrick, Sale, Struthers, Travers, and portions of the geographic/unorganized townships of Bigwood, Carlyle, Humboldt, Mowat, and unsurveyed territory and islands, as at Deember 31, 1998.

Name of Municipality: Town of Kirkland Lake as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of La Vallee as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Lake of Bays as at March 31, 1999.
Formerly Known As: Township of McLean, Township of Ridout, Township of Franklin, Township of Sinclair, Township of Finlayson.

Name of Municipality: Township of Lake of the Woods
Formerly Known As: Township of McCrosson and Tovell, Township of of Morson, unorganized islands in Kenora District and Rainy River District, as at December 31, 1998.

Name of Municipality: Municipality of Lambton Shores
Formerly Known As: Village of Arkona, Town of Bosanquet, Town of Forest, Village of Grand Bend, Village of Thedford, as at December 31, 2000.

Name of Municipality: Township of Lanark Highlands
Formerly Known As: Township of Darling, Township of North West Lanark, (May 1997: Lavant, Dalhousie and North Sherbrook Township/Township Lanark/Village Lanark amalgamated into Township of North West Lanark), as at June 30, 1996.

Name of Municipality: Township of Larder Lake as at March 31, 1999.

Formerly Known As: Same

Name of Municipality: Town of Latchford as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Town of Laurentian Hills
Formerly Known As: Township of Rolph, Township of Wylie and McKay, Village of Chalk River, as at December 31, 1999.

Name of Municipality: Township of Laurentian Valley
Formerly Known As: Township of Stafford and Pembroke, Township of Alice and Fraser, as at December 31, 1999.

Name of Municipality: Township of Limerick as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Loyalist
Formerly Known As: Township of Amherst Island, Township of Ernestown, Village of Bath, as at December 31, 1997.

Name of Municipality: Township of Lucan Biddulph
Formerly Known As: Village of Lucan, Township of Biddulph, Police Village of Granton, as at December 31, 1998.

Name of Municipality: Township of Machar as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Machin as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Madawaska Valley
Formerly Known As: Village of Barry's Bay, Township of Radcliffe, Township of Sherwood, Jones and Burns, as at December 31, 2000.

Name of Municipality: Township of Madoc as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Malahide
Formerly Known As: Township of Malahide, Township of Dorchester, Village of Springfield, as at December 31, 1997.

Name of Municipality: Township of Manitouwadge as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Mapleton
Formerly Known As: Township of Mapleton, Township of Maryborough, (Jan 1998-Village of Drayton, Township of Peel amalgamated into the Township of Mapleton), as at December 31, 1998.

Name of Municipality: Town of Marathon as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Municipality of Markstay-Warren
Formerly Known As: Township of Hagar, Township of Ratter and Dunnet, geographic/unorganized township of Awrey and portions of the geographic/unorganized townships of Hawley, Henry, Loughrin, Street, as at December 31, 1998.

Name of Municipality: Municipality of Marmora and Lake
Formerly Known As: Township of Marmora and Lake, Village of Marmora, (Jan 1998: Village of Deloro, Township of Marmora and Lake amalgamated into the Township of Marmora and Lake, as at December 31, 1997.
Name of Municipality: Township of Matachewan as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Town of Mattawa as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Mattawan as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Mattice-Val Cote as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of McDougall
Formerly Known As: Township of McDougall, geographic/unorganized township of Ferguson, as at December 31, 1999.

Name of Municipality: Township of McGarry as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of McKellar as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of McMurrich/Monteith
Formerly Known As: Township of McMurrich, geographic/unorganized township of Monteith (eastern portion), as at December 31, 1997.

Name of Municipality: Township of McNab/Braeside
Formerly Known As: Township of McNab, Village Braeside, as at December 31, 1997

Name of Municipality: Municipality of Meaford (formerly known as Town of Georgian Highlands)
Formerly Known As: Township of St. Vincent, Township of Sydenham, Town of Meaford, as at December 31, 2000.

Name of Municipality: Township of Melancthon as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Village of Merrickville-Wolford
Formerly Known As: Township of Wolford, Village of Merrickville, as at December 31, 1997.

Name of Municipality:	Township of Middlesex Centre
Formerly Known As:	Township of Lobo, Township of London, Township of Delaware, Police Village of Delaware, as at December 31, 1998.
Name of Municipality:	Township of Minden Hills
Formerly Known As:	Township of Anson, Hindon and Minden, Township of Lutterworth, Township of Snowdon, as at December 31, 2000.
Name of Municipality :	Town of Mono as at March 31, 1999.
Formerly Known As:	Same
Name of Municipality:	Township of Montague as at March 31, 1999.
Formerly Known As:	Same
Name of Municipality:	Township of Moonbeam as at March 31, 1999.
Formerly Known As:	Same
Name of Municipality:	Town of Moosonee as at March 31, 1999.
Formerly Known As:	Moosonee Development Board
Name of Municipality:	Township of Morley
Formerly Known As:	Township of Morley, geographic/unorganized townships Twp's of Dewart and Sifton, as at December 31, 2003.
Name of Municipality:	Municipality of Morris-Turnberry
Formerly Known As:	Township of Morris, Township of Turnberry, as at December 31, 2000.
Name of Municipality:	Township of Mulmar as at March 31, 1999.
Formerly Known As:	Same
Name of Municipality:	Township of Muskoka Lakes as at March 31, 1999.
Formerly Known As:	Township of Cardwell, Township of Watt, Township of Medora, Township of Monck, Township of Wood.
Name of Municipality:	Township of Nairn and Hyman

Formerly Known As:	Township of Nairn, Unorganized Township of Hyman, as at December 31, 1997.
Name of Municipality:	The Nation Municipality
Formerly Known As:	Township of Cambridge, Township of South Plantagenet, Village of St. Isidore, Township of Caledonia, as December 31, 1997.
Name of Municipality:	Municipality of Neebing as at March 31, 1999.
Formerly Known As:	Same
Name of Municipality:	City of Temiskaming Shores
Formerly Known As:	**T**own of New Liskeard, Town of Haileybury, Township of Dymond, as at December 31, 2003.
Name of Municipality:	Township of Nipigon as at March 31, 1999.
Formerly Known As:	Same
Name of Municipality:	Township of Nipissing as at March 31, 1999.
Formerly Known As:	Same
Name of Municipality:	Township of North Algona-Wilberforce
Formerly Known As:	Township of North Algona, Township of Wilberforce, as at December 31, 1998.
Name of Municipality:	Municipality of Northern Bruce Peninsula
Formerly Known As:	Township of St. Edmunds, Township of Lindsay, Township of Eastnor, Village of Lion’s Head, as at December 31, 1998.
Name of Municipality:	Township of North Dundas
Formerly Known As:	Township of Mountain, Township of Winchester, Village of Chesterville, Village of Winchester, as at December 31, 1997.
Name of Municipality:	Township of North Frontenac
Formerly Known As:	Township of Barrie, Township of Clarendon, Township of Miller, Township of Palmerston, Township of North Canonto, Township of South Canonto, as at December 31, 1997.

Name of Municipality: Township of North Glengarry
Formerly Known As: Township of Kenyon, Township of Lochiel, Town of Alexandria, Village of Maxville, Police Village of Apple Hill, as at December 31, 1997.

Name of Municipality: Township of North Grenville
Formerly Known As: Township of Oxford-on-Rideau, Town of Kemptville, Township of South Gower, as at December 31, 1997.

Name of Municipality: Township of North Himsworth as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of North Kawartha
Formerly Known As: Township of Burleigh and Anstruther, Township of Chandos, as at December 31, 1997.

Name of Municipality: Town of North Perth
Formerly Known As: Township of Wallace, Township of Elma, Town of Listowel, as at December 31, 1997.

Name of Municipality: Township of The North Shore as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of North Stormont
Formerly Known As: Township of Finch, Township of Roxborough, Village of Finch, Police Village of Avonmore (in the Township of Roxborough), as at December 31, 1997.

Name of Municipality: Town of Northeastern Manitoulin and the Islands
Formerly Known As: Township of Howland, Town of Little Current, all islands not part of other municipalities on Manitoulin Island, as at December 31, 1997.

Name of Municipality: Township of O'Conner as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Oliver Paipoonge
Formerly Known As: Township of Oliver, Township of Paipoonge, as at December 31, 1997.

Name of Municipality: Township of Opasatika as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Oro-Medonte
Formerly Known As: Portions of the Township of Medonte, Township of Oro, Township of Orillia, Township of Tay, Township of Flos, Township of Vespra, as at December 31, 1993.

Name of Municipality: Township of Otonabee-South Monaghan
Formerly Known As: Township of Otonabee, Township of South Monaghan, as at December 1, 1999.

Name of Municipality: City of Owen Sound as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Papineau-Cameron as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Perry as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Pelee as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Perth East
Formerly Known As: Township of Mornington, Township of Ellice, Township of North Easthope, Township of South Easthope, Village of Milverton, as at December 31, 1997.

Name of Municipality: The Township of Perth South

Formerly Known As: Township of Downie, Township of Blanshard, as at December 31, 1997.

Name of Municipality: Town of Perth as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Town of Petawawa
Formerly Known As: Village of Petawawa, Township of Petawawa, as at June 30, 1996.

Name of Municipality: Township of Pickle Lake as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Town of Plympton-Wyoming
Formerly Known As: Township of Plympton, Village of Wyoming, as at December 31, 2000.

Name of Municipality: Municipality of Powassan
Formerly Known As: Town of Powassan, Township of Himsworth South, Town of Trout Creek, as at December 31, 2000.

Name of Municipality: County of Prince Edward
Formerly Known As: County of Prince Edward, Town of Picton, Village of Bloomfield, Village of Wellington, Township of Ameliasburgh, Township of Athol, Township of Hallowell, Township of Hillier, Township of North Marysburgh, Township of South Marysburgh, Township of Sophiasburgh, as at December 31, 1997.

Name of Municipality: City of Quinte West
Formerly Known As: City of Trenton, Village of Frankford, Township of Sidney, Township of Murray, as at December 31, 1997.

Name of Municipality: Town of Rainy River as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Ramara
Formerly Known As: Township of Mara, Township of Rama , as at December 31, 1993.
Name of Municipality: Township of Red Rock as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Rideau Lakes
Formerly Known As: Village of Newboro, Township of Bastard and South Burgess, Township of North Crosby, Township of South Crosby, Township of South Elmsley, as at December 31, 1997.

Name of Municipality: Township of Ryerson as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Schreiber as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Seguin
Formerly Known As: Township of Humphrey, Township of Foley, Township of Christie, geographic/unorganized Township of Monteith (western portion), Village of Rosseau, as at December 31, 1997.

Name of Municipality: Township of Severn
Formerly Known As: Portions of Village of Coldwater, Township of Matchedash, Township of Medonte, Township of Orillia, Township of Tay, as at December 31, 1993.

Name of Municipality: Township of Shedden as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Town of Shelburne as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Shuniah as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Sioux Narrows-Nestor Falls
Formerly Known As: Township of Sioux Narrows, all of the geographic/unorganized townships of Code, Devonshire, Godson, Manross, MacQuarrie, Phillips, Tweedsmuir, and Work, portions of the geographic/unorganized townships of LeMay, McKeekin in Kenora District, and the geographic/unorganized townships of Claxton, Croome, and Mathieu in the Rainy River District, as at December 31, 2000.

Name of Municipality: Separated Town of Smiths Falls as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Town of Smooth Rock Falls as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of South Algonquin
Formerly Known As: Township of Airy and geographic/unincorporated townships of Dickens, Lyell, Murchison and Sabine, as at May 31, 1997.

Name of Municipality: Town of South Bruce Peninsula
Formerly Known As: Township of Albemarle, Township of Amabel, Town of Wiarton, Village of Hepworth, as at December 31, 1998.

Name of Municipality: Township of South Frontenac
Formerly Known As: Township of Bedford, Township of Loughborough, Township of Portland, Township of Storrington, as at December 31, 1997.

Name of Municipality: Village of South River as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Municipality of Southwest Middlesex
Formerly Known As: Township of Ekfrid, Township of Mosa, Village of Glencoe, Village of Wardsville, as at December 31, 2000.

Name of Municipality: Township of Southwold as at March 31, 1999.
Formerly Known As: Same
Name of Municipality: Township of Springwater

Formerly Known As: Portions of the former Village of Elmvale, Township of Flos, Township of Medonte, Township of Vespra, Town of Wasaga Beach, as at December 31, 1993.

Name of Municipality: Municipality of St. Charles
Formerly Known As: Township of Casimir, Jennings & Appleby and the geographic/unorganized townships of Cherriman and Haddo, as at December 31, 1998.

Name of Municipality: Township of St. Clair
Formerly Known As: Township of Sombra, Township of Moore, as at December 31, 2000.

Name of Municipality: Township of Stirling-Rawdon
Formerly Known As: Village of Stirling, Township of Rawdon, as at December 31, 1997.

Name of Municipality: Township of Stone Mills
Formerly Known As: Township of Camden East, Township of Sheffield, Village of Newburgh, as at December 31, 1997.

Name of Municipality: Township of Strong as at March 31, 1996.
Formerly Known As: Same

Name of Municipality: Township of Tay Valley
Formerly Known As: Township of South Sherbrooke, Township of Bathurst, Township of North Burgess, as at December 31, 1997.

Name of Municipality: Township of Tehkummah as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Municipality of Temagami as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Terrace Bay as at March 31, 1999
Formerly Known As: Same
Name of Municipality: Municipality of Thames Centre

Formerly Known As: Township of North Dorchester, Township of West Nissouri, Village of Dorchester, Police Village of Thorndale, as at December 31, 2000.

Name of Municipality: Town of Thessalon as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Village of Thornloe as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: City of Thorold as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: City of Timmins as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Tiny as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Municipality of Trent Hills
Formerly Known As: Municipality of Campbellford/Seymour, Township of Percy, Village of Hastings, Police Village of Warkworth (Jan 1998-Town of Campbellford, Township of Seymour amalgamated into the Municipality of Campbellford/Seymour), as at December 31, 2000.

Name of Municipality: Township of Tudor and Cashel as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Municipality of Tweed
Formerly Known As: Village of Tweed, Township of Hungerford, Township of Elzevir and Gromsthorpe, as at December 31, 1997.

Name of Municipality: Township of Tyendinaga as at March 31, 1999.
Formerly Known As: Same
Name of Municipality: Township of Val Rita-Harty as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Wainfleet as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Municipality of West Elgin
Formerly Known As: Township of Aldborough, Village of West Lorne, Police Village of Rodney, as at December 31, 1997.

Name of Municipality: Town of Whitchurch-Stouffville as at March 31, 1999.
Formerly Known As: Village of Stouffville and portions of the Township of Whitchurch and the Township of Markham.

Name of Municipality: Township of White River as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Municipality of Whitestone
Formerly Known As: Township Hagerman, and the geographic/unorganized townships of Ferrie, McKenzie, East Burpee, and a portion of the Township of Magnetawan, as at December 31, 1999.

Name of Municipality: Township of Wollaston as at March 31, 1999.
Formerly Known As: Same

APPENDIX B

TAB 2 FIRST NATION RESERVES

Reserve Name: Abitibi I.R. No. 70
Band Name: Wahgoshig First Nation

Reserve Name: Alderville I.R No. 37
Band Name: Alderville First Nation

Reserve Name: Aroland Indian Settlement
Band Name: Aroland

Reserve Name: Big Grassy River I.R. No. 35G
Band Name: Big Grassy First Nation

Reserve Name: Big Island Mainland 93
Band Name: Anishnaabeg of Naongashiing

Reserve Name: Cape Croker Island I.R. No. 27, Neyaashiinigmiing Reserve
Band Name: Chippewas of Nawash First Nation

Reserve Name: Chippewas of the Thames
Band Name: Chippewas of the Thames First Nation

Reserve Name: Chapleau I.R. No. 74A
Band Name: Chapleau Ojibway First Nation

Reserve Name: Christian Island I.R. No.30
Band Name: Beausoleil First Nation

Reserve Name: Cockburn Island 19, 19A
Band Name: Zhiibaahaasing First Nation

Reserve Name: Constance Lake I.R. 92
Band Name: Constance Lake First Nations

Reserve Name: Couchiching I.R. No. 16A
Band Name: Couchiching First Nation

Reserve Name: Curve Lake I.R. No. 35
Band Name: Curve Lake First Nation

Reserve Name: Dalles I.R. No. 38C
Band Name: Ochiichagwe'babigo'ining First Nation

Reserve Name: Duck Lake R.R. No. 76B
Band Name: Brunswick House First Nation

Reserve Name: Dokis I.R. No. 9
Band Name: Dokis First Nation

Reserve Name: Eagle Lake I.R. No. 27
Band Name: Eagle Lake First Nation

Reserve Name: English River I.R. No.21
Band Name: Grassy Narrows First Nation

Reserve Name: Factory Island I.R. No. 1
Band Name: Moose Factory First Nation

Reserve Name: Georgina Island I.R. No. 33
Band Name: Chippewas of Georgina Island First Nation

Reserve Name: Gibson I.R. No. 31 Wahta mohawk
Band Name: Mohawks of Gibson

Reserve Name: Golden Lake No. 39
Band Name: Algonquins Golden Lake First Nation

Reserve Name: Henvey Inlet I.R. No. 2 French River I.R. 13
Band Name: Henvey Inlet First Nation

Reserve Name: Hiawatha I.R. No.36
Band Name: Ojibways of Hiawatha First Nation

Reserve Name: Islington I.R No. 29
Band Name: Wabasemoong Independent Nations

Reserve Name: Kenora I.R. No. 38B
Band Name: Wauzhushk Onigum Nation

Reserve Name: Kettle Point I.R. No. 44
Band Name: Chippewas of Kettle and Stony Point First Nation

Reserve Name: Lac des Milles Lacs I.R. 22A1, Seine River I.R. 22A2
Band Name: Lac des Milles Lacs

Reserve Name: Lac Suel I.R. No. 28
Band Name: Lac Suel Nation

Reserve Name: Lake Helen I.R. No. 53A
Band Name: Red Rock Band

Reserve Name: Long Lake I.R. No. 77
Band Name: Ginoogaming First Nation

Reserve Name: Long Lake I.R. No. 58
Band Name: Long Lake No. 58 First Nation

Reserve Name: Magnetewan I.R No. 1
Band Name: Magnetewan First Nation

Reserve Name: Manitou Rapids I.R. No. 11
Band Name: Rainy River First Nation

Reserve Name: Matachewan I.R 72
Band Name: Matachewan First Nation

Reserve Name: Mattagami I.R No.71
Band Name: Mattagami First Nation

Reserve Name: Mississagi River I.R No.8
Band Name: Mississauga First Nation

Reserve Name: Mobert I.R No. 82
Band Name: Pic Mobert First Nation

Reserve Name: Moose Point I.R No. 79
Band Name: Moose Deer Point First Nation

Reserve Name: Moravian I.R. No. 47
Band Name: Delaware First Nation

Reserve Name: Muncey Delaware Nation No. 1
Band Name: Munsee-Delaware First Nation

Reserve Name: Neguaguon Lake I.R No. 25d
Band Name: Lac La Croix First Nation

Reserve Name: New Credit I.R 40A
Band Name: Mississaugas of the New Credit First Nation

Reserve Name: New Post 69, 69a
Band Name: New Post First Nation

Reserve Name: Nipissing I.R No. 10
Band Name: Nipissing First Nation

Reserve Name: Northwest Angle I.R No. 33B and Whitefish Bay I.R. No. 33a
Band Name: Northwest Angle No. 33 First Nation

Reserve Name: Oneida I.R No. 41
Band Name: ONA YO TE'A:KA

Reserve Name: Osnaburgh I.R No. 63A, 63B
Band Name: Osnaburgh First Nation

Reserve Name: Parry Island I.R No. 16
Band Name: Wasauksing First Nation

Reserve Name: Pays Plat I.R. No. 51
Band Name: Pays Plat First Nation

Reserve Name: Pic River I..R. No. 50
Band Name: Ojibways of Pic River No. 50 First Nation

Reserve Name: Rainy Lake I.R No. 17A, 17B
Band Name: Naicatchewenin First Nation

Reserve Name: Rainy Lake I.R. 26A
Band Name: ` Nicickousemenecaning First Nation

Reserve Name: Rainy Lake I.R. No. 18c
Band Name: Stanjikoming First Nation

Reserve Name: Rama I.R. No. 32
Band Name: Chippewas of Mnjikaning First Nation

Reserve Name: Rat Portage I.R No. 38A
Band Name: Washagamis Bay First Nation

Reserve Name: Rocky Bay I.R. No. 1
Band Name: Rocky Bay First Nation

Reserve Name: Sabaskong Bay 32c, Whitefish Bay 32a, Yellow Girl Bay 32b
Band Name: Naotkamegwanning Anishnabe First Nation

Reserve Name: Sabaskong Bay I.R 35D
Band Name: Ojibways of Onegaming First Nation

Reserve Name: Sarnia I.R.No.45
Band Name: Chippewas of Sarnia

Reserve Name: Saug-A-Gaw-Sing I.R. No. 1
Band Name: Big Island First Nation

Reserve Name: Saugeen I.R. No. 29
Band Name: Chippewas of Saugeen First Nation

Reserve Name: Savant Lake Indian Settlement
Band Name: Saugeen Nation

Reserve Name: Scugog I.R No. 34
Band Name: Mississauga of Scugog First Nation

Reserve Name: Seine River I.R. No. 23A, 23B, Sturgeon Falls No. 23
Band Name: Seine River First Nation

Reserve Name: Serpent River I.R. No. 7
Band Name: Serpent River First Nation

Reserve Name: Shawanaga I.R. No. 17
Band Name: Shawanaga First Nation

Reserve Name: Sheguiandah I.R. No. 24
Band Name: Sheguiandah First Nation

Reserve Name: Sheshegwaning I.R. No. 20
Band Name: Sheshegwaning First Nation

Reserve Name: Shoal Lake I.R. No 39A
Band Name: Shoal Lake No. 39 First Nation

Reserve Name: Shoal Lake I.R. No 40
Band Name: Shoal Lake No. 40 First Nation

Reserve Name: Six Nations I.R. No. 40
Band Name: Six Nations of the Grand River Territory

Reserve Name: Slate Falls Indian Settlement
Band Name: Slate Falls Nation

Reserve Name: Spanish River I.R. No. 5
Band Name: Sagamok Anishnawbek

Reserve Name: Sucker Creek I.R NO. 23
Band Name: Sucker Creek First Nation

Reserve Name: Thessalon I.R. No. 12
Band Name: Thessalon First Nation

Reserve Name: Tyendinaga Mohawk Territory
Band Name: Mohawks of the Bay of Quinte

Reserve Name: Wabauskang 21
Band Name: Wabauskang First Nation

Reserve Name: Wabigoon Lake I.R No. 27
Band Name: Wabigoon Lake Ojibway Nation

Reserve Name: Wahnapitae 11
Band Name: Wahnapitae First Nation

Reserve Name: Walpole Island I.R. No.46
Band Name: Walpole Island First Nation

Reserve Name: West Bay I.R. No. 22
Band Name: West Bay First Nation

Reserve Name: Whitefish Bay I.R No. 32A
Band Name: Whitefish Bay First Nation

Reserve Name: Whitefish Bay I.R No. 34A and Lake of the Woods I.R No. 37
Band Name: Northwest Angle No. 37 First Nation

Reserve Name: Whitefish Lake I.R. No. 6
Band Name: Whitefish Lake First Nation

Reserve Name: Whitefish River I.R. No. 4
Band Name: Whitefish River First Nation

Reserve Name: Wikewemikong I.R. No. 26
Band Name: Wikwemikong Unceded First Nation

APPENDIX B

TAB 3 UNORGANIZED TOWNSHIPS

Networks provides service to numerous Unorganized geographic townships. These townships are not incorporated as municipalities.

APPENDIX B

TAB 4 MUNICIPALITIES IN WHICH A PORTION OF THE MUNICIPALITY IS SERVED BY THE LICENSEE AND ANOTHER PORTION OF THE MUNICIPALITY IS SERVED BY ANOTHER DISTRIBUTOR

Name of Municipality:	**Township of Alfred and Plantagenet**
Formerly Known As:	Township of Alfred, Village of Alfred, Township of North Plantagenet, Village of Plantagenet, as at December 31, 1996.
Area Not Served By Networks:	The area served by Hydro 2000 Inc. described as the former Villages of Alfred and Plantagenet as more particularly set out in Licence No. ED-2002-0542.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**Town of Amherstburg**
Formerly Known As:	Town of Amherstburg, Township of Anderdon, Township of Malden, as at December 31, 1997.
Area Not Served By Networks:	The area served by Essex Powerlines Corporation described as the former Town of Amherstburg as more particularly set out in Licence No. ED-2002-0499.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	Two industrial (former Direct Class) customers located at 381 Front Road North, Amherstburg ON, and 99 Thomas Road, Amherstburg ON

Name of Municipality:	**Township of Asphodel-Norwood**
Formerly Known As:	Township of Asphodel, Village of Norwood, as at December 31, 1997.

Area Not Served By Networks:	The area served by Peterborough Distribution Inc. described as the former Village of Norwood as more particularly set out in Licence No. ED-2002-0504.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**Township of Atikokan**
Formerly Known As:	Same
Area Not Served By Networks:	The area served by Atikokan Hydro Inc. as set out in Licence No. ED-2003-0001.
Networks assets within area not served by Networks:	No
Customer(s) within area not Served by Networks:	No

Name of Municipality:	**Town of Aylmer as at January 1, 1998.**
Formerly Known As:	Same
Area Not Served By Networks:	The area served by Erie Thames Powerlines Corporation described as the Town of Aylmer as more particularly set out in Licence No. ED-2002-0156.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**City of Belleville**
Formerly Known As:	City of Belleville, Township of Thurlow, City of Quinte West, as at December 31, 1997.
Area Not Served By Networks:	The area served by Veridian Connections Inc. described as the former City of Belleville as more particularly set out in Licence No. ED-2002-0503.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**Town of the Blue Mountains**
Formerly Known As:	Town of Thornbury, Township of Collingwood, as at December 31, 1997.
Area Not Served By Networks:	The area served by COLLUS Power Corp. described as the former Town of Thornbury as more particularly set out in Licence No. ED-2002-0518.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**Municipality of Bluewater**
Formerly Known As:	Township of Hay, Township of Stanley, Village of Bayfield, Village of Hensall, Village of Zurich, as at December 31, 2000.
Area Not Served By Networks:	The area served by Festival Hydro Inc. described as the former Village of Hensall, and the former Village of Zurich as more particularly set out in Licence No. ED-2002-0513.

Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**Town of Bracebridge**
Formerly Known As:	Townships of Macaulay, Draper, Monck, Oakely, Town of Bracebridge, as at December 31, 1970.
Area Not Served By Networks:	The area served by Lakeland Power Distribution Ltd. described as the former Town of Bracebridge, as more particularly set out in Licence No. ED-2002-0540.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	One industrial customer located at 154 Beaumont Drive, Bracebridge, ON.

Name of Municipality:	**Town of Bradford-West Gwillimbury**
Formerly Known As:	Town of Bradford, Township of West Gwillimbury, as at December 31, 1990.
Area Not Served By Networks:	The area served by Barrie Hydro Distribution Inc. described as the former Town of Bradford as more particularly set out in Licence No. ED-2002-0534.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**County of Brant (Initially known as City of Brant-on-the-Grand)**
Formerly Known As:	County of Brant, Town of Paris, Township of Brantford, Township of Burford, Township of Oakland, Township of Onondaga, Township of South Dumfries, as at December 31, 1998.
Area Not Served By Networks:	The area served by Brant County Power Inc. described as the former Village of Burford, the former Town of Paris, the former Township of Brantford and the former Police Village of St. George (in the former Township of South Dumfries) as more particularly set out in Licence No. ED-2002-0522. The area served by Cambridge and North Dumfries Hydro Inc. as particularly set out in Licence No. ED-2002-0574.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**Township of Brock**
Formerly Known As:	Village of Beaverton, Village of Cannington, Township of Brock, Township of Thorah, as at December 31, 1973.
Area Not Served By Networks:	The area served by Veridian Connections Inc. described as the former Villages of Beaverton and Cannington and the former Police Village of Sunderland (in the former Township of Brock) as more particularly set out in Licence No. ED-2002-0503.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**Municipality of Brockton**
Formerly Known As:	Township of Greenock, Township of Brant, Town of Walkerton, as at

	December 31, 1998.
Area Not Served By Networks:	The area served by Westario Power Inc. described as the former Town of Walkerton and the portion of the former Police Village of Elmwood (in the former Township of Brant) as more particularly set out in Licence No. ED-2002-0515.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**Township of Brooke-Alvinston**
Formerly Known As:	Township of Brooke, Village of Alvinston
Area Not Served By Networks:	The area served by Bluewater Power Distribution Corp. described as the former Village of Alvinston as more particularly set out in Licence No. ED-2002-0517.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**Municipality of Central Elgin**
Formerly Known As:	Township of Yarmouth, Village of Belmont, Village of Port Stanley, as at December 31, 1997.
Area Not Served By Networks:	The area served by Erie Thames Powerlines Corporation described as the former Villages of Belmont and Port Stanley as more particularly set out in Licence No. ED-2002-0516.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**Municipality of Central Huron**
Formerly Known As:	Township of Goderich, Township of Hullett, Town of Clinton, as at December 31, 2000.
Area Not Served By Networks:	The area served by Clinton Power Corporation described as the former Town of Clinton as more particularly set out in Licence No. ED-2002-0496..
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**Township of Centre Wellington**
Formerly Known As:	Town of Fergus, Village of Elora, Township of West Garafraxa, Township of Nichol, Township of Pilkington, as at December 31, 1998.
Area Not Served By Networks:	The area served by Centre Wellington Hydro Ltd. described as the former Town of Fergus and the former Village of Elora as more particularly set out in Licence No. ED-2002-0498.
Networks Assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**Municipality of Chatham-Kent**
Formerly Known As:	City of Chatham, County of Kent, Town of Blenheim, Town of Bothwell, Town of Dresden, Town of Ridgetown, Town of Tilbury, Town of Wallaceburg, Village of Erie Beach, Village of Erieau, Village of Highgate, Village of Thamesville, Village of Wheatley, Township of Camden, Township of Chatham, Township of Dover, Township of Harwich, Township of Howard, Township of Orford, Township of

	Raleigh, Township of Rodney, Township of Tilbury East, Township of Zone, as at December 31, 1997.
Area Not Served By Networks:	The area served by Chatham-Kent Hydro Inc. described as the former City of Chatham, former Police Village of Merlin (straddling the former townships of Raleigh and Tilbury East), former Village of Erieau, former Village of Thamesville, former Town of Bothwell, former Village of Wheatley, former Town of Dresden, former Town of Blenheim, former Town of Tilbury, former Town of Ridgetown, and the former Town of Wallaceburg as more particularly set out in Licence No. ED-2002-0563.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**Municipality of Clarington**
Formerly Known As:	Town of Bowmanville, Village of Newcastle, Township of Clarke, Township of Darlington, as at December 31, 1973.
Area Not Served By Networks:	The area served by Veridian Connections Inc. described as the former Town of Bowmanville, the former Police Village of Orono (in the former Township of Clarke), the former Town of Newcastle as more particularly set out in Licence No. ED-2002-0503
N**etworks assets within area not served by Networks:**	Yes
Customer(s) within area not served by Networks:	One Industrial customer located at 410 Waverley Road, Bowmanville ON.

Name of Municipality:	**Township of Clearview**
Formerly Known As:	Town of Stayner, Village of Creemore, Township of Nottawasaga, Township of Sunnidale, as at December 31, 1993.
Area Not Served By Networks:	The area served by COLLUS Power Corp. described as the former Town of Stayner and the former Village of Creemore as more particularly set out in Licence No. ED-2002-0518.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**Town of Cochrane**
Formerly Known As:	Town of Cochrane, Township of Glackmeyer, Unorganized Twp. of Lamarche, as at December 31, 1999.
Area Not Served By Networks:	The area served by Northern Ontario Wires Inc. described as the former Town of Cochrane as more particularly set out in Licence No. ED-2002-0018
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**Township of Cramahe**
Formerly Known As:	Village of Colborne, Township of Cramahe, as at December 31, 2000.
Area Not Served By Networks:	The area served by Lakefront Utilities Inc. described as the former Village of Colborne as more particularly set out in Licence No. ED-

	2002-0545.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**Municipality of Dutton/Dunwich**
Formerly Known As:	Township of Dunwich, Village of Dutton, as at December 31, 1997.
Area Not Served By Networks:	The area served by Dutton Hydro Limited described as the former Village of Dutton as more particularly set out in Licence No. ED-2003-0025.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**Town of East Gwillimbury as at March 31, 1999**.
Formerly Known As:	Same
Area Not Served By Networks:	The area served by Newmarket-Tay Power Distribution Ltd. as particularly set out in Licence No. ED- 2007-0624.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**Township of East Luther Grand Valley**

Formerly Known As:	Township of East Luther, Village of Grand Valley, as at December 31, 1994.
Area Not Served By Networks:	The area served by Grand Valley Energy Inc. described as the former Village of Grand Valley as more particularly set out in Licence No. ED-2002-0512.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**The Township of East Zorra-Tavistock**
Formerly Known As:	Township of East Zorra, Town of Tavistock, as at December 31, 1997.
Area Not Served By Networks:	The area served by Erie Thames Powerlines Corp. described as the former Town of Tavistock as more particularly set out in Licence No. ED-2002-0516.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**Township of Edwardsburgh/Cardinal**
Formerly Known As:	Village of Cardinal, Township of Edwardsburgh, as at December 31, 2000.
Area Not Served By Networks:	The area served by Rideau St. Lawrence Distribution Inc. described as the former Village of Cardinal as more particularly set out in Licence No. ED-2003-0003.
Networks assets within area not served by Networks:	Yes

Customer(s) within area not served by Networks:	No
Name of Municipality:	**Township of Essa as at March 31, 1999**.
Formerly Known As:	Same
Area Not Served By Networks:	The area served by Barrie Hydro Distribution Inc. described as the former Police Village of Thorton as more particularly set out in Licence No. ED-2002-0534.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No
Name of Municipality:	**Town of Essex**
Formerly Known As:	Town of Essex, Town of Harrow, Township of North Colchester, Township of South Colchester, as at December 31, 1998.
Area Not Served By Networks:	The area served by E.L.K. Energy Inc. described as the former Town of Essex and the former Town of Harrow as more particularly set out in Licence No. ED-2003-0015.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No
Name of Municipality:	**Town of Gravenhurst**
Formerly Known As:	Formerly the Township of Morrison, the United Townships of Medora and Wood, the Township of Muskoka, the Township of Ryde, the Town of Gravenhurst, as at December 31, 1970.
Area Not Served By Networks:	The area served by Veridian Connections Inc. described as the former

	urban boundary of the Town of Gravenhurst as more particularly set out in Licence No. ED-2002-0503.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**City of Greater Sudbury**
Formerly Known As:	Region of Sudbury, City of Sudbury, City of Valley East, Town of Capreol, Town of Nickel Centre, Town of Onaping Falls, Town of Rayside-Balfour, Town of Walden, as at December 31, 2000.
Area Not Served By Networks:	The area served by Greater Sudbury Hydro Inc. described as the former City of Sudbury, the former townsite of the former Town of Capreol, and the former Town of Conniston (part of former Town of Nickel Centre) as more particularly set out in Licence No. ED-2002-0559.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**Township of Guelph/Eramosa**
Formerly Known As:	Township of Guelph, Township of Eramosa, as at December 31, 1998.
Area Not Served By Networks:	The area served by Guelph Hydro Electric Systems Inc. as more particularly set out in Licence No. ED-2002-0565.
Networks assets within area not served by Networks:	Yes

Customer(s) within area not served by Networks:	No

Name of Municipality:	**City of Hamilton**
Formerly Known As:	Region of Hamilton-Wentworth, City of Hamiton, City of Stoney Creek, Town of Ancaster, Town of Dundas, Town of Flamborough, Township of Glanbrook, as at December 31, 2000.
Area Not Served By Networks:	The area served by Horizon Utilities Corp. described as the former City of Hamilton, the former Police Village of Ancaster, former Town of Dundas, the former Police Village of Lynden (straddling the former Town of Flamborough and Town of Ancaster), the former Village of Waterdown, and the former City of Stoney Creek as more particularly set out in Licence No. ED-2006-0031.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**Town of Hawkesbury as at March 31, 1999**.
Formerly Known As:	Same
Area Not Served By Networks:	The area served by Hydro Hawkesbury Inc. described as the Town of Hawkesbury prior to annexation or amalgamation pursuant to the Minister’s Order or Restructuring Act as more particularly set out in Licence No. ED-2003-0027.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**Town of Huntsville**

Formerly Known As:	Township of Brunel, Village of Port Sydney, Town of Chaffey, Township of Stephenson, Township of of Stisted, Town of Huntsville, as at December 31, 1970.
Area Not Served By Networks:	The area served by Lakeland Power Distribution Ltd. described as the former Town of Huntsville as more particularly set out in Licence No. ED-2002-0540.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	One Industrial customer located at 61 Domtar Road, Huntsville ON.

Name of Municipality:	**Municipality of Huron East**
Formerly Known As:	Village of Brussels, Township of Grey, Township of McKillop, Town of Seaforth, Township of Tuckersmith, as at December 31, 2000.
Area Not Served By Networks:	The area served by Festival Hydro Inc. described as the former Village of Brussels and the former Town of Seaforth as more particularly set out in Licence No. ED-2002-0513.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**Township of Huron-Kinloss**
Formerly Known As:	Township of Huron (former Police Village of Ripley amalgamated with twp in 1995), Township of Kinloss, Village of Lucknow, as at December 31, 1998.
Area Not Served By Networks:	The area served by Westario Power Inc. described as the former Police Village of Ripley (in the former Township of Huron) and the

	former Village of Lucknow as more particularly set out in Licence No. ED-2002-0515.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**Municipality of Huron Shores**
Formerly Known As:	Township of Day & Bright Add'l, Township of Thessalon, Township of Thompson, Village of Iron Bridge, as at December 31, 1998.
Area Not Served By Networks:	The area served by Great Lakes Power Limited described as part of the former Township of Thessalon or as more particularly set out in Licence No. ED-1999-0227
Networks assets within area not served by Networks:	No
Customer(s) within area not served by Networks:	No

Name of Municipality:	**Town of Ingersoll**
Formerly Known As:	Same
Area Not Served By Networks:	The area served by Erie Thames Powerlines Corporation described as the Town of Ingersoll as more particularly set out in Licence No. ED-2002-0516.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not	

served by Networks:	No
Name of Municipality:	**Town of Iroquois Falls as at March 31, 1999**.
Formerly Known As:	Same
Area Not Served By Networks:	The area served by Northern Ontario Wires Inc. described as the Town of Iroquois Falls as more particularly set out in Licence No. ED-2002-0018.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No
Name of Municipality:	**City of Kenora**
Formerly Known As:	Town of Kenora, Town of Keewatin, Town of Jaffray Melick, as at December 31,1999.
Area Not Served By Networks:	The area served by Kenora Hydro Electric Corporation Ltd. described as the former Town of Kenora and part of the former Town of Keewatin as more particularly set out in Licence No. ED-2003-0030.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No
Name of Municipality:	**Township of Killaloe, Hagarty and Richards**
Formerly Known As:	Township of Hagarty and Richards, Village of Killaloe, as at June 30, 1999

Area Not Served By Networks:	The area served by Ottawa River Power Corp. described as the former Village of Killaloe as more particularly set out in Licence No. ED-2002-0033.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No
Name of Municipality:	**Municipality of Kincardine**
Formerly Known As:	Town of Kincardine, Township of Bruce (Village of Tiverton, Township of Bruce amalgamation), Township of Kincardine, as at December 31, 1998.
Area Not Served By Networks:	The area served by Westario Power Inc. described as the former Town of Kincardine as more particularly set out in Licence No. ED-2002-0515.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No
Name of Municipality:	**Township of King as at March 31, 1999**
Formerly Known As:	Same
Area Not Served By Networks:	The area served by PowerStream Inc. as more particularly set out in Licence No. ED-2004-0420. The area served by Newmarket-Tay Power Distribution Ltd. as more particularly set out in Licence No. ED-2007-0624.

Networks assets within area not served by Networks: Yes

Customer(s) within area not Served by Networks: No

Name of Municipality: **City of Kingston**

Formerly Known As: City of Kingston, Township of Kingston, Township of Pittsburgh, as at December 31, December 31, 1997.

Area Not Served By Networks: The area served by Kingston Electricity Distribution Ltd. described as the former City of Kingston, the former Township of Kingston, and part of the former Township of Pittsburgh as more particularly set out in Licence No. ED-2003-0057.

The area served by Canadian Niagara Power Inc. described as part of the former Township of Pittsburgh as more particularly set out in Licence No. ED-2002-0572.

Networks assets within area not served by Networks: Yes

Customer(s) within area not served by Networks: No

Name of Municipality: **Town of Kingsville**

Formerly Known As: Town of Kingsville, Township of Gosfield North, Township of Gosfield South, as at December 31, 1997.

Area Not Served By Networks: The area served by E.L.K. Energy Inc. described as the former Town of Kingsville and the former Police Village of Cottam (in the former Township of Gosfield North), including Part Lot 269 Part 1 12R-23403, Part Lot 268 Part 1 12R-23674 and Part Lot 269RP 12R-1331 Parts 4

	and 5 located at 168 Belle River Road North, as more particularly set out in Licence No. ED-2003-0015.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**Town of Lakeshore**
Formerly Known As:	Township of Lakeshore, (Jan 1998: Town of Belle River, Township of Maidstone amalgamated into Lakeshore Township), Township of Rochester, Township of Tillbury North, Township of Tillbury West, as at December 31, 1998.
Area Not Served By Networks:	The area served by E.L.K. Energy Inc. described as the former Police Village of Comber (in the former Township of Tillbury West) and the former Town of Belle River as more particularly set out in Licence No. ED-2003-0015.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**Municipality of Leamington**
Formerly Known As:	Town of Leamington, Township of Mersea, as at December 31, 1998.
Area Not Served By Networks:	The area served by Essex Powerlines Corporation described as the former Town of Leamington as more particularly set out in Licence No. ED-2002-0499.
Networks assets within area not served by Networks:	Yes

Customer(s) within area not served by Networks:	No

Name of Municipality:	**Township of Leeds and the Thousand Islands**
Formerly Known As:	Township of Front of Leeds and Lansdowne, Township of Rear of Leeds and Lansdowne, Township of Front of Escott, as at December 31, 2000.
Area Not Served By Networks:	The area served by Canadian Niagara Power Inc. described as part of the former Township of the Front of Leeds and Lansdowne as more particularly set out in Licence No. ED-2002-0572.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**Municipality of Magnetawan**
Formerly Known As:	Township of Chapman, Village of Magnetawan, Unorganized Township of Croft, as at December 31, 1997.
Area Not Served By Networks:	The area served by Lakeland Power Distribution Ltd. described as the former Village of Magnetawan as more particularly set out in Licence No. ED-2002-0540.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**Town of Minto**

Formerly Known As:	Township of Minto, Town of Palmerston, Town of Harriston, Village of Clifford, as at December 31, 1998.
Area Not Served By Networks:	The area served by Westario Power Inc. described as the former Town of Harriston, the former Town of Palmerston, and the former Village of Clifford as more particularly set out in Licence No. ED-2002-0515.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**The Corporation of the Town of Mississippi Mills**
Formerly Known As:	Town of Almonte, Township of Pakenham, Township of Ramsay, as at December 31, 1998.
Area Not Served By Networks:	The area served by Ottawa River Power Corp. described as the former Town of Almonte as more particularly set out in Licence No. ED-2003-0033.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**Town of New Tecumseth**
Formerly Known As:	Town of Alliston, the Village of Beeton, the Village of Tottenham and the portion of the Township of Tecumseth, as at December 31, 1991.
Area Not Served By Networks:	The area served by Barrie Hydro Distribution Inc. described as the former Town of Alliston, the former Village of Beeton and the former Village of Tottenham (all in the former Township of Tecumseth) as more particularly set out in Licence No. ED-2002-0534.

Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	One Industrial customer located in the former Town of Alliston.

Name of Municipality:	**The Corporation of Norfolk County**
Formerly Known As:	Township of Norfolk, Township of Delhi, Town of Simcoe, City of Nanticoke (westerly 'half' only), as at December 31, 2000.
Area Not Served By Networks:	The area served by Norfolk Power Distribution Inc. described as the former Town of Delhi (in the former Township of Delhi), the westerly half of the former City of Nanticoke, the former Village of Port Rowan (in former Township of Norfolk), and the former Town of Simcoe as more particularly set out in Licence No. ED-2002-0521.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	One Industrial customer located at Lake Erie and Regional Rd.. 3, Nanticoke, ON.

Name of Municipality:	**Township of North Huron**
Formerly Known As:	Town of Wingham, Village of Blyth, Township of East Wawanosh,as at December 31, 2000.
Area Not Served By Networks:	The area served by Westario Power Inc. described as the former Town of Wingham as more particularly set out in Licence No. ED-2002-0515.
Networks assets within area not served by Networks:	Yes

Customer(s) within area not served by Networks:	Two Industrial customers located at 40621 Amberly Rd., and 200 Water Street Wingham, ON.

Name of Municipality:	**Municipality of North Middlesex**
Formerly Known As:	Township of McGillivray, Township of East Williams, Township of West Williams, Town of Parkhill, Village of Ailsa Craig, as at December 31, 2000.
Area Not Served By Networks:	The area served by Middlesex Power Distribution Corp. described as the former Town of Parkhill as more particularly set out in Licence No. ED-2003-0059.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**The Township of Norwich as at March 31, 1999**.
Formerly Known As:	Township of North Norwich, Township of South Norwich, Township of East Oxford, Village of Norwich, Village of Burgessville, and Police Village of Otterville, as at
Area Not Served By Networks:	The area served by Erie Thames Powerlines Corp. described as the former Village of Norwich, the former Village of Burgessville, and the former Police Village of Otterville as more particularly set out in Licence No. ED-2002-0516.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**City of Ottawa**
Formerly Known As:	Region of Ottawa-Carleton, City of Gloucester, City of Kanata, City of Nepean, City of Ottawa, City of Vanier, Township of Cumberland, Township of Goulbourn, Township of Osgoode, Township of Rideau, Township of West Carleton, Village of Rockcliffe Park, as at December 31, 2000.
Area Not Served By Networks:	The area served by Hydro Ottawa Limited described as the former City of Gloucester, the former City of Kanata, the former City of Nepean, the former City of Ottawa, the former City of Vanier, the former Township of Goulbourn, the former Village of Rockcliffe Park, and the portion of the former Township of Rideau on Long Island, North of Bridge Street, as more particularly set out in Licence No. ED-2002-0556.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No.

Name of Municipality:	**Town of Pelham**
Formerly Known As:	Township of Pelham, Village of Fonthill, as at December 31, 1969.
Area Not Served By Networks:	The area served by Niagara Peninsula Energy Inc.described as the former Village of Fonthill as more particularly set out in Licence No. ED-2002-0555.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**City of Peterborough as at March 31, 1999**.

Formerly Known As:	Same
Area Not Served By Networks:	The area served by Peterborough Distribution Inc. described as the City of Peterborough as more particularly set out in Licence No. ED-2002-0504.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**Municipality of Port Hope**
Formerly Known As:	Town of Port Hope, Township of Hope (initially restructured as Municipality of Port Hope and Hope), as at December 31, 2000.
Area Not Served By Networks:	The area served by Veridian Connections Inc. described as the former Town of Port Hope as more particularly set out in Licence No. ED-2002-0503.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**Township of Puslinch as at March 31, 1999**
Formerly Known As:	Same
Area Not Served By Networks:	The area served by Guelph Hydro Electric Systems Inc. as more particularly set out in Licence No. ED-2002-0565.
Networks assets within area not served by Networks:	Yes

Customer(s) within area not served by Networks:	No
Name of Municipality:	**Municipality of Red Lake**
Formerly Known As:	Township of Red Lake, Township of Golden, as at June 30, 1997.
Area Not Served By Networks:	The area served by Gold Corp Inc. described as part of the former Improvement District of Balmertown.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No
Name of Municipality:	**Township of Russell as at March 31, 1999**.
Formerly Known As:	Same
Area Not Served By Networks:	The area served by Cooperative Hydro Embrun Inc. described as the former Police Village of Embrum as more particularly set out in Licence No. ED-2002-0493.
Networks assets within area not served by Networks:	No
Customer(s) within area not served by Networks:	No
Name of Municipality:	**Township of Sables-Spanish Rivers**
Formerly Known As:	Town of Massey, Town of Webbwood, Township of the Spanish River, as at June 30, 1997.
Area Not Served By Networks:	The area served by Espanola Regional Hydro Distribution Corp. described as the former Town of Massey and the former Town of Webbwood as more particularly set out in Licence No. ED-2002-0502.

Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**Town of Saugeen Shores**
Formerly Known As:	Township of Saugeen, Town of Southampton, Town of Port Elgin, as at December 31, 1998.
Area Not Served By Networks:	The area served by Westario Power Inc. described as the former Town of Southampton and the former Town of Port Elgin as more particularly set out in Licence No. ED-2002-0515.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**City of St. Thomas as at March 31, 1999**.
Formerly Known As:	Same
Area Not Served By Networks:	The area served by St. Thomas Energy Inc. described as the City of St. Thomas as more particularly set out in Licence No. ED-2002-0523.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	One Industrial customer located at 1 Cosma Court

Name of Municipality:	**Township of Scugog**
Formerly Known As:	Township of Scugog, Township of Cartwright, Township of Reach, Village of Port Perry, as at December 31. 1973.

Area Not Served By Networks:	The area served by Veridian Connections Inc. described as the former Village of Port Perry as more particularly set out in Licence No. ED-2002-0503.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**Municipality of Sioux Lookout**
Formerly Known As:	Town of Sioux Lookout, as at December 31, 1997
Area Not Served By Networks:	The area served by Sioux Lookout Hydro Inc. described as the Municipality of Sioux Lookout as more particularly set out in Licence No. ED-2002-0514.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**Township of Smith-Ennismore-Lakefield**
Formerly Known As:	Village of Lakefield, Township of Smith-Ennismore (formerly Township of Smith and Township of Ennismore), as at December 31, 2000.
Area Not Served By Networks:	The area served by Peterborough Distribution Inc. described as the former Village of Lakefield as more particularly set out in Licence No. ED-2002-0504.
Networks assets within area not served by Networks:	Yes

Customer(s) within area not served by Networks:	No
Name of Municipality:	**Municipality of South Bruce**
Formerly Known As:	Township of Mildmay-Carrick, Township of Teeswater-Culross, (Jan 1998: Village of Teeswater, Township of Culross amalgamated into the Township of Teeswater-Culross. Village of Mildmay, Township of Carrick amalgamated into the Township of Mildmay-Carrick), as at December 31, 1997.
Area Not Served By Networks:	The area served by Westario Power Inc. described as the former Village of Mildmay and the former Village of Teeswater as more particularly set out in Licence No. ED-2002-0515.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No
Name of Municipality:	**Township of South Dundas**
Formerly Known As:	Township of Matilda, Township of Williamsburg, Village of Iroquois, Village of Morrisburg, as at December 31, 1997.
Area Not Served By Networks:	The area served by Rideau St. Lawrence Distribution Inc. described as the former Police Village of Williamsburg, the former Village of Morrisburg, and the former Village of Iroquois as more particularly set out in Licence No. ED-2003-0003.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**Township of South Glengarry**
Formerly Known As:	Township of Charlottenburgh, Township of Lancaster, Village of Lancaster, Police Village of Martintown, as at December 31, 1997.
Area Not Served By Networks:	The area served by the Cornwall Street Railway Light and Power Company Limited described as part of the former Township of Charlottenburgh as more particularly set out in Licence No. ED-2004-0405.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	**Three Solar PV generator customers located at:** 1. Part of Lots 5 & 6, Concession 5 2. Part of Lots 15 & 16, Concession 5 & 6 3. Lot 41, 41A, Plan 107 except Part 20 and 20A on 14R299, s/t IL 3007, TCH 4416 and Plan 107 – Pt Lot 40 as in AR 1461, Except Pt 1 & 2, 14R2143 S/T TCH 4357

Name of Municipality:	**Municipality of South Huron**
Formerly Known As:	Township of Stephen, Township of Usborne, Town of Exeter, as at December 31, 2000.
Area Not Served By Networks:	The area served by Festival Hydro Inc. described as the former Police Village of Dashwood as more particularly set out in Licence No. ED-2002-0513.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**Township of South Stormont**
Formerly Known As:	Township of Osnabruck, Township of Cornwall, as at December 31, 1997
Area Not Served By Networks:	The area served by Cornwall Street Railway Light and Power

	Company Limited described as part of the former Township of Cornwall and part of the former Township of Osnabruk as more particularly set out in Licence No. ED-2004-0405.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**Township of Southgate**
Formerly Known As:	Village of Dundalk, Township of Egremont, Township of Proton, Police Village of Holstein, as at December 31, 1999.
Area Not Served By Networks:	The area served by Wellington North Power Inc. described as the former Police Village of Holstein as more particularly set out in Licence No. ED-2002-0511.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**The Township of South-West Oxford**
Formerly Known As:	Township of West Oxford, Township of Dereham, Village of Beachville, as at December 31,. 1974.
Area Not Served By Networks:	The area served by Erie Thames Powerlines Corp. described as the former Village of Beachville as more particularly set out in Licence No. ED-2002-0516.
Networks assets within area not served by Networks:	Yes

Customer(s) within area not served by Networks:	No

Name of Municipality:	**Township of Strathroy-Caradoc**
Formerly Known As:	Town of Strathroy, Township of Caradoc**,** as at December 31, 2000.
Area Not Served By Networks:	The area served by Middlesex Power Distribution Corp. described as the former Police Village of Mount Brydges (in the former Township of Caradoc) and the former Town of Strathroy as more particularly set out in Licence No. ED-2003-0059.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**Township of Tay**
Formerly Known As:	Village of Port NcNicoll, Village of Victoria Harbour, the Township of Medonte, Township of Tay, Township of Tiny, Township of Flos, Police Village of Waubaushene, as at December 31, 1996.
Area Not Served By Networks:	The area served by Newmarket-Tay Power Distribution Ltd. as more particularly set out in Licence No. ED-2007-0624.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**Town of Tecumseh**
Formerly Known As:	Town of Tecumseh, Village of St. Clair Beach, Township of Sandwich South, as at December 31, 1998.
Area Not Served By Networks:	The area served by Essex Powerlines Corporation described as the former Town of Tecumseh and the former Village of St. Clair Beach as more particularly set out in Licence No. ED-2002-0499.

Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**Township of Uxbridge**
Formerly Known As:	Town of Uxbridge, Township of Scott, Township of Uxbridge, as at December 31. 1973.
Area Not Served By Networks:	The area served by Veridian Connections Inc. described as the former Town of Uxbridge as more particularly set out in Licence No. ED-2002-0503.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**Township of Warwick**
Formerly Known As:	Village of Watford, Township of Warwick, as at December 31, 1997.
Area Not Served By Networks:	The area served by Bluewater Power Distribution Corp. described as the former Village of Watford as more particularly set out in Licence No. ED-2002-0517.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**Township of Wellington North**
Formerly Known As:	Town of Mount Forest, Village of Arthur, Township of Arthur, Township

	of West Luther, as at December 31, 1998.
Area Not Served By Networks:	The area served by Wellington North Power Inc. described as the former Village of Arthur and the former Town of Mount Forest as more particularly set out in Licence No. ED-2002-0511.
Networks assets within area not served by Networks:	No
Customer(s) within area not served by Networks:	No

Name of Municipality:	**Township of West Grey**
Formerly Known As:	Township of West Grey, Town of Durham (Jan 2000 Township Bentinck, Township of Glenelg, Town Normanby, Village of Neustadt amalgamated into the Township of West Grey), as at December 31, 1999.
Area Not Served By Networks:	The area served by Westario Power Inc. described as the former Village of Neustadt and a portion of the former Police Village of Elmwood (in the former Township of Bentinck) as more particularly set out in Licence No. ED-2002-0515.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**Municipality of West Nipissing**
Formerly Known As:	Town of Cache Bay, Town of Sturgeon Falls, Township of Caldwell, Township of Field, Township of Springer, as at December 31, 1998.
Area Not Served By Networks:	The area served by West Nipissing Energy Services Ltd. described as the former Town of Cache Bay and the former Town of Sturgeon Falls as more particularly set out in Licence No. ED-2002-0562.

Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**Municipality of West Perth**
Formerly Known As:	Township of Logan, Township of Fullarton, Township of Hibbert, Town of Mitchell, Police Village of Dublin, as at December 31, 1997.
Area Not Served By Networks:	The area served by West Perth Power Inc. described as the former Town of Mitchell and the former Police Village of Dublin as more particularly set out in Licence No. ED-2002-0508.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**Town of Whitby**
Formerly Known As:	Same
Area Not Served By Networks:	The area served by Whitby Hydro Electric Corporation and the area served by Veridian Connections Inc. as more particularly set out in Licence No. ED-2002-0571.

Name of Municipality:	**Township of Whitewater Region**
Formerly Known As:	Township of Ross, Township of Westmeath, Village of Beachburg, Village of Cobden, as at December 31, 2000.
Area Not Served By Networks:	The area served by Ottawa River Power Corp. described as the former Village of Beachburg as more particularly set out in Licence No. ED-2003-0033.
Networks assets within area not served by Networks:	Yes

Customer(s) within area not served by Networks:	No

Name of Municipality:	**City of Woodstock as at March 31, 1999**.
Formerly Known As:	Same
Area Not Served By Networks:	The area served by Woodstock Hydro Services Inc. described as the City of Woodstock as more particularly set out in Licence No. ED-2003-0011, including the Boot Hill Development located on part of lots 3, 7, 8, 11, 12, 13 and registered plan 86 and 501, and three customers on Mill Street with civic address numbers 388, 390 and 410.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**Township of Zorra**
Formerly Known As:	Township of West Zorra, Township of East Nissouri, Township of North Oxford, Village of Embro, Village of Thamesford , as at December 31, 1997.
Area Not Served By Networks:	The area served by Erie Thames Powerlines Corp. described as the former Village of Embro and the former Village of Thamesford as more particularly set out in Licence No. ED-2002-0516.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	**The Town of Penetanguishene as at March 31, 1999**
Formerly Known As:	Same

Area Not Served By Networks:	The area served by Barrie Hydro Distribution Inc. described as part of the Town of Penetanguishene as more particularly set out in Licence No. ED-2002-0534.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

APPENDIX B

TAB 5 CONSUMERS EMBEDDED WITHIN ANOTHER DISTRIBUTOR BUT SERVED BY THE LICENSEE

(Note also that each municipality noted in Tab 5 is a municipality served almost entirely by another distributor but in which the Licensee serves one or more consumers.)

Name of Municipality:	**City of Cornwall**
Assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	The customers located at and 501 Wallrich Avenue.

Name of Municipality:	**County of Haldimand**
Assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	One customer located in Caledonia, Ont.

Name of Municipality:	**City of Niagara Falls**
Assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	Three customers located at 8001 Daly Street, 7780 Stanley Ave, 6225 Progress Street

Name of Municipality:	**City of St. Thomas**
Assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	One industrial customer located at 1 Cosma Court.

Ontario's Long-Term Energy Plan

Building Our Clean Energy Future

Ontario

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contents

foreword

Maintaining a clean, modern and reliable electricity system for all Ontarians is this government's number one energy priority. Ontario families, businesses and the economy rely on the efficiency, dependability and environmental sustainability of electric power. We have to keep the lights on in Ontario homes, schools, hospitals and businesses and power everything from the coffee-maker to the CT scanner. We also need a clean system that won't threaten the health of current and future generations.

Ontarians deserve balanced, responsible long-term energy planning for electricity to ensure that Ontario has clean air, reliable energy and a strong economy for our children and grandchildren. This report represents an update to the McGuinty government's long-term energy plan and outlines how we are helping families and businesses with increasing electricity costs.

Prior to 2003, Ontario's electricity system was weakening and unreliable. Our reliance on coal meant that our electricity sources were polluting and dirty. Between 1995 and 2003, the electricity system lost 1,800 megawatts (MW) of power — the equivalent of Niagara Falls running dry. A brief deregulated pricing experiment in 2002 resulted in sharply increased prices, prompting the government of the time to freeze consumer prices. Energy infrastructure was crumbling, a shortage of supply caused risks of brownouts.

Worst of all, Ontario relied heavily on five air-polluting coal plants. This wasn't just polluting our air, it was polluting our lungs. Doctors, nurses and researchers stated categorically that coal generation was having an impact on health increasing the incidence of various respiratory illnesses. A 2005 study prepared for the government found that the average annual health-related damages due to coal could top $3 billion. For the sake of our well-being, and our children's well-being, we had to put a stop to coal.

Over the past seven years, the McGuinty government has made tremendous progress after inheriting a system with reduced supply and little planning for the future. Today, our system is cleaner, more modern, more reliable and we plan ahead.

The McGuinty government has made electricity cleaner: we are on track to eliminate coal by 2014, the single largest climate change initiative in North America in that timeframe. We have already reduced the use of coal by 70 per cent. Last year our greenhouse gas emissions from the electricity sector reached the lowest they have been in 45 years. In 2009, more than 80 per cent of our generation came from emissions-free sources like wind, water, solar, biogas and nuclear.

Conservation efforts have been working — many Ontario families and businesses are becoming very active energy conservers. Through various programs, Ontarians have conserved more than 1,700 MW of electricity since 2005 — the equivalent of more than half a million homes being taken off the grid.

Today we have enough electricity to power our homes, businesses, schools and hospitals. Our government has increased Ontario's energy capacity by adding over 20 per cent (more than 8,000 MW) of new supply to the system – enough to power two million homes. Investments in Ontario are transforming the electricity system and have helped to make Ontario a leading jurisdiction in North America for renewable and reliable energy. And since 2007, we've used a formal 20-year planning process to help us forecast and meet the province's electricity needs.

Ontario's electricity system is more reliable. Investments in new generation and upgrades to 5,000 kilometres of our transmission and distribution lines — about the width of Canada from coast to coast — have ensured that our electricity system is able to manage peak and sudden swings in demand and supply availability.

We are moving toward a modern, smart electricity system that will help consumers have greater control over their energy usage — even when they're not at home. A smart grid can isolate outages allowing for faster or even automated repair. This will improve overall reliability for all electricity consumers and make it easier for consumers to produce their own power.

As part of the Open Ontario plan, the McGuinty government is moving Ontario from dirty coal dependency to a clean, modern and reliable energy economy that creates jobs. Energy is one of the engines of our economy and employs more than 95,000 Ontarians. Recent investments to modernize the system are helping to create and support jobs and opportunities for people and communities across the province. Ontario's landmark Green Energy and Green Economy Act, 2009 is projected over three years to support over 50,000 direct and indirect jobs in smart grid and transmission and distribution upgrades, renewable energy and conservation.

We've accomplished a great deal in the past seven years, but there is more to do. Ontario has sufficient electricity supply — but we will require more clean power for the future. As Ontario's energy infrastructure ages, we will need to rebuild or create another 15,000 MW of generating capacity over the next 20 years. We will also need to continue to upgrade and update transmission and distribution lines.

While we are proud of our collective efforts so far, we must continue to develop cleaner forms of electricity and foster a conservation-oriented culture. We need to have a balanced low-carbon supply mix to meet energy needs cleanly and reliably — Ontario will be ready for when North America moves to greenhouse gas regulation. We also need to maximize the electricity assets we have and ensure that those assets continue to provide clean, reliable supply.

The necessary, unavoidable investments that Ontario has been making in our electricity system are paid by ratepayers. The cost to bring our system back up to date and build a clean energy economy is having an impact on household and business bills.

We are all paying for previous decades of neglect. In Ontario, in order to have clean air, reliable generation and modernized transmission, residential prices over the next 20 years are expected to increase by about 3.5 per cent per year.

Increases to electricity bills are not easy for Ontario families and businesses. Even though Ontarians are committed to clean air, every increase takes a bite out of take-home income, and that is difficult for families during lean times. To help with rising costs, the McGuinty government has created a number of tax credits for families and seniors to help manage electricity increases. But we need to do more.

In this Plan, and the government's 2010 Economic Outlook and Fiscal Review we have taken steps to ensure that we help families and businesses with electricity costs while investment in clean energy continues. On November 18, 2010, the McGuinty government introduced the Ontario Clean Energy Benefit.

If passed, the Ontario Clean Energy Benefit will give Ontario families, farms and small businesses a 10 per cent benefit on their bills for five years. That would be 10 per cent off your electricity bill every month, effective January 1, 2011.

The proposed Clean Energy Benefit will help families, hard-working small business owners and Ontario farms. The McGuinty government is doing this to help those who are feeling the pinch of the rising cost of living and especially, rising electricity prices. Every little bit helps during lean economic times.

This balanced and responsible Plan sets out Ontario's expected electricity needs and the most efficient ways to meet them.

The Honourable Brad Duguid
Minister of Energy

overview

Ontario Electricity 1906-2003

On October 11, 1910, when Adam Beck lit up a Kitchener street sign that read "For the People," the town went wild, and the electrification of Ontario began. It was the first major project of the Hydro-Electric Power Commission of Ontario, created in 1906 as the world's first publicly owned electric utility. Beck, a municipal and provincial politician, believed that it was essential to the province's economic development that electricity be available to every Ontarian.

The Queenston-Chippawa power station at Niagara (renamed Sir Adam Beck I in 1950) helped Ontario meet the growing demand for electricity during the postwar economic boom. But despite continued expansion, it had become increasingly clear that hydropower alone would not be able to keep up with the province's demand.

As a result, Ontario began to diversify its supply mix in the 1950s, adding new sources of power, including six coal-fired generating stations built near areas where demand was highest. Between the early 1970s and the early 1990s, nuclear power was also added at three generating facilities. In the meantime, in 1974, the Hydro-Electric Power Commission was recognized as a crown corporation and renamed Ontario Hydro.

This trio of electricity sources — hydro, coal and nuclear — would support Ontario's economic prosperity into the 1990s. By then, much of the province's electricity infrastructure was aging and in need of replacement or refurbishment. The system had become unreliable, and there was widespread concern about whether supply would be able to meet projected demand.

Between 1996 and 2003, Ontario's generation capacity fell by six per cent — the equivalent of Niagara Falls running dry, while electricity demand grew by 8.5 per cent. Investments to build new supply and the upkeep of lines were modest. Investments in upgrades to transmission and distribution were less than half of current levels. There were no provincially funded conservation programs.

In 1998, Ontario passed legislation that authorized the establishment of a market in electricity. In April 1999, Ontario Hydro was re-organized into five successor entities. The move to break up Ontario Hydro and partially privatize the electricity system saddled Ontario with a stranded debt of over $20 billion.

A brief market-deregulation scheme saw electricity prices spike an average of over 30 per cent in just seven months. The government of the day was forced to cap prices for residential and small business owners — an unsustainable policy. The cap just masked the underlying problem of rising cost pressures in an electricity system in need of renewal and additional supply.

Ontario was also heavily reliant on coal-fired generation. About 25 per cent of electricity generation came from polluting coal-fired plants. In addition, Ontario imported coal power from neighbouring American states. Ontario, a province with ample power resources, had become a net importer of power.

Ontario Electricity Accomplishments 2003-2010

After taking office in 2003, the Ontario government faced a number of challenges including: a shortfall in supply, a system reliant on dirty coal-fired generation, a lack of conservation programs, an unsustainable pricing regime and little long-term planning.

The shortfall in supply was restored with investments of over $10 billion to keep the lights on in the province's homes and businesses. Since 2003, about 8,400 megawatts (MW) of new cleaner power have come on line — over 20 per cent of current capacity. That's enough electricity to power cities the size of Ottawa and Toronto. Ontario completed the return to service of Pickering A Unit 1 and enabled hydro and other renewable projects. The province also invested $7 billion to improve some 5,000 kilometres of transmission and distribution lines — the equivalent of the distance between Toronto and Whitehorse, Yukon.

Ontario's power has become cleaner by shutting down coal-fired generation and investing in renewables. In 2005, the government permanently shut-down the Lakeview coal-fired plant in Mississauga — the equivalent of taking 500,000 cars off the road. The province is on track to phase out coal-fired electricity by 2014, the largest climate change initiative of its kind in North America.

Currently, Ontario is Canada's solar and wind power leader, and home to the four largest operating wind and solar farms in the country. The province is developing a smart electricity grid that will help integrate the thousands of megawatts of new renewable power from these projects and others.

Public conservation programs were reintroduced to Ontario in 2005 to encourage and provide incentives for families, businesses and industry to consume less energy. Conservation is now a cornerstone of long-term electricity planning, recognizing that all Ontarians — for generations to come — will benefit from cleaner air and a lower carbon footprint.

In 2004, the government introduced a stable pricing regime that better reflected the true cost of electricity in Ontario. As a result, in 2005 the Ontario Energy Board (OEB) released a Regulated Price Plan, which brought predictability to electricity prices for residential and small business consumers. The OEB updates rates and adjusts prices every six months to reflect the costs of supply for that period.

Ontario has also taken steps to lower the stranded debt left by the previous government. Since 2003, Ontario has decreased the stranded debt by $5.7 billion.

In 2004, the government established the Ontario Power Authority (OPA) as the province's long-term energy planner. That set into motion a planning process that would ensure that Ontario's energy infrastructure would continue to be modernized. In 2007, the OPA prepared a 20-year energy plan (formally known as the Integrated Power System Plan or IPSP). The 2007 Plan focused on creating a sustainable energy supply, targeted to improving current natural gas and renewable assets at a sustainable and realistic cost. The government has made significant progress on the items outlined in the 2007 Plan.

2007 Plan Goal/ Target	Accomplishments
Ensure adequate supply	Invested over $10-billion to bring about 8,400 MW of new supply online — enough capacity to meet the annual requirements of 2 million households.
Double the amount of renewable supply (to 15,700 MW by 2025)	More than 1,500 MW of clean, renewable energy online since 2003, enough power for more than 400,000 homes.
Reduce demand by 6,300 MW by 2025.	More than 1,700 MW of conservation (reduction in demand) since 2005, equivalent to more than 500,000 homes being taken off the grid.
Replace coal in the earliest practical time frame	Phasing out coal-fired generation by 2014 Four units closed in 2010, ahead of schedule.
Strengthen the transmission system	Over $7 billion in investments since 2003 — upgrades to more than 5,000 kilometres of wires Moved forward on transmission projects to enable additional renewables; import potential; and refurbished nuclear generation
Ensure stable energy prices for Ontarians	The Regulated Price Plan introduced in 2005 has provided predictability Electricity prices have increased on average by about 4.5 percent per year over the past seven years Introduced energy tax credits to help residential and small business consumers with electricity costs

In 2009, the government introduced the groundbreaking Green Energy and Green Economy Act, 2009 (GEA). The GEA is sparking growth in clean and renewable sources of energy such as wind, solar, hydro, and bioenergy. A series of conservation measures in the GEA are providing incentives to lower energy use. In its first three years, the GEA will help create 50,000 clean energy jobs across the province. A clean-energy manufacturing base has been growing in the province and creating jobs for Ontarians.

Ontario's Energy Future 2010-2030

The priorities that the government sets and the investments the government makes today are laying the groundwork for an Ontario of tomorrow that will feature a modern, clean and globally competitive economy; healthy, vibrant and liveable communities; and an exceptional quality of life for all Ontarians. The government has a responsibility to ensure a clean, modern and reliable system for the health and well-being of Ontario families and businesses.

By 2030, Ontario's population is expected to rise about 28 per cent — a gain of almost 3.7 million people. Ontario's population will become more urbanized with population growth taking place in primarily urban areas. The Greater Toronto Area (GTA) population will increase by almost 38 per cent over the same period.

The overall composition of the economy will evolve as high-tech and service industries grow and manufacturers change how they do business to keep pace with technological advances and global competition. The output of large industrial customers, which accounts for about 20 per cent of electricity demand, is expected to grow moderately.

Getting around will be easier for all Ontarians. Improved regional and local transit systems that form integrated transportation networks will make it easy to travel, both within and between urban centres. There will be more electric cars on the road — Ontario's goal is that by 2020, about one in every 20 vehicles on the road will be electric.

All of this means that Ontario needs a more modern energy system and a diverse supply mix. Clean, reliable energy is the fuel that will power Ontario's future economic prosperity. Ontario must take steps today to ensure that the right kind of energy will continue to be there for us tomorrow.

Ontario is building a culture of conservation and as a result, it is expected that the province's demand for energy will grow only moderately over the next 20 years. Increased demand in the long term will be due to the rising population, industrial growth and increased use of electrical appliances and vehicles.

The Smart House of the Future

A smarter electricity grid will enable Smart Houses in the future by using technologies that have built-in intelligence. With Smart Grid infrastructure, homes will be able to use power when it is least expensive, charge electric vehicles, generate their own power via solar panels or other generation – and all of this can be controlled by the owner online, or by smart phone.

The Plan

Since the 2007 Plan, developments in technology, trends in demographics, changes in the economy and the advancements of the renewable energy sector (the success of the Feed-in-Tariff program) mean that Ontario needs an updated plan. This updated long-term energy plan will help to ensure that Ontario can meet the needs of an evolving economy and shifting electricity demands, while providing affordable electricity.

Currently, Ontario's electricity system has a capacity of approximately 35,000 MW of power. The OPA forecasts that more than 15,000 MW will need to be renewed, replaced or added by 2030. Because of capacity brought online in recent years, Ontario has some flexibility moving forward. The challenge is in choosing the right mix of generation sources and the necessary level of investment to modernize Ontario's energy infrastructure to meet future needs.

Through initiatives already underway, the province will be able to reliably meet electricity demand through 2015. Ontario needs to plan now for improving the power supply capacity to meet the province's electricity needs beyond 2015. Ontario must plan in advance because:

- Insufficient investment between 1995 and 2003 left an aging supply network and little new generation
- Additional clean generation will be needed to ensure a coal-free supply mix after 2014
- Nuclear generators will need to go offline while they are being modernized
- The population is projected to grow.

To meet these needs Ontario will need a diverse supply mix. Each type of generation has a role in meeting overall system needs. Ontario requires the right combination of assets to ensure a balanced supply mix that is reliable, modern, clean and cost-effective. Ontario will also, first and foremost, make the best use of its existing assets to upgrade, expand or convert facilities.

As part of a reliable network, the system needs both small and large generators. Nuclear power will continue to reliably supply about 50 per cent of the province's electricity needs. It does not emit air pollutants or emissions during production. Hydroelectric power is expanding to include increased capacity from the Niagara Tunnel project and the Lower Mattagami project — producing clean energy by tapping into a renewable and free fuel source. Natural gas-fired plants have the flexibility to respond when demand is high — acting as peak source or cushion for the electricity system. Natural gas is the cleanest of the fossil fuels, emitting less than half of the carbon dioxide emitted by coal.

Ontario is also planning for future energy generation that will focus on efficient, localized generation from smaller, cleaner sources of electricity rather than exclusively from large, centralized power plants transmitting power over long distances. This strategy is known as "distributed generation". Distributed generation also opens up opportunities for smaller power producers, allowing individuals, Aboriginal communities and small co-operatives or partnerships to become generators.

Renewable energy—wind, solar, hydro, and bioenergy — is an important part of the supply mix. Once the initial investment is made in equipment and infrastructure, fuel cost and greenhouse gas emissions are zero or very low. Renewable energy makes it possible to generate electricity in urban and rural areas where it was not feasible before.

In developing this report, the government heard from over 2,500 Ontarians (individuals, energy organizations, community representatives, and First Nation and Métis leaders and groups). Their views have helped to inform this report. In addition, the Ontario Power Authority (OPA), Hydro One, Ontario Power Generation (OPG), the Ontario Energy Board (OEB) and the Independent Electricity System Operator (IESO) contributed information and advice.

Ontario's Long-Term Energy Plan will help guide the province as it continues to build a clean, modern, and reliable electricity system for Ontario families now and well into the future. It will ensure Ontario continues to be a North American leader for clean energy jobs and technology and becomes coal-free by 2014. Key features of the plan include:

- Demand will grow moderately (about 15 per cent) between 2010 and 2030.
- Ontario will be coal-free by 2014. Eliminating coal-fired generation from Ontario's supply mix will account for the majority of the government's greenhouse gas reduction target by 2014. Two units at the Thunder Bay coal plant will be converted to gas and Atikokan will be converted to biomass. Two additional units at Nanticoke will be shut down in 2011.
- The government is committed to clean, reliable nuclear power remaining at approximately 50 per cent of the province's electricity supply. To do so, units at the Darlington and Bruce sites will need to be modernized and the province will need two new nuclear units at Darlington. Investing in refurbishment and extending the life of the Pickering B station until 2020 will provide good value for Ontarians.
- Ontario will continue to grow its hydroelectric capacity with a target of 9,000 MW. This will be achieved through new facilities and through significant investments to maximize the use of Ontario's existing facilities.
- Ontario's target for clean, renewable energy from wind, solar and bioenergy is 10,700 MW by 2018 (excluding hydroelectric) – accommodated through transmission expansion and maximizing the use of the existing system. Ontario will continue to grow the clean energy economy through the continuation of FIT and microFIT programs.
- Natural gas generation for peak needs will be of value where it can address local and system reliability issues. Natural gas will support the increase in renewable sources over time and supplement the modernization of nuclear generators.
- Combined Heat and Power is an energy-efficient source of power and the OPA will develop a standard offer program for projects under 20 MW.
- Ontario will proceed with five priority transmission projects needed immediately for reliability, renewable energy growth, and changing demand. Future Plans will identify more projects as they are needed.
- Ontario is a leader in conservation and the government will continue to increase and broaden its targets to 7,100 MW and reduce overall demand by 28 terawatt-hours (TWh) by 2030.
- Over the next 20 years, estimated capital investments totalling $87 billion will help ensure that Ontario has a clean, modern and reliable electricity system.
- Measures outlined in this Plan will help create and sustain jobs and investments in Ontario's growing clean energy economy.
- Residential bills are expected to rise by 3.5 per cent per year over the next 20 years. Industrial prices are expected to rise by 2.7 per cent per year over the next 20 years.
- The government is proposing an Ontario Clean Energy Benefit to give Ontario families, farms and small businesses a 10 per cent benefit on their electricity bills for five years.

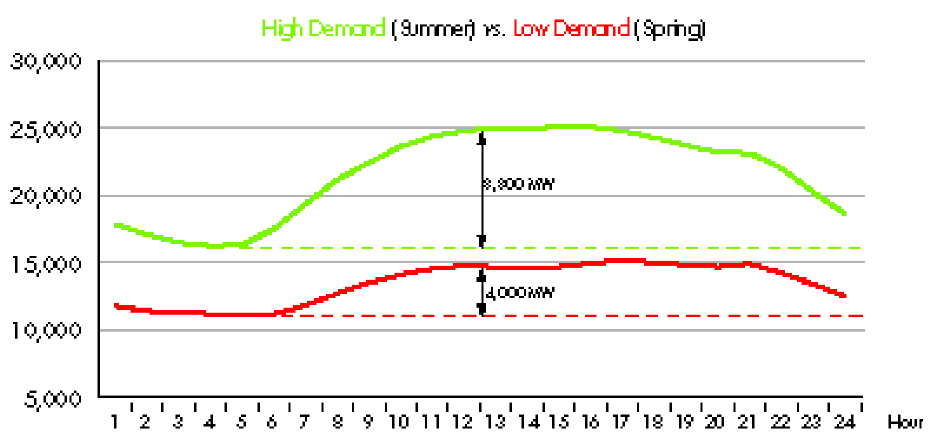
This plan will help ensure that Ontario is able to meet its electricity needs until 2030 and build a modern, clean, reliable system that will provide energy to Ontario homes and businesses for generations to come.

1 demand – an updated forecast

A forecast of the demand for electricity establishes the context for long-term planning — it predicts the amount of electricity Ontario will need.

System planning requires a complex forecast of the total amount of electricity that will be used over the course of a year, as well as the amount required to meet peak demand. The next step is to match these requirements with available generation and transmission capacity. Demand fluctuates with the time of day, weather, time of year and the structure of the economy. Ontario's demand can fluctuate between 11,000 MW on an early Sunday morning in spring to 25,000 MW on a hot Thursday afternoon in summer.

FIGURE 1: ONTARIO ELECTRICITY DEMAND COMPARISON



Unlike other forms of energy, electricity cannot be easily stored. Ontario's electricity system must be able to produce and move enough electricity to meet the changing demand for it instantaneously — all day and all night, every day and every night.

Ontario is part of an interconnected grid consisting of thousands of generators linked by tens of thousands of kilometres of transmission lines, crossing international, provincial and regional borders. The interconnected nature of the grid, supported by mandatory reliability standards, helps to ensure a stable power supply even when major components fail or when demand exceeds what can be met with domestic resources. Trade in electricity takes place over this interconnected system — for instance, between Ontario, Quebec and the U.S. — on a daily basis. In 2003, Ontario was a net importer and much of this imported supply came from U.S. coal power, which increased prices and reduced Ontario's air quality. Ontario is now a net exporter of electricity.

Electricity demand in Ontario has declined since reaching a peak in 2005. For the next 10 years, demand is expected to recover from the recent recession and then stay relatively flat as conservation efforts and an evolving economy change Ontario's energy needs.

Accomplishments

Ontario families and businesses have participated in conserving energy through various government conservation programs and shifting the demand away from peak hours.

- Ontario's conservation initiatives have been successful. Since 2005, Ontarians have saved enough energy to meet the combined electricity demand of Mississauga and Windsor.
- peaksaver®, a residential and small business electricity demand reduction program that temporarily powers down central air conditioning systems, has conserved enough to power a community the size of Thunder Bay.

Future Needs

Demand is recovering slowly in 2010 after the global economic recession. Future demand will depend on a number of factors including: the speed of Ontario's economic recovery, population and household growth, greater use of electronics in appliances and home entertainment systems, the pace of the recovery of large, energy-intensive industry and the composition of the economy (e.g. a shift to more high-tech and service jobs). Demand will also be impacted by the success of conservation efforts, as well as the potential electrification of public transit and the number of electric vehicles on the road. Weather can also have a pronounced effect.

To account for generation maintenance, extreme weather or significant changes in the amount of electricity the province needs, it is important to have electricity capacity in reserve.

The Plan

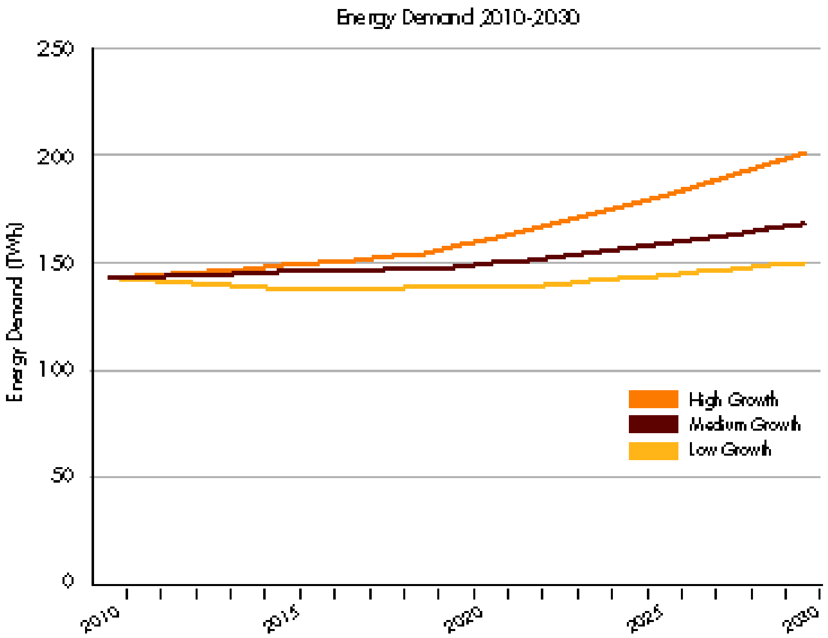
Based on OPA analysis, this Plan outlines three potential scenarios (net of conservation) for electricity demand:

1. Low growth (yellow) assumes that Ontario's manufacturing and industrial sectors continue to grow modestly in accordance with the current trend. Some of the recent decline in consumption is due to conservation, some to restructuring in the various industrial sectors, and some due to the recession. This forecast assumes a lower rate of population growth than in the other two scenarios. It further assumes that only 13 per cent of people use electricity for heating and that small appliance use accounts for 30 per cent of growth.

2. Medium growth (brown) represents moderate growth in the industrial sector and in population. This scenario assumes continued growth in the residential, commercial and transportation sectors. This forecast assumes that there is a consistent move towards high-tech and service industries and somewhat higher provincial population growth than the low growth scenario. This scenario is consistent with the current government goal for electric vehicles: five per cent by 2020.

3. High growth (orange), or aggressive electrification, assumes that there is a significant increase in electric transportation — both public and private. It assumes that there is aggressive North American greenhouse gas regulation, faster population growth than the low growth scenario, significant industrial change and that by 2030 about 12 per cent of vehicles on the road are electric.

FIGURE 2: RANGE OF ENERGY DEMAND FORECAST



The three scenarios do not differ significantly until 2018, allowing time to adjust as the Long-Term Energy Plan will be updated every three years. For planning purposes, the government is using the medium growth line to predict future electricity needs. The medium growth scenario balances the expected growth in residential and commercial sectors, with modest, post-recession growth in the industrial sector. The addition of 1.1 million households and the expected increase in the use of entertainment electronics, and small appliances will increase residential electricity demand. The addition of 132 million square metres of commercial space and the associated use of air-conditioning, lighting and ventilation will increase electricity demand in the commercial sector.

Based on the medium growth scenario, Ontario's demand will grow moderately (15 per cent) between 2010 and 2030, based on the projected increase in population and conservation as well as shifts in industrial and commercial needs. As a result, for planning purposes, the system should be prepared to provide 146 TWh of generation in 2015 rising to 165 TWh in 2030.

Ontario is also planning to create sufficient flexibility in the system to accommodate the higher growth scenario.

2 supply

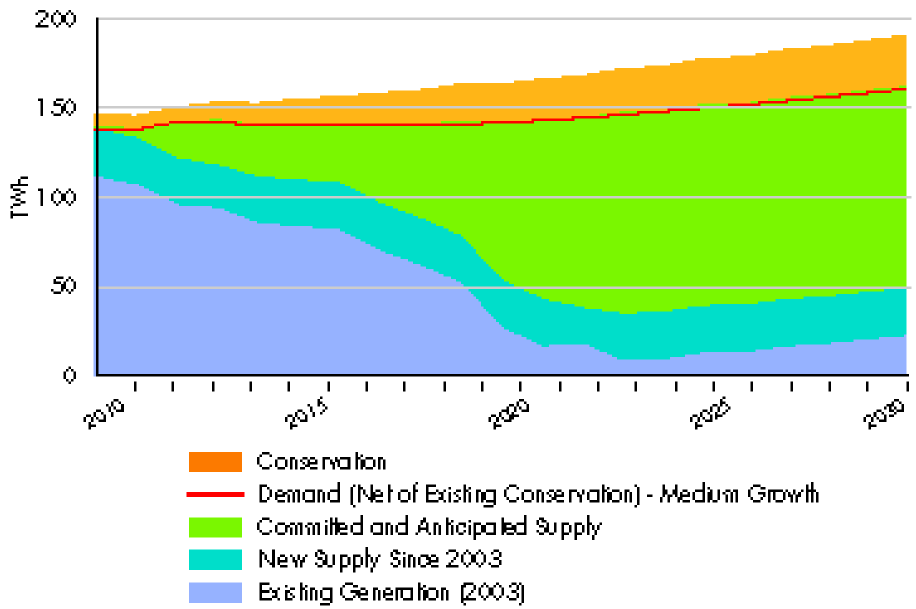
With a long-term demand forecast in place, Ontario must determine the most effective way to meet that demand so that there is no gap in supply. Ontario needs a balanced, cost-effective supply mix that supports the economy, is modern, can adapt to future changes and provides clean, reliable electricity to Ontario families and businesses for generations to come.

A clean, reliable energy system relies on a balance of resources. Good system planning includes a sustainable supply mix that meets the demands of the public. It also means continually looking for efficiencies and emphasizing the best use of current resources. Ontario's supply mix includes:

- Conservation: As the best and first resource, it reduces consumption and therefore demand on the system. By avoiding the need to build new generation, all consumers benefit through cost savings.
- Baseload power: Generation sources, such as nuclear and hydro stations, designed to continuously operate (Niagara Falls, for example). Baseload power is the foundation of a stable, secure supply mix.
- Variable or intermittent power: Generation sources that produce power only during certain times such as wind and solar projects. These are important contributors to a cleaner supply mix.
- Intermediate and peak power: Generation sources designed to ramp up and down as demand changes throughout the day such as natural gas and hydro generation with some storage capability. These function as a cushion to the system to ensure reliability when demand is highest.

This supply mix balances reliability, cost and environmental performance.

FIGURE 3: FORECAST SUPPLY AND DEMAND (2010-2030)

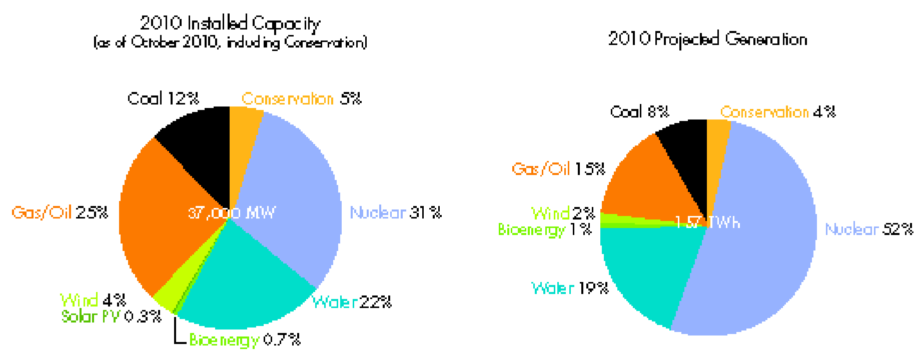


Energy Storage can help to balance the electricity grid by storing off-peak generation and using it during peak hours. This helps to reliably incorporate more renewable generation into the grid. Energy storage is an important part of the move to a Smart Grid. Ontario will continue to investigate the potential for new storage technologies. There are a number of issues that impact the development of energy storage:

- The capital costs for large-scale electricity storage are high largely due to high engineering and construction costs.
- Research is underway on flywheel storage, plug-in vehicle storage, various forms of thermal storage as well as other storage options.
- There are growing opportunities for small storage projects, particularly as battery technology improves.
- Ontario has a pumped storage facility in the Sir Adam Beck Pumping Generating Station at Niagara Falls. OPG is currently studying the possible expansion of the reservoir to allow for further storage at the station.

The capacity of the system is necessarily larger than what is actually generated. It is critical to have more capacity than generation to be able to manage normal equipment maintenance and shutdowns, unprecedented peak demands or an unexpected shutdown of an electricity generator. Generation, or the amount of electricity Ontario produces, is measured in terawatt hours (TWh or billion kWh). The capacity of the system, or what it is able to generate, is measured in megawatts (MW).

FIGURE 4:
CONTRAST BETWEEN GENERATION AND INSTALLED CAPACITY



Selecting a supply mix and investment in supply is a matter of choices and trade-offs. A variety of power supply sources — some designed for baseload requirements, some designed for meeting peak requirements — is superior to relying heavily on only one source. For this long-term plan the government has considered environmental, economic, health, social and cost implications to come up with the best possible supply mix.

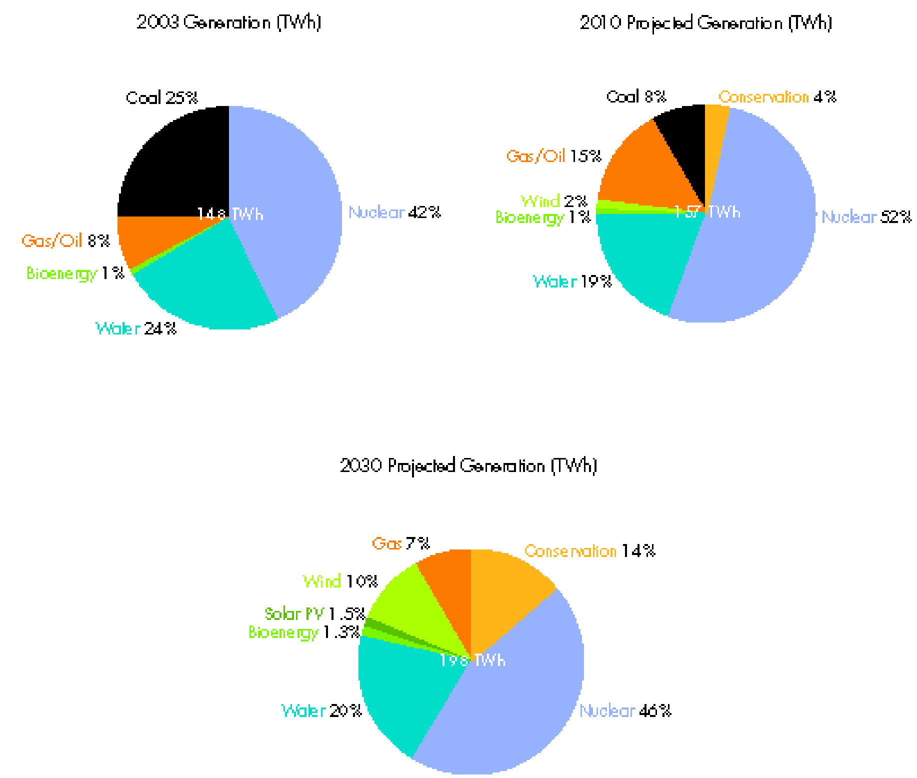
This improved supply mix will be cleaner, sustainable, modern and reliable. It phases out coal-fired generation at a faster pace, it modernizes Ontario's nuclear fleet, it includes more renewables, it maximizes hydroelectric power over the near term, and it advances Ontario's conservation goals.

By 2030, Ontario will have completely eliminated coal as a generation source and will have also increased wind, solar and bioenergy from less than one per cent of generation capacity in 2003 to almost 13 per cent. To ensure reliability, the strategic use of natural gas will be required to complement renewable generation. Nuclear will continue to supply about 50 per cent of Ontario's electricity needs.

The following chapter will include a review of the various components of Ontario's electricity supply:

- Coal
- Nuclear
- Renewables: Hydroelectric
- Renewables: Wind, Solar and Bioenergy
- Natural gas
- Combined Heat and Power (CHP)

FIGURE 5: BUILDING A CLEANER ELECTRICITY SYSTEM



Coal Free

The Ontario government is committed to improving the health of Ontarians and fighting climate change. Coal-fired plants have been the single largest source of greenhouse gas emissions in the province and among the largest emitters of smog-causing pollutants. Ontario's reliance on coal-fired generation shot up 127 per cent from 1995-2003, significantly polluting the province's air. During that period Ontario also relied on importing coal-fired power from the United States. An Ontario study found the health and environmental costs of coal at $3 billion annually ("Cost Benefit Analysis: Replacing Ontario's Coal-Fired Electricity Generation," April 2005).

Since 2003, the government has reduced the use of dirty coal-fired plants by 70 per cent. Eliminating coal-fired electricity generation will account for the majority of Ontario's greenhouse gas reduction target by 2014 — the equivalent of taking 7 million cars off the road.

In addition, Ontario Power Generation (OPG) is required to meet strict government-mandated greenhouse gas emission targets, including ensuring that between 2011 and 2014 annual emissions are two-thirds lower than 2003 levels.

Ontario is the only jurisdiction in North America that is phasing out coal-fired generation. The government has committed to eliminating coal-fired generation by 2014 and is introducing clean and reliable sources of energy in its place. Until then, coal and natural gas plants will continue to provide power in peak-demand periods to maintain the reliability of the system.

Accomplishments

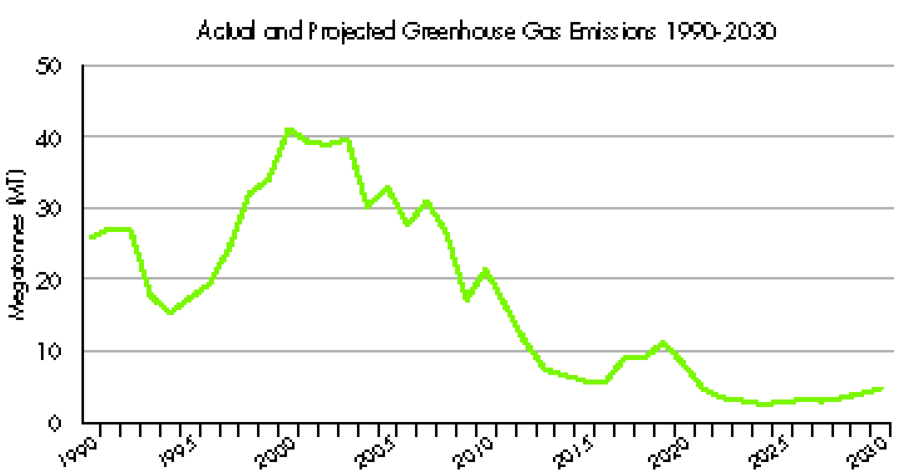
The government of Ontario has shut down eight coal units since 2003 (3,000 MW) and will close the remaining units by 2014 or earlier.

- Lakeview (Mississauga) – four units closed April, 2005
- Nanticoke – two units closed October, 2010
- Lambton – two units closed October, 2010

After the closure of four coal units on October 1, 2010, coal-fired generation makes up only 13 per cent of Ontario's electricity capacity.

Ontario's electricity sector emissions will decrease dramatically to only five megatonnes post-2020 as a result of becoming coal-free. Between 2015 and 2019, extensive nuclear refurbishments will take place and Ontario will rely on its natural gas-fired stations to maintain reliable electricity supply.

FIGURE 6:
REDUCING EMISSIONS IN ONTARIO'S ELECTRICITY SECTOR



The Plan

Coal-fired plants will cease to burn coal in 2014. Ontario will shut down two additional units at Nanticoke Generating Station before the end of 2011.

The government recognizes the potential benefits of continuing to use Ontario's existing electricity-generating assets and sites. Coal-fired plants could be converted to use alternative fuels, such as natural gas. Similar to coal, biomass and/or natural gas can provide electricity on demand for peak periods.

In line with the Growth Plan for Northern Ontario and future needs of the Ring of Fire, the province is replacing coal at Atikokan and Thunder Bay and re-powering these facilities with cleaner fuel sources.

Converting the Atikokan Generating Station to biomass by 2013 will create up to 200 construction jobs and help protect jobs at the plant. It will also support jobs in Ontario related to the production of wood pellets and sustain other jobs in the forestry sector. The project is expected to take up to three years to complete. Once converted, the plant is expected to generate 150 million kilowatt-hours of renewable power, enough to power 15,000 homes each year.

At the Thunder Bay Generating Station, two units will be converted to natural gas in a similar timeframe. The Thunder Bay plant is needed not only for local supply to the city of Thunder Bay, but for system reliability in northwestern Ontario, particularly during periods of low hydroelectric generation and until the proposed enhancement to the East-West tie enters operation. The government will work with suppliers on the planning process to convert the Thunder Bay units.

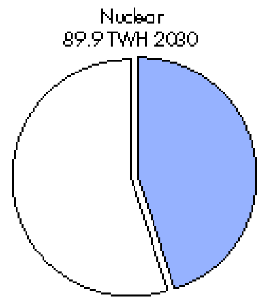
Ontario will continue to explore accelerating the closure of the remaining six units (four at Nanticoke and two at Lambton), taking into consideration the impact of the closures on system reliability.

Ontario will monitor the progress of the continued operation of nuclear units at Pickering. The government expects in 2012 to have an update on the progress of extending the life of these units. At this time, Ontario will consider the possible conversion of some of the units at Nanticoke and Lambton to natural gas, if necessary for system reliability. Due to the lead times involved, planning and approval work for the natural gas pipeline infrastructure required to Nanticoke will begin soon.

Ontario will continue to explore opportunities for co-firing of biomass with natural gas for any units converted to natural gas. Decisions on other biomass opportunities will have to carefully take into account the ability to bring in fuel supply and the cost of conversion.

Nuclear – New/Modernized

Nuclear power is a reliable, safe supplier of the province's baseload generation needs — accounting for about 36 per cent of the province's installed electricity capacity. Nuclear operates 24 hours a day, seven days a week and it produces about 50 per cent of the electricity generated in Ontario. Nuclear power does not produce any primary air pollution or release greenhouse gases into the atmosphere.



Nuclear power plants are able to operate steadily, providing a plentiful, consistent supply of energy for decades at stable prices. In addition, the fuel cost for a nuclear power plant is a small portion of its total costs, so nuclear power is generally not impacted by fuel price escalation or fluctuations.

- Ontario has used nuclear power for more than 40 years.
- In 2009, more than half of the province's electricity came from nuclear energy.
- Ontario's nuclear power stations and waste storage facilities have an excellent safety record. OPG won the Zeroquest Platinum (Sustainability) Award from the Infrastructure Health and Safety Association (IHSA) in June 2010.
- Over 70,000 jobs in Canada are directly or indirectly related to the nuclear power industry.

Accomplishments

A number of nuclear power producing units have been modernized and returned to service since 2003 including:

- Pickering A Unit 1, in November 2005, providing 515 MW (or about 6 per cent of new supply)
- Bruce Unit 3, in March 2004, providing 770 MW (or about 9 per cent of new supply)
- Bruce Unit 4, in November 2003, providing 770 MW (or about 9 per cent of new supply)

Future Needs

Nuclear power is crucial to providing reliable electricity to the province. Units at Bruce B and Darlington are expected to reach the end of their service lives over the next decade. To extend the life of these units, each would have to be shut down for about three years while being modernized.

At the time of the 2007 Plan, there was a need for new nuclear planning to begin immediately. Since then, demand has declined and renewable generation has become a bigger contributor to the system. Investment in renewables, the reduction in demand and the availability of natural gas have all reduced the immediate need for new nuclear. However, to preserve the long-term reliability of the system, particularly for baseload generation, additional investment in nuclear generation will be required.

Ontario will continue to rely on nuclear power – at its current level of contribution to the supply. Nuclear generation is ideally suited for providing baseload generation because of its unique economic and operating characteristics. Nuclear plant operational design and economics depend on the plants being able to operate steadily throughout the year. A generation mix of 50 per cent nuclear combined with baseload hydroelectric generation is sufficient to meet most of Ontario's baseload requirements.

If nuclear capacity beyond this were added, the hours in the year in which nuclear capability exceeded Ontario demand could substantially increase. Under such surplus conditions, some nuclear units might need to be shut down or operate differently than intended. This could lead to significant system and operating challenges and so therefore, generating too much nuclear is undesirable.

The Plan

Over the first 10 to 15 years of this Plan, 10,000 MW of existing nuclear capacity will be refurbished. Investment should focus first and foremost on the improvement of existing assets so that those facilities can continue to provide reliable, affordable electricity. A coordinated refurbishment schedule was agreed to in 2009 by a working group including OPG, Bruce Power, the OPA and the Ministry of Energy. This schedule will be regularly reviewed and updated to reflect current information on resources and plant performance and conditions.

The government is committed to continuing to use nuclear for about 50 per cent of Ontario's energy supply — a capacity of 12,000 MW will produce that amount of energy. The remaining nuclear capacity of 10,000 MW at Darlington and Bruce will need to be refurbished and modernized.

The remainder of the nuclear capacity that Ontario will need for its projected demand (about 2,000 MW) will be made up of new nuclear at Darlington.

The construction of new nuclear infrastructure requires a significant lead time (approximately 8 to 10 years to commercial operation) and while new nuclear supply will be needed in Ontario, it must be provided at a fair price to ratepayers. Both refurbishment and new build will have significant positive impacts on local economies – and considerable employment opportunities.

In February 2008, the government of Ontario launched a process to procure two new units at the Darlington site. Atomic Energy of Canada Limited (AECL) was one of three vendors who met the February 2009 bid submission deadline. AECL emerged as the only compliant bidder in the process; however the AECL bid price exceeded the province's target. Ontario then sought to finalize a deal with the company to procure the units at an acceptable price.

During the discussions between the Ontario government and the federal government, the federal government announced its intention to sell AECL in May 2009. The news cast a great deal of uncertainty over Ontario's procurement process. The position of uncertainty that the federal government placed AECL in, together with a much higher than anticipated price, made it very difficult for Ontario to finalize a procurement that was in the best interest of ratepayers. As a result, Ontario suspended the RFP process in June 2009.

The Province continued to engage AECL, as the only compliant bidder, in discussions with the hope that a deal could still be finalized. The talks did not lead to any demonstrable progress. Consequently, the Premier of Ontario wrote to the Prime Minister requesting that the process to sell AECL be halted. It was Ontario's position that both levels of government should try to complete the procurement with AECL before the company was sold so that Ontario's need for significant nuclear refurbishment and new nuclear generation could be met while simultaneously protecting jobs and preserving the industry in Canada. This proposal was not pursued by the federal government and their process is continuing without a deal with Ontario being completed.

It is anticipated that the federal government will identify a preferred vendor by the end of this year. Ontario is expecting that the federal government will restructure AECL in a manner that will allow Ontario to be able to complete a deal with the new owner at a price that is in the best interest of ratepayers.

The decrease in demand together with the new supply added in recent years, means that Ontario is well-positioned to examine a number of options for negotiating new nuclear production at the right time and at a cost-effective price.

In the meantime, OPG is continuing with two initiatives that were underway prior to the suspension of the new build procurement process: the environmental assessment and obtaining a site preparation licence at Darlington. It is essential that the province stay ready to construct new nuclear plants as part of the government's ongoing commitment to modernize Ontario's nuclear fleet.

OPG will invest $300 million to ensure the continued safe and reliable performance of its Pickering B station for approximately 10 years, to 2020. Following this, OPG will begin the longer term decommissioning process and will work with the community of Pickering and the advisory committee to explore future opportunities for the site.

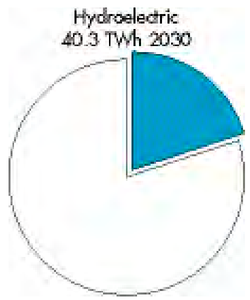
A 2010 report by the Canadian Manufacturers and Exporters estimates the employment and economic benefits from refurbishing and operating the Bruce and Darlington reactors will be substantial: almost 25,000 jobs and annual economic activity of $5 billion.

In developing a new-build procurement and modernization strategy Ontario will:

- Secure an acceptably priced contract for construction of nuclear new build under specified timeframes.
- Pursue project terms that are in the best interest of ratepayers.
- Retain the maximum number of high-quality, high-paying nuclear industry jobs in the province while providing opportunities for long-term growth of the nuclear industry.

Renewables: Hydroelectric

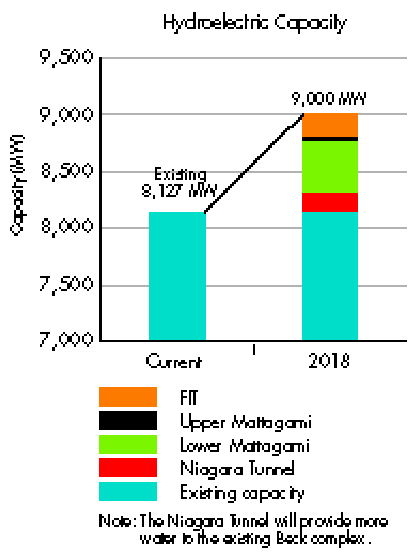
Ontario has been generating renewable power from water — hydroelectric power — for over 100 years. Hydroelectric power is clean, renewable, cost-effective and helps to contribute to clean air quality. Hydro currently makes up the vast bulk — about 90 per cent — of Ontario's total renewable energy supply, representing 8,127 MW of capacity. It is a reliable source of electricity that can continue to provide clean energy for generations to come.



Accomplishments

The 2007 Plan projected a total of 7,708 MW of hydroelectric capacity by 2010. The government has exceeded this goal. Ontario has also launched significant hydroelectric projects — the first major investments in 40 years. Since October 2003, 317 MW of new hydro projects have been brought online.

FIGURE 8: HYDROELECTRIC CAPACITY



Some of the larger completed and ongoing hydro projects to meet Ontario's future needs include:

- Niagara Tunnel project, which will increase the amount of water available for power generation at the Sir Adam Beck Generating Station
- The Lower Mattagami project expansion – the largest hydroelectric project undertaken in Ontario in 40 years. This project will add about 440 MW of clean electricity generating capacity to Ontario's energy grid, while providing $2.6 billion of investment in the North
- Healey Falls, a 15.7 MW facility near Campbellford, east of Peterborough
- Lac Seul Generating Station, a 12.5 MW facility near Ear Falls
- Trent Rapid Hydroelectric Station, an 8 MW facility near Peterborough
- Sandy Falls, a 5.5 MW facility on the Mattagami River, near Timmins.

Future need

More hydroelectric power will be added to Ontario's electricity system in the next eight years than over the previous 40 years. Unlike Quebec, Ontario does not have the geography to support massive reliance on hydroelectric power. (Quebec has almost four times the hydro capacity of Ontario.) New hydroelectric generation will continue to be an important part of a clean, reliable system over the next 20 years. The government is also reviewing how crown land is made available for waterpower projects, particularly for smaller Feed-InTariff (FIT) Program projects.

The Plan

Ontario will continue to develop the province's hydroelectric potential and is planning for 9,000 MW of hydroelectric capacity by 2018.

Once the Niagara Tunnel expansion is complete, it will provide enough electricity to power 160,000 homes. When the capacity expansion at Lower Mattagami is complete, the project will provide enough electricity to power over 300,000 homes. These projects will help to maximize Ontario's existing hydro projects.

Existing hydro is the cheapest form of generation in Ontario and in many cases, it can help to meet peak power demand. There are a number of projects that are currently under consideration, such as:

- Two hydroelectric generating stations on the Little Jackfish River (north of Lake Nipigon) that could add 100 MW of capacity
- New Post Creek, a 25 MW project in the development stage
- Mattagami Lake Dam, a 3-6 MW development at Kenogamissi Falls on the Mattagami River.

Ontario will plan for future hydroelectric development where it is cost-effective to build. This will mean FIT-level hydro projects (less than 50 MW) will also be considered.

New hydro projects complement other renewable initiatives and help to eliminate coal by 2014. Some additional projects will be considered, but large-scale projects, usually in remote locations, are not economically feasible at this time due to high capital and construction costs. Transmission, engineering and environmental factors are also challenges. However, due the importance of hydroelectric generation, Ontario will continue to study Northern hydro options over the period of the Plan.

Renewables: Wind, Solar and Bio-energy

Ontario has become a North American leader in producing energy from sources that are continually renewed by nature such as wind, sun and bioenergy. Renewables do not produce harmful emissions, which contribute to smog, pollution and climate change. Increasing Ontario's renewable energy supply helps reduce the province's reliance on fossil fuels. Greater investments and reliance on renewable energy help to ensure that Ontario has a clean and reliable electricity system for generations to come.

Accomplishments

Ontario is now Canada's leading province for wind and solar capacity and home to the country's four largest wind and solar farms. The world's largest photovoltaic solar farm is in Sarnia (Enbridge's 80 MW Sarnia Solar) and Canada's largest wind farm is near Shelburne (the 199.5 MW Melancthon EcoPower Centre). In 2003, Ontario had 10 wind turbines; today, the Province has more than 700.

Since October 2003, the government has signed more than 16,000 renewable energy supply contracts from wind, water, solar and bio-energy sources. This includes almost 2,400 MW of small and large renewable power projects under North America's first comprehensive Feed-in Tariff (FIT) Program, introduced in 2009. These FIT contracts represent a private sector investment of $9 billion and are projected to create approximately 20,000 direct and indirect clean energy jobs.

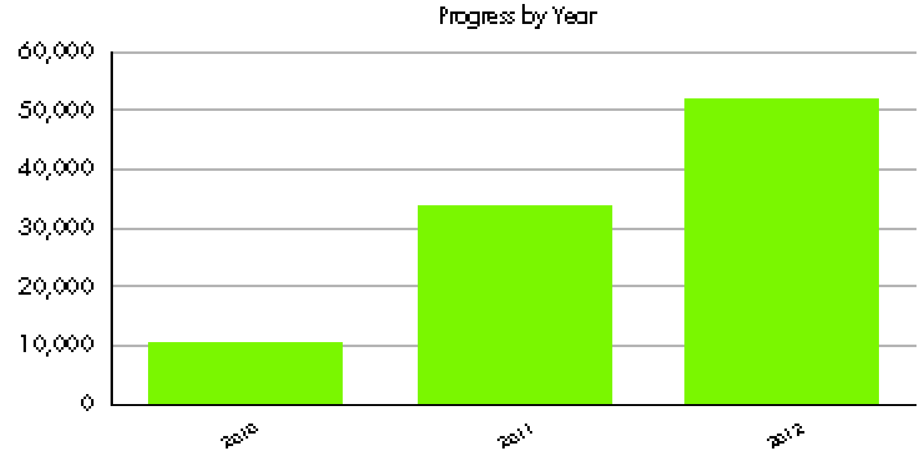
The success of the FIT Program has also attracted the notice of global investors, including a consortium of companies led by Samsung C&T Corporation, laying the foundation for Ontario to become a global clean energy production and manufacturing hub.

> Ontario's Feed-in Tariff (FIT) Program combines stable, attractive prices and long-term contracts for energy generated using renewable resources.
>
> Homeowners, business owners and developers may apply to the FIT Program if they use one or more forms of renewable energy, including wind, waterpower, solar photovoltaic (PV) power and bioenergy.
>
> The Program is the first comprehensive FIT program in North America. It was launched through the Green Energy and Green Economy Act, 2009.
>
> Over 1,000 FIT contracts are currently in place for clean energy projects.

Some 51 community projects will provide renewable electricity supply to the grid through the Ontario FIT program. From these projects, more than 200MW of clean electricity will be generated by communities engaging in, solar, wind and bio-energy projects across Ontario.

Thousands of Ontarians are also participating in the microFIT Program. Homeowners, farmers or small business owners, are able to develop a very small or "micro" renewable electricity generation project (10 kilowatts or less in size) on their properties. Under the microFIT program, they are paid a guaranteed price for all the electricity they produce for 20 years.

FIGURE 9: PROGRESS ON 50,000 PROJECTED GREEN ENERGY ACT JOBS



Major Private-Sector Renewable Investments in Ontario

The $7-billion Green Energy Investment Agreement with Samsung C&T Corporation and Korea Electric Power Corporation (Consortium), is the single largest investment in renewable energy in provincial history. It will:

- Build 2,500 MW of wind and solar power.
- Deliver an estimated 110 million megawatt-hours of emissions-free electricity over the 25-year lifetime of the project — enough to supply every Ontario home for nearly three years.
- Create more than 16,000 new clean energy jobs to supply, build, install and operate the renewable generation projects.
- Lay the groundwork with major partners to attract four manufacturing plants.

Out of the 16,000 new clean energy jobs, this investment is expected to create or sustain 1,440 manufacturing and related jobs, building wind and solar technology for use in Ontario and export across North America.

As part of the Green Energy Investment Agreement, Samsung and Siemens have announced plans to build Ontario's first wind turbine blade manufacturing plant, which will create up to 900 direct and indirect jobs. The Consortium will negotiate with manufacturing partners to locate three other plants in Ontario for wind turbine towers, solar inverters and solar module assembly.

Under the agreement, three of the four manufacturing facilities are scheduled to be ready in 2013, while the fourth is scheduled to be in operation by the end of 2015. The Consortium also intends to use Ontario-made steel and other Ontario content in its renewable energy projects for items such as wind turbine towers.

More than 20 companies have publicly announced plans to participate in Ontario's clean energy economy, in the last year. These companies are currently operating or plan to set up solar and wind manufacturing facilities in Ontario in the following categories: solar PV modules, mounting systems, inverters, wind turbine blades and wind turbine towers. Some recent examples include:

- Heliene Inc., producing modules in Sault Ste. Marie;
- Canadian Solar, will manufacture modules in Guelph;
- Photowatt, producing modules in Cambridge;
- Samco, an auto parts manufacturer now also producing solar mounting systems in Scarborough;
- Schletter, producing solar mounting systems in Windsor;
- Sustainable Energy Technologies partnering with Melitron to produce inverters in Guelph;
- Satcon, producing inverters in Burlington;
- Siemens will be producing wind turbine blades; and,
- DMI Industries is producing wind turbine towers in Fort Erie.

Future Needs

Ontario will continue to be a leader in renewable energy development and generation. The growth of the renewable energy sector will be influenced by electricity demand, the ability of the system to accommodate additions to the grid, continued innovation in the renewable technology sector and global demand for renewable energy production. Expansions and upgrades to the transmission and distribution system will be necessary to increase the capacity for renewable energy in Ontario.

As more and more of Ontario's electricity comes from renewable energy sources and research and innovation of Smart Grid technologies continues, there will be increased opportunities for renewable energy projects, both large and small to be established in Ontario.

There will also be greater opportunity for employment in this field. Renewable energy projects require skilled labour, such as engineers as well as construction and maintenance labour across the province. As renewable energy projects are established, the need for skilled and general labour will continue to provide jobs for thousands of Ontarians over the next decade. Innovation in new technology also contributes high skilled jobs and economic opportunities for Ontario.

> Biomass is dispatchable and can be used as a peaking resource. This attribute allows it to complement increased wind and solar generation. The conversion of Atikokan Generating Station to run on biomass will contribute to long-term system reliability, especially during low water conditions in the region. The conversion from coal to biomass at Atikokan by 2013 will create up to 200 construction jobs and help protect jobs at the plant. It will also support jobs in Ontario related to the production of wood pellets and sustain other jobs in the forestry sector. Ontario will continue to monitor the conversion of Atikokan and consider future potential of biomass generation.

The Plan

Ontario will continue to develop its renewable energy potential over the next decade. Based on the medium growth electricity demand outlook, a forecast of 10,700 MW of renewable capacity (wind, solar, and bioenergy) as part the supply mix by 2018 is anticipated. This forecast is based on planned transmission expansion, overall demand for electricity and the ability to integrate renewables into the system. This target will be equivalent to meeting the annual electricity requirements of two million homes.

The province's renewable energy capacity target will be met with the development of renewable energy projects from wind, solar, biogas, landfill gas and biomass projects across Ontario.

Future rounds of FIT projects will be connected to the Bruce to Milton transmission line and the priority transmission projects identified as part of this Long-Term Energy Plan. This will enable 4,000 MW of new renewable energy projects to be connected.

In the near term, the OPA will be releasing information regarding the status of all FIT applications not offered contracts as of June 4, 2010. These applications will be subject to the first Economic Connection Test (ECT) under the FIT program. The ECT process, to be conducted on a regular basis and in alignment with major planning or system development milestones, will help to determine whether the costs of grid upgrades to allow a FIT project to connect to the grid are economically viable.

For the period after 2018, depending on changes in demand, Ontario will look for opportunities to increase the development of renewable energy projects and expand renewable energy capacity in the Province. Ontario will review the electricity demand outlook in the next Long-Term Energy Plan to explore whether a higher renewables capacity forecast is required.

FIT contract prices were set following extensive consultations and are designed to ensure a reasonable rate of return for investors while providing good value for clean, renewable energy for Ontario ratepayers.

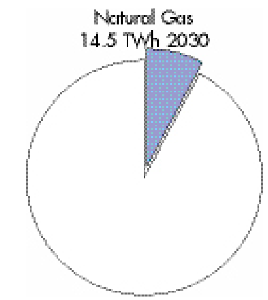
As part of the scheduled two-year review of the FIT Program in 2011, the FIT price of renewables in Ontario will be re-examined. Successful and sustainable FIT programs in a number of international jurisdictions (such as Germany, France and Denmark) have decreased price incentives. Advances in technology and economies of scale reduce the cost of production. A new price schedule will be carefully developed to achieve a balance between the interests of ratepayer and the encouragement of investment in new clean energy in Ontario.

The response to the microFIT and FIT programs has been a tremendous. Thousands of Ontarians are participating in the program to feed clean energy into the grid.

Given the popularity of Ontario's growing clean energy economy, applications to the microFIT and Capacity Allocation Exempt (CAE FIT) program are outpacing needed upgrades to the grid. To continue to ensure the growth of small clean energy projects, Ontario will continue to invest in upgrades to the transmission and distribution systems to accommodate renewable supply.

In areas where there are technical challenges, the OPA, Hydro One and Local Distribution Companies will continue to work with proponents that have already applied to the CAE FIT or microFIT program.

Natural Gas



Natural gas plants have the flexibility to respond well to changes in demand, making them an important cushion for Ontario's electricity system — particularly for peak periods.

Natural gas produces electricity either by burning to directly power a gas turbine or by producing steam to drive a steam turbine. A combined cycle gas plant combines these two technologies. Natural gas can supplement baseload power supply and, because it responds quickly to increases in demand, it can also complement the intermittent nature of wind and solar electricity generation.

Natural gas is much cleaner than coal. Some air emissions — particularly mercury and sulphur dioxide — are totally eliminated when natural gas replaces coal. Carbon dioxide emissions are reduced by between 40 and 60 per cent. Currently, Ontario's electricity generation capacity from natural gas is over 9,500 MW.

By replacing coal with natural gas and renewable energy sources, Ontario has greatly reduced greenhouse gas emissions from its electricity supply mix. This policy has prepared Ontario for the possibility of greenhouse gas regulation in the North American market.

Accomplishments

The Ontario government and the OPA have launched a number of clean natural gas and cogeneration projects since 2003 to help with local reliability and peak demand.

The 2007 Plan projected that some 12,000 MW of natural gas would be needed by 2015. Since then, changes in demand and supply — including about 8,400 MW of new, cleaner power across the system and successful conservation efforts — means that less capacity will be required.

Future Needs

In 2009, about 10 per cent of Ontario's electricity generation came from natural gas. In the coming years, the government anticipates that it will be necessary to maintain the amount of natural gas supply at its current level in the supply mix.

The Plan

Natural gas will continue to play a strategic role in Ontario's supply mix as it helps to:

- Support the intermittent supply from renewables like wind and solar
- Meet local and system reliability requirements
- Ensure adequate capacity is available as nuclear plants are being modernized

The 2007 Plan outlined a forecast need for an additional three gas plants in the Province, including one in the Kitchener-Waterloo-Cambridge and one in the southwest GTA.

Because of changes in demand along with the addition of approximately 8,400 MW of new supply since 2003, the outlook has changed and two of the three plants — including the proposed plant in Oakville — are no longer required. However, a transmission solution to maintain reliable supply in the southwest GTA will be required.

As indicated in 2007 Plan, the procurement of a peaking natural gas-fired plant in the Kitchener-Waterloo-Cambridge area is still necessary. In that region, demand is growing at more than twice the provincial rate.

Ontario is taking advantage of its existing assets with the conversion of two coal-fired units in Thunder Bay to natural gas. (See page 21 on Coal.)

Over the next few years, non-utility generation contracts, which were entered into between the private sector and the former Ontario Hydro in the early 1990s, will begin to expire. Many of these are natural gas-fired. These non-utility generators — or NUGs as they are known — have been part of Ontario's overall supply mix for 20 years. They can contribute up to 1,550 MW of clean power to the system. The contracts with NUGs are currently held by the Ontario Electricity Financial Corporation, an agency of the Ministry of Finance.

As non-utility generator contracts expire, the IESO and the OPA will determine if the generation is still required to help ensure reliability. The government will direct the OPA to design contracts that will encourage NUGs to operate during periods when it would most benefit the electricity system. The OPA will be authorized to enter into new contracts where this generation is needed and will negotiate to get the best value for consumers.

CHP (Combined Heat and Power/Cogeneration)

Combined Heat and Power is the simultaneous production of electricity and heat using a single fuel such as natural gas. The heat produced from the electricity generation process is captured and used to produce steam or hot water that can then be used for industrial and commercial heating or cooling purposes, such as district energy systems.

CHP can make more efficient use of fuel and therefore reduce greenhouse gas emissions. CHP overall efficiency can exceed 80 per cent — which means that 80 per cent of the energy can be captured as electricity or usable heat.

Accomplishments

Currently, the total industrial CHP capacity in Ontario is estimated to be about 2,000 MW, or about 6 per cent of Ontario's installed generation capacity.

In October 2006, the OPA awarded seven contracts with a total capacity of 414 MW — enough to provide the power for 400,000 Ontario homes. Much of this new capacity (395 MW) will be coming from industrial projects. These facilities are in communities across the province including: Windsor, Kingsville, London, Oshawa, Markham, Sault Ste. Marie and Thorold.

Algoma Energy Cogeneration Facility

The 63 MW Algoma Energy Cogeneration Facility is located in Sault Ste. Marie, Ontario. The facility uses the by-product fuels from cokemaking and ironmaking (blast furnace and coke oven gas) to generate electricity and steam used for steel manufacturing operations.

The facility reduces Essar Steel Algoma's reliance on the provincial power grid by 50 per cent on average, freeing up this capacity for the rest of the province. This cogeneration facility helps to reduce Essar Steel Algoma's nitrous oxide emissions by 15 per cent (approximately 400 metric tonnes a year).

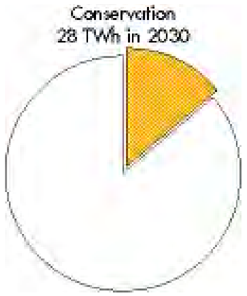
The Plan

Ontario will target a total of 1,000 MW of CHP. It will be procured through the OPA and will include existing contracts, individual negotiations for large projects and a new standard offer program for smaller projects in key strategic locations.

The government will encourage new local CHP generation projects, where price, size and location make sense. The government will work with the OPA to develop options for small, targeted programs. Over the next 20 years, Ontario will see more community-scale CHP projects. The OPA will create a new standard offer program for CHP projects under 20 MW in specific locations.

The OPA will continue to negotiate larger CHP projects on an individual basis. For example, the OPA and St. Marys Paper Corporation recently signed a 10-year contract for the company to generate clean electricity at a new 30 MW biomass-fuelled plant to be built next to St. Marys existing mill in Sault Ste. Marie. The plan is expected to reach commercial operation by early 2014 and will support 550 direct and indirect jobs.

3 conservation



Conservation is Ontario's most environmentally friendly and cost-effective resource. Conservation initiatives save money and reduce greenhouse gas emissions. Reducing consumption reduces bills for consumers and reduces demand on the system, avoiding the need to build new generation. For every dollar that is invested in conservation, two to three dollars of net savings are realized over the life of the investment. Conservation can also create local jobs in energy audits and energy services.

Accomplishments

From 1995 to 2003, there were no provincial conservation programs — it was not a priority. Since 2003, Ontario has had goals for conservation and as a result, this province has become a North American leader. The goal to reduce peak demand by 6,300 MW by 2025 was included in the 2007 Plan. Ontario is on target to meet this goal.

Ontario's A+ 2009 National Energy Efficiency Report Card from the Canadian Energy Efficiency Alliance

The province raised its grade from a "C-" in 2004 to an A+ in 2009 with its strong commitment to energy efficiency and conservation as cornerstones of its energy plan. In addition to the Green Energy and Green Economy Act, 2009, the report lauds Ontario's energy conservation programs, improved energy efficiency in building codes and product standards, as well as other initiatives supporting energy efficiency.

To improve the quality of the province's air and the efficiency of the system, Ontario invested about $1.7 billion in conservation programs from 2006 to 2010. This will save ratepayers $3.8 billion in avoided costs.

Conservation programs also give customers the tools to help them manage costs, and balance demand in peak periods in winter and summer. Conservation programs also create jobs in the clean energy sector.

Ontario has helped to create a culture of conservation since 2003 by:

- Updating Ontario's building code to make energy efficiency a core purpose.
- Delivering the Home Energy Savings Program which has helped over 393,000 homeowners with energy audits and helped nearly 250,000 homeowners with energy savings and retrofits. Despite the federal government's early withdrawal from funding this conservation program in March 2010, Ontario will continue to support the Home Energy Savings Program until March 31, 2011. This program helped save annual greenhouse gas emissions equivalent to taking over 83,000 cars off the road.
- Initiating the OPA's Great Refrigerator Round Up which has removed more than 230,000 old appliances since 2007. It will result in lifetime savings of more than one million megawatt hours over the life of the program.
- Providing $550 million over two years for energy retrofits in schools.
- Launching the Ontario Solar Thermal Heating Initiative for solar water and air heating projects for institutional, commercial or industrial organizations. The program continues until March 31, 2011. Almost 600 projects have been launched or completed to date.
- Moving forward with Smart Meters and Time of Use billing to encourage consumers to shift electricity consumption away from peak periods of demand; Avoided system expenditures help keep costs down for Ontarians.
- Reducing electricity consumption in government buildings through initiatives such as deep lake water cooling — a reliable, efficient and sustainable way to cool buildings while reducing demand on the grid.

Over the past five years, Ontario's conservation programs have generated over 1,700 MW of peak demand savings — the equivalent of over 500,000 homes being taken off the grid. Local Distribution Companies have been partners in helping Ontario achieve its conservation targets.

Conservation efforts are measured by looking at the results of conservation programs. The impacts of the global economic recession are not counted as part of conservation efforts, although they did result in a significant reduction in electricity demand. The recession also affected the level of participation in conservation programs which, although successful, are not expected to allow Ontario to meets its 2010 interim target. Confirmation of this will occur late in 2011, after program results undergo rigorous verification by independent third-parties. Had the global recession not had a significant impact on Ontario's economy, 2010 conservation achievements would have been significantly higher.

The Plan

Working together to reduce electricity use at peak times makes sound economic and environmental sense. Providing consumers with the benefit of up-to-date and accurate electricity consumption readings is also critical to the creation of a culture of conservation. The government is committed to moving forward with implementation of a Time-of-Use pricing structure that balances benefits for both the consumer and the electricity system as a whole.

To help families, Ontario will move the off-peak period for electricity users to 7 p.m. which will provide customers with an additional two hours in the lowest cost period. This change will be in effect for the May 2011 Regulated Price Plan update.

Time-of-Use

"On average, most farmers will pay slightly less on time-of-use billing than they currently pay. Advantages for farmers will be modest with a savings in the range of one to five per cent. However, the advantages for the power supply system will be substantial…"

- Don McCabe, Ontario Federation of Agriculture

Ontario is already a North American leader in conservation (the province conserved over 1,700 MW since 2005). The government's target is 7,100 MW and 28 TWh by 2030. This would mean the equivalent of taking 2.4 million homes off the grid. This level of conservation will reduce Ontario's greenhouse gas emissions by up to 11 megatonnes annually by 2030. These targets are among the most aggressive in North America.

As part of the Green Energy and Green Economy Act, 2009, Local Distribution Companies (LDCs) will become a more recognizable "face of conservation" and have been assigned conservation targets which they must meet as a condition of their licence. LDCs will meet their targets through a combination of province-wide and local conservation programs.

Ontario proposes to provide support for homeowners to have energy audits to become better informed of the opportunities to improve the energy efficiency of their homes.

Conservation targets

Date	2015	2020	2025	2030
Capacity	4,550 MW	5,840 MW	6,700 MW	7,100 MW
Generation	13 TWh	21 TWh	25 TWh	28 TWh

These targets will be met through a combination of programs and initiatives:

- Innovative energy efficiency programs for residential, commercial and industrial sectors
- Next-generation building code updates and standards for appliances and products
- Demand response programs to help reduce peak demand
- Time-Of-Use rates

The government anticipates that the commercial sector will contribute 50 per cent of the conservation target; residential sector will contribute 30 per cent; and industrial sector 20 per cent.

Over the next 20 years, Ontario's conservation targets and initiatives are projected to save about $27 billion in ratepayer costs on the basis of a $12 billion investment. Conservation will also do more than that by helping to ensure that Ontario's air is cleaner and the electricity sector reduces its impact on the environment.

Ontario will continue to provide broad support for achieving these targets through policy initiatives such as bringing forward a proposed regulation to require the broader public sector (municipalities, universities, schools and hospitals) to develop energy conservation plans.

In early 2011, together with LDCs, Ontario will launch a number of new programs, which will allow the province to meet its conservation targets over the next few years and make up for the slower period between 2009 and 2010. The programs will target all sectors, be better coordinated and have greater customer focus than previous programs.

Ontario is designing, implementing and funding a province-wide electricity conservation and demand management program for low-income residential consumers . Ontario is also developing a low-income energy program comprised of natural gas conservation, customer service standards and emergency financial assistance.

These new conservation programs, together with programs for very large industrial customers, will require an investment of about $3 billion over the next five years. The results will be significant: an avoided lifetime supply cost of $10 billion and a net benefit to Ontario ratepayers of about $7 billion over the life of the conservation measures.

4 reliable transmission/ modern distribution

Reliable transmission and modern delivery is the backbone of Ontario's electricity system. It is crucial for supporting Ontario's evolving supply mix, including the closing of coal-fired plants by 2014 and the further expansion of Ontario's clean energy resources. Reliable, safe transmission brings electricity from large generators to Ontario's largest industries and local distribution companies who in turn, deliver to homes and businesses. A modern distribution system, utilizing new technology, allows for greater customer control, incorporates renewable energy, enhances reliability, and supports new technology like electric vehicles.

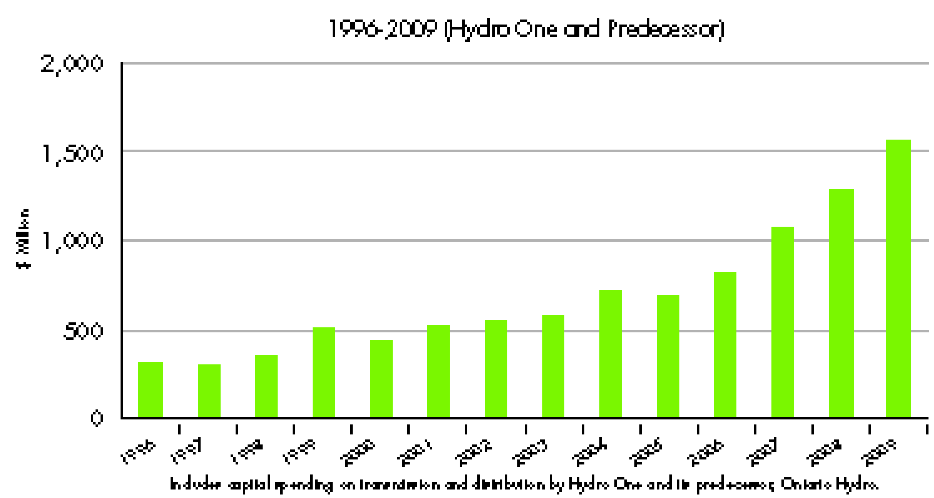
Transmission

Ontario must take the transmission system that's been built over the past century and continue to renew and update it to meet Ontario's growing population, evolving supply mix, and enable more distributed generation.

The Ontario government has taken early and decisive steps to enhance existing electricity infrastructure. It is important to ensure that Ontario can efficiently upgrade the grid to carry additional renewable generation to homes, businesses and industries.

Since 2003, Hydro One has invested more than $7 billion in its transmission and distribution systems. The average annual investment has been double what it was from 1996-2003.

FIGURE 10: GRID INVESTMENTS



Some of Ontario's recent investments include:

- The launch of the Bruce to Milton transmission expansion project — the largest electricity transmission investment in Ontario in the last 20 years, which will connect refurbished nuclear units and additional renewable energy to the grid.
- Ongoing work to reinforce the power transfer capability between northern and southern Ontario including additional 750 MW of planned clean northern generation (Lower Mattagami and some northern FIT Program projects).
- The new Ontario-Québec Interconnection Project (2010), which increased access to 1,250 MW of hydroelectric power and enhanced system reliability in eastern Ontario.
- Additional transmission projects that will facilitate the retirement of coal-fired generation, including transmission reinforcement in the Sarnia area, the installation of new transformers in the northern GTA, and voltage support facilities in the Niagara, London and Kitchener areas. These projects represent an investment of over $400 million.
- Over 15 per cent of transformer stations across Ontario have received overhauls in the past five years, amounting to a total investment of $850 million.
- Installation of almost 4.3 million smart meters across the province, which are already helping with outage management and remote meter reading and reducing the number of estimates for consumers.
- Early investments in Smart Grid infrastructure and technologies, including pilots and demonstration projects. These projects will help Ontario move toward a Smart Grid system that can integrate energy monitors, home automation systems, in-home renewable generation and electric cars.
- Hydro One's $125-million Grid Control Centre opened in 2004 and uses some of the most sophisticated technology in the world to efficiently manage the bulk of Ontario's electricity network.

Reliability has also been improved since 2003 due to a combination of new generation, transmission upgrades, reduced load growth and successful conservation programs. For example, Toronto's reliability was enhanced with the installation of two new underground cables between downtown transfer stations and will be further assisted by reinforcement and upgrade projects worth about $360 million. Annual capital investments by Ontario's Local Distribution Companies, including Hydro One, have averaged $1.1 billion between 2004 and 2009, maintaining reliable and high quality power for Ontario's electricity customers. These investments have made the operation of the system more cost-effective, which will have an impact on Ontarians' bills over the long term.

Modern Distribution

Local distribution systems are an important link in how electricity moves from generators to homes and businesses. In 2003, Ontario's distribution systems often relied on older technology. The government's move towards a Smart Grid was driven by the need to replace aging infrastructure, introduce customer control, incorporate more renewable energy and accommodate new adaptive technology such as electric vehicle charging. Over time, LDCs will have to replace old mechanical infrastructure with newer automated infrastructure that meets Ontario's future needs.

A modern distribution system must be able to accommodate new energy supply from a variety of sources and deliver it reliably to consumers. It must take advantage of Smart Grid technologies to enable efficient and cost-effective delivery of electricity, helping customers to better manage their electricity use, and integrate more renewable energy.

Building a Smart Grid that can coordinate the production of power from large numbers of small power producers and allow utilities to more efficiently manage their grid infrastructure is another essential element of Ontario's clean energy future. Other jurisdictions (Australia, Great Britain and California) are moving toward a smarter grid, but Ontario is leading the way in many areas. By leveraging existing communications technology, a Smart Grid will enable the two-way power flow of electricity across the grid. The Smart Grid will help incorporate distributed generation. It will also improve grid automation with real-time information that will help save energy, reduce the cost of supply over time and increase reliability.

A Smart Grid is a more intelligent grid infrastructure, incorporating communications technology and automation to:

- Maximize existing infrastructure
  - Rather than building out more traditional grid infrastructure (poles, wires, etc), a Smart Grid will use Information Technology solutions to improve and automate distribution.
- Modernize the grid
  - The current distribution system in some places is decades old. A modernized grid is critical for improving reliability, home automation and adapting to evolving transportation needs.
- Lay the foundation for Smart Homes
  - A Smart Grid will put in place the intelligent infrastructure required to support applications for home automation, conservation and smart charging for electric vehicles.

The Green Energy and Green Economy Act, 2009 identified three main areas of focus for Ontario's Smart Grid:

- Helping consumers become active participants in conservation.
- Connecting new and renewable sources of energy to the overall system (consumers and businesses produce energy that can be connected to the local system) to help address power demands.

- Creating a flexible, adaptive grid that can accommodate the use of emerging, innovative energy-saving technologies and control systems.

Smart meters provide a foundation for the Smart Grid and provide customers with timely and accurate information about their electricity use. Smart meters also provide utilities with automatic notification of outages, save on in-person meter-reading costs and enable Time-of-Use pricing.

Smart meters also help avoid system costs that in turn save money for ratepayers: Hydro Ottawa saved $200,000 in meter reading in 2008 and Toronto Hydro estimates that smart meters will cut meter-reading costs by $2.5 million by 2010.

Future Needs

The Ontario government, working with its agencies, will move forward responsibly on a number of new and modernizing transmission projects as well as on improving and maintaining the province's existing infrastructure across all regions in Ontario. These improvements will also balance environmental concerns and the cost to ratepayers. In addition to evaluating the province's need for transmission to integrate renewables, meet provincial demand growth and ensure reliable service, system planning will address community needs. For example, a transmission solution to maintain reliable supply in the southwest GTA will be required.

The Plan

In 2009, the government asked Hydro One to start planning and developing a series of new transmission and distribution projects. Since that time, there have been a number of developments, such as the substantial interest in the Green Energy and Green Economy Act, 2009 to develop renewable energy projects.

Based on the advice of the OPA, the government will prudently move forward with cost-effective priority transmission projects that meet current and future demand and also:

- Accommodate renewable projects;
- Serve new load; and
- Support reliability.

Ontario will proceed first with an investment of approximately $2 billion in five priority projects to be completed in the next seven years, which will ensure a growing mix of renewable sources can be reliably transmitted across the province. These priority projects together with the Bruce to Milton line, in addition to various other station and circuit upgrades, will enable approximately 4,000 MW of additional renewable energy.

FIGURE 11: TRANSMISSION INVESTMENTS: COMPLETE, UNDERWAY AND PROPOSED

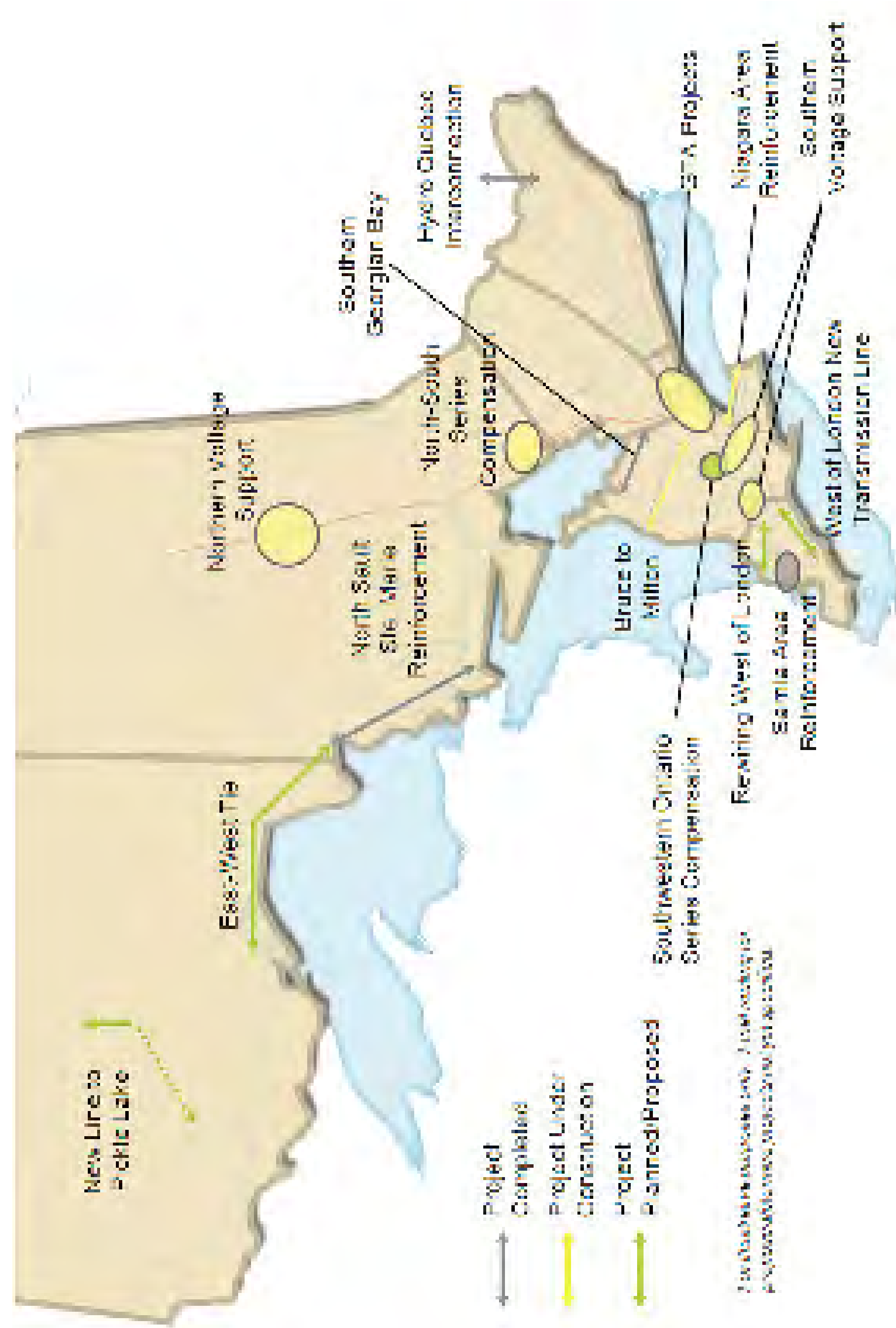


FIGURE 12: PRIORITY TRANSMISSION PROJECTS

Project	Type	Need	Target Completion Date
Series compensation in Southwestern Ontario	Upgrade	Add renewables to grid	2014
Rewiring west of London	Upgrade	Add renewables to grid	2014
West of London	New Line	Add renewables to grid	2017
East-West Tie	New Line	Maintain system reliability, allow more renewables, accommodate electricity requirements of new mineral processing projects.	2016-17
Line to Pickle Lake	New line	Serve industry needs and help future remote community connection	Pending consultation

Given the nature of the transmission upgrades in southwestern Ontario, including series compensation, rewiring and a new line west of London, the government intends to direct Hydro One to carry out these projects immediately.

The East-West tie will be submitted to the OEB to carry out a designation process to select the most qualified and cost-effective transmission company to develop the line.

To ensure successful and timely implementation of the line to Pickle Lake, the government will work with its agencies and the multiple parties involved, including the Federal government, local industries, and First Nation communities that stand to benefit from the project to establish an implementation schedule and a proponent for the line.

Transmission planning will also continue at the regional level, using an approach that considers conservation, demand management, distributed generation and transmission. Regional plans will assess needs based on a region's unique resource mixes and community priorities. Load growth and system reliability are also factors in determining system planning and transmission solutions. Ontario will continue to plan and study additional transmission projects as demand and changes to supply require.

To build a modern system, the government will issue a set of Smart Grid principles and objectives to the Ontario Energy Board. These will provide guidance to LDCs in modernizing their distribution systems and enable the smart home of the future. LDCs will develop smart grid plans and ensure that these are coordinated across the Province. The government will also establish a Smart Grid Fund in 2011 which will provide assistance to Smart Grid companies with a strong Ontario presence. This will lead to new economic development opportunities and bolster Ontario's position as a leader in the Smart Grid.

5 aboriginal communities

Accomplishments

The Ontario government is committed to encouraging opportunities for Aboriginal participation in the energy sector and has launched several initiatives to support participation by First Nation and Métis communities in energy projects, including:

- The Aboriginal Energy Partnerships Program
- The FIT Program: 17 aboriginal-led or partnered projects have secured contract offers
- The $250-million Aboriginal Loan Guarantee Program

Ontario also has a significant partnership at the $2.6 billion Lower Mattagami hydroelectric project, which will see Moose Cree First Nation have up to a 25 per cent equity position with OPG.

Future Needs

First Nation and Métis communities have diverse energy needs and interests. Ontario will work to ensure there is a wide range of options for Aboriginal participation in Ontario's energy future.

Conservation

Conservation priorities and the applicability of programs will vary between First Nation and Métis communities. Community education and youth engagement are also critical for conservation success. Ontario will launch programs to support participation in conservation initiatives, including Aboriginal Community Energy Plans and targeted conservation programs.

Renewable Energy

Future opportunities for First Nation and Métis communities include:

- Partnerships with private developers on confirmed FIT projects under development,
- Development of smaller renewable microFIT projects, like small wind or solar, to build community capacity in energy and generate income.

Existing Green Energy and Green Economy Act, 2009 support programs will be adjusted to ensure that aboriginal communities can take advantage of these opportunities. Aboriginal participation levels will also be reviewed during the regular FIT program review to determine whether adjustments are needed to the rules and incentives.

Transmission

Where new transmission lines are proposed, Ontario is committed to meeting its duty to consult First Nation and Métis communities in respect of their aboriginal and treaty rights and accommodate where those rights have the potential to be adversely impacted. Ontario also recognizes that Aboriginal communities have an interest in economic benefits from future transmission projects crossing through their traditional territories and that the nature of this interest may vary between communities.

There are a number of ways in which First Nation and Métis communities could participate in transmission projects. Where a new transmission line crosses the traditional territories of aboriginal communities, Ontario will expect opportunities be explored to:

- Provide job training and skills upgrading to encourage employment on the transmission project development and construction.
- Further Aboriginal employment on the project.
- Enable Aboriginal participation in the procurement of supplies and contractor services.

Ontario will encourage transmission companies to enter into partnerships with aboriginal communities, where commercially feasible and where those communities have expressed interest. The government will also work with the OPA to adjust the Aboriginal Energy Partnerships Program — currently focussed on renewable energy projects — to provide capacity funding for aboriginal communities that are discussing partnerships on future transmission projects.

The Plan

Ontario recognizes that successful participation by First Nation and Métis communities will be important to advance many key energy projects identified under a Long-Term Energy Plan. The path forward needs to be informed by regular dialogue with First Nation and Métis leadership through distinct processes. Working with First Nation and Métis leadership, Ontario will look for opportunities to promote on-going discussion of these issues.

Ontario's remote First Nation communities currently rely on diesel generation for their electricity supply — but diesel fuel is expensive, difficult to transport, and poses environmental and health risks. According to analysis done so far, transmission connection would be less expensive over the long term than continued diesel use for many remote communities.

New transmission supply to Pickle Lake is a crucial first step to enable the connection of remote communities in northwestern Ontario. A new transmission line to Pickle Lake — one of this plan's five priority projects — will help to service the new mining load and help to enable future connections north of Pickle Lake. Subject to cost contributions from benefiting parties, Ontario will focus on supplying Pickle Lake from the Ignace/ Dryden area immediately. A line to serve the Nipigon area specifically will continue to be considered as the need for it evolves.

As part of this project, the government will also ask the OPA to develop a plan for remote community connections beyond Pickle Lake, including consideration of the relevant cost contributions from benefiting parties, including the federal government. This plan may also consider the possibility of onsite generation such as small wind and water to reduce communities' diesel use.

6 energy in Ontario's economy — capital investments

Energy has a significant impact on Ontario's economy. Ontario businesses rely on electricity to produce goods and services and it is essential to our quality of life.

- Ontario's electricity sector is a $15 billion annual industry.
- Energy accounts for eight per cent of Canada's GDP.
- Some 95,000 Ontarians are currently directly and indirectly employed in the energy sector.
- More than $10 billion has been invested in Ontario in new clean energy projects that are online or under construction.
- Ontario has attracted more than $16 billion in private sector investments in the energy sector in the past year.

Ontario's progress in modernizing and upgrading electricity has not only benefited electricity users, it has strengthened the economy by attracting investment and creating jobs. Large infrastructure projects typically have high GDP and employment impacts, and this is also true of the ongoing and planned investments in Ontario's electricity sector.

Hydroelectric investment

Waterpower has been helping to fuel Ontario's economic growth for more than 100 years and is the backbone of renewable supply.

Ontario hydroelectric producers spend $250 million annually in operating and maintenance costs and in the past decade alone have made additional capital investments of $400 million to bring new waterpower online. Today, Ontario's hydroelectric producers directly employ more than 1,600 people and support an additional 2,000 jobs.

Hydroelectric has an even greater impact in Ontario's north, where it accounts for more than 80 per cent of the electricity generated. Twenty-four of 65 generating stations run by OPG are located in Ontario's north, representing close to 2,000 MW.

Many older hydroelectric facilities date to Ontario's early industrial mining and forestry activities and some of these sites are being rebuilt at higher capacity. Recent substantial investments are playing an important economic role in the north. The Lower Mattagami River Hydroelectric Project, Ontario's largest hydroelectric project in 40 years, will bring a $2.6-billion investment into northeastern Ontario and create up to 800 construction jobs.

In southwestern Ontario, work is underway on the Niagara Tunnel project, the single biggest construction project for the Niagara region since the Beck 2 Generating Station was built 55 years ago. The project means that region will benefit from over 230 construction jobs.

Wind, Solar and Bio-Energy investment

Ontario is creating a new sector for investment and is becoming a global destination of choice for clean energy developers and suppliers. Ontario's Green Energy and Green Economy Act, 2009 has laid the foundation for economic opportunities throughout the province. In the coming years, over 20,000 people will be employed in renewable energy and development activities including manufacturing triggered by North America's most comprehensive FIT program.

Ontario has already attracted more than $16 billion of private sector investment and over 20 companies have announced plans to set up or expand operations in Ontario. This activity will create or support indirect jobs in areas such as finance, consulting and other manufacturing, service, and development industries.

Many communities that were hard-hit during the recent economic downturn are reaping benefits of Ontario's growing clean energy economy. According to the Windsor Essex Economic Development Commission, of the 6,000 new jobs created in Windsor in the past 10 months, five to 10 per cent are tied to renewable energy.

The Green Energy and Green Economy Act, 2009 has already attracted the single-largest investment in renewable energy in provincial history. The Consortium, led by Samsung C&T Corporation, is investing $7 billion to create 2,500 MW of new wind and solar power in Ontario. The investment will lead to more than 16,000 new clean energy jobs to build, install and operate the renewable generation projects and associated manufacturing. The consortium is also working with major partners to secure four manufacturing plants in the province. This will lead to the creation of 1,440 manufacturing and related jobs to build wind and solar technology for use in Ontario and export across North America.

Plans for the first of the four plants have already been announced. Samsung and Siemens have said they intend to build Ontario's first wind turbine blade manufacturing plant, creating up to 900 direct and indirect jobs. The supply-chain of Ontario's new clean energy economy is providing benefits to other sectors of the economy. For example, the Consortium intends to use Ontario steel in its projects, subject to necessary quality standards.

The clean energy sector is also providing new opportunities to people in rural Ontario. Farmers are leasing portions of their land for wind turbines, allowing them to generate income while continuing to farm. For example, in Port Alma, local farmers and landowners are leasing their land to the 44-turbine Kruger Energy wind power project, which produces enough clean electricity to power 30,000 households.

Province-wide, farmers and agri-food businesses received a total of $11.2 million to develop and build generating systems that produce clean energy, reduce electricity costs and contribute to local economies through OMAFRA's Biogas Systems Financial Assistance Program, which ran from September 2008 to March 2010.

> "Building a clean energy economy is not an issue that splits left from right. It's about past and future. People of all political stripes who are entrusted in building a modern economy can – and do – look ahead."
>
> - Rick Smith, founding partner of Blue Green Canada

Modernization of nuclear fleet

The nuclear sector has contributed a great deal to Ontario's economy over the past forty years. According to the Canadian Nuclear Association, the sector supports over 70,000 jobs across Canada and injects some $6 billion into the national economy every year. The Organization of CANDU Industries estimates that its 165 members employ over 30,000 people, many of them here in Ontario. Its members supply goods and services for nuclear reactors in domestic and export markets.

Plans to upgrade and refurbish Ontario's nuclear plants are expected to create and support thousands of jobs and inject billions of dollars into this sector over the next decade. A report by the Canadian Manufactures and Exporters estimates that the refurbishment and operation of the Bruce and Darlington units will create or sustain 25,000 jobs and provide $5 billion in annual economic activity.

The design and construction of two new nuclear units at Darlington will employ up to 3,500 people and support many thousands more indirect jobs. Ongoing operation at the plant will require a further 1,400 tradespeople, nuclear operators, and engineering and technical support staff for the duration of the plant's life.

Transmission upgrades

Thousands of Ontarians are employed in the province's electricity transmission sector and billions of dollars in planned upgrades to and expansion of the system are expected to support and create thousands more jobs in the future.

Fully owned by the Province of Ontario, Hydro One is the province's largest electricity transmission and distribution company. It owns 97 per cent of the transmission facilities in the province and employs approximately 5,400 workers, many of them highly skilled technicians, in communities throughout Ontario.

This Plan includes a commitment to develop five priority transmission projects. Employment on the five priority projects alone will peak at over 5,000 in 2013. This new transmission capacity will enable further generation development, including many new private-sector renewable projects.

The rollout of new transmission projects will also allow communities, including Aboriginal communities, to develop more small-scale renewable generation and, in certain cases, reduce their dependence on polluting forms of electricity generation.

Coal plant conversion

Converting Ontario's existing coal-fired generating stations to new fuels will create new constructions jobs and support clean energy jobs in operations and maintenance.

For example, the Atikokan biomass conversion project will create up to 200 construction jobs and help protect jobs at the plant. It will also support an estimated 20 to 25 jobs in Ontario related to the production of wood pellets and sustain other jobs in the forestry sector. The project will provide engineering and construction jobs during the conversion as well as ongoing employment in the forestry and transportation sectors to keep the station supplied with fuel. Natural gas conversion at Thunder Bay will provide additional jobs in pipeline construction and ongoing operations.

Conservation

Conservation programs contribute to local and regional jobs, creating employment and new business opportunities in a number of areas, including technology and product development, manufacturing, distribution, marketing, sales, installation and maintenance. For example, Ontario's $3-billion investment in conservation programs over the next five years is expected to create or sustain about 5,000 jobs annually.

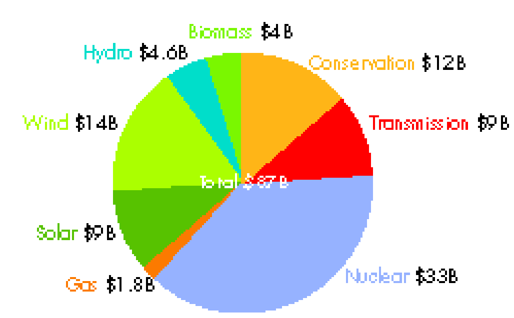
Capital Investments

Ontario's electricity sector is a $15-billion annual industry. Investments in the electricity system are helping to clean Ontario's air, improve the reliability of the energy supply and create jobs and economic opportunities in communities across the province. Since 2003, over $10 billion has been invested to bring new supply on line, and over $7 billion has been spent to strengthen the transmission system. Ontario has also attracted more than $16 billion in private sector investment through the FIT program.

Investments over the past seven years to build new cleaner generation and modernize electricity infrastructure has increased significantly to make up for years of underinvestment. Needed capital investments in Ontario's energy system over the next 20 years will be significant, and are in line with the government's efforts to upgrade and replace aging infrastructure. For example, the ReNew Ontario Infrastructure plan invested $30 billion over four years in capital projects across the province.

This Plan outlines essential capital expenditures to continue building a clean and modern electricity system and to keep the lights on for Ontario families and businesses. The total capital cost in 2010 dollars is estimated to be $87 billion over the life of the Plan. This accounts for new and refurbished energy supply, transmission and distribution infrastructure and conservation investments. This Plan provides more investments over the 2007 Plan due to increased investments in renewables, updated capital cost assumptions, and more certainty on the costs of nuclear refurbishments and new build. These cost estimates will be further refined by the OPA in the coming months and then submitted to the OEB.

FIGURE 13: ESTIMATED CAPITAL COST OF LONG-TERM ENERGY PLAN: 2010 TO 2030 ($ BILLIONS)



The capital investments outlined are through both the private and public sector, and the majority will be paid for by electricity consumers spread over many years, depending on the cost recovery mechanism. (For example, electricity generators typically recover their investment over 20 years, whereas transmission investments may take up to 40 years to be fully repaid). This ensures that the annual costs to consumers, as reflected on electricity bills are spread over a longer period of time.

Conservation expenditures in this Plan include direct program costs and additional capital expenditures driven by higher appliance energy efficiency standards and higher building code efficiency standards.

Overall, renewables account for one third of total expenditures, nuclear just over one third, and natural gas, conservation and transmission the remainder. The breakdown is reflective of the Plan's objective to deliver a balanced and diverse supply mix that is cost effective, clean and helps create clean energy jobs.

7 electricity prices

Over the past 20 years, the price of water, fuel oil and cable TV have outpaced the price of electricity. Over the next 20 years, Ontario can expect stable prices that also reflect the true cost of electricity. The government will need to take a balanced and prudent approach to investment and pricing that ensures that Ontario's children and grandchildren have a clean, reliable system.

Ontarians now pay the true cost of electricity to ensure that essential investments are made in clean energy and modern transmission. About 40 per cent of Ontario's electricity generation is subject to price regulation, contributing significantly to predictable prices for Ontario consumers. Regulated Price Plan (RPP) rates (adjusted every six months) ensure pricing reflects the true cost of generating electricity. This helps to provide stable and predictable electricity prices for consumers.

Accomplishments

In 2003, the electricity system was in significant decline but Ontario families and businesses have invested in the creation of cleaner sources and the restoration of reliability. The cost of energy has increased in order to provide cleaner, more reliable energy for generations to come.

The government has also taken several steps to keep the cost of electricity down for Ontario families and businesses. Actions taken to prudently manage expenditures total over $1 billion, including:

- Freezing the compensation structures of all non-bargained public sector employees for two years – which include the five energy agencies.
- Limiting travel costs and other expenses for public sector workers.
- Requesting that Hydro One and Ontario Power Generation revise down their 2010 rate applications to find savings and efficiencies.
- The IESO has reduced costs by $23 million over the past seven years.
- For 2011, the OPA has reduced its overall operating budget by 4.1 per cent.
- Hydro One will reduce operations costs by $170 million in 2010 and 2011. Information technology upgrades will save $235 million over the next four years.
- OPG is reducing operations costs by more than $600M over the next four years.

Ontario has taken steps to lower the hydro debt left by the previous government. In 1999, the restructuring of Ontario Hydro and the attempt to sell-off Hydro left electricity consumers with a debt of $20.9 billion. Since 2003, Ontario has decreased that stranded debt by $5.7 billion. Payments toward the debt are made through Payments in Lieu of Taxes, dedicated income from government energy enterprises, and by ratepayers through the Debt Retirement Charge.

The government has also launched a number of initiatives to help Ontario families and businesses manage electricity bill increases. Some of these include:

- The Northern Ontario Energy Credit, a new, permanent annual credit to help families and individuals in the North who face high energy costs. The yearly credit of up to $130 for a single person and up to $200 for a family would be available to over half of all northern Ontario households.
- Ontario Energy and Property Tax Credit, starting with the 2010 tax year, to low-income Ontarians who own or rent a home would receive up to $900 in tax relief, with seniors able to claim up to $1,025 in tax relief to help with both their energy costs and property tax. Overall, the proposed Ontario Energy and Property Tax Credit would provide a total of about $1.3 billion annually to 2.8 million Ontarians.

Energy Consumer Protection Act, 2010:

On January 1, 2011, new rules will take effect under the Energy Consumer Protection Act, 2010 that will help protect electricity and natural gas consumers by putting an end to unfair practices by energy retailers. The rules will ensure that consumers receive accurate price disclosure from all energy retailers before they sign contracts, helping to protect Ontario families and seniors.

Ontario is helping low-income Ontarians with their energy costs through a province-wide strategy to help consumers better manage their energy consumption and costs, including:

- Establishing a new emergency energy financial assistance fund.
- Implementing enhanced customer service rules that will assist all customers, particularly low-income Ontarians.

Ontario is also developing a comprehensive electricity conservation program for low-income households in coordination with the natural gas utilities. Through the conservation measures, customers will be better able to manage their energy bills.

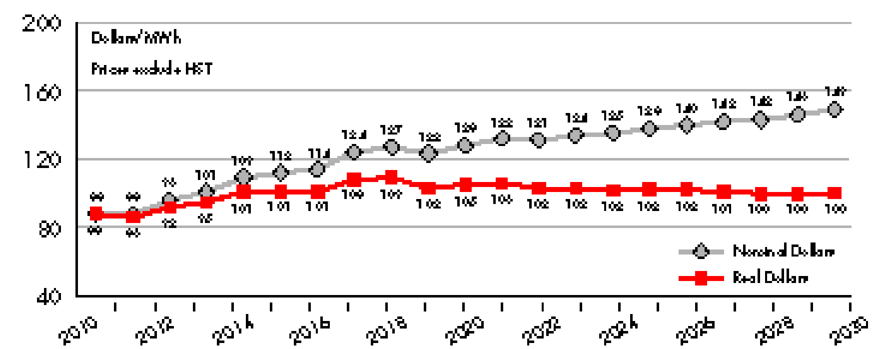
The Plan

Industrial Users

Due to investments to make the electricity system cleaner and more reliable for industry, the government projects that the industrial rate will increase by about 2.7 per cent annually over the next 20 years. The Ontario government has introduced initiatives to enhance the efficiency and competitiveness of large industrial consumers as well as protect jobs and local economies. These include:

- The Industrial Conservation Initiative will help the province's largest industrial and manufacturers to conserve energy, save on costs and increase their competitiveness. By changing the Global Adjustment Mechanism, large industrial users can shift their usage off peak times and save on electricity costs.
- The OPA's Industrial Accelerator Program has been launched to assist transmission-connected industrial electricity users to fast-track capital investment in major energy-efficiency projects.
- The Northern Industrial Energy Rate Program provides electricity price rebates for qualifying northern industrial consumers who commit to an energy efficiency and sustainability plan. On average, the program reduces prices by about 25 per cent for large facilities.

FIGURE 14: INDUSTRIAL PRICE PROJECTIONS (2010-2030)



Helping Ontario Small Businesses and Families

In order to ensure that Ontario has a clean, modern system that increases renewables, ensures reliability and creates jobs, continued investments in the electricity system are essential.

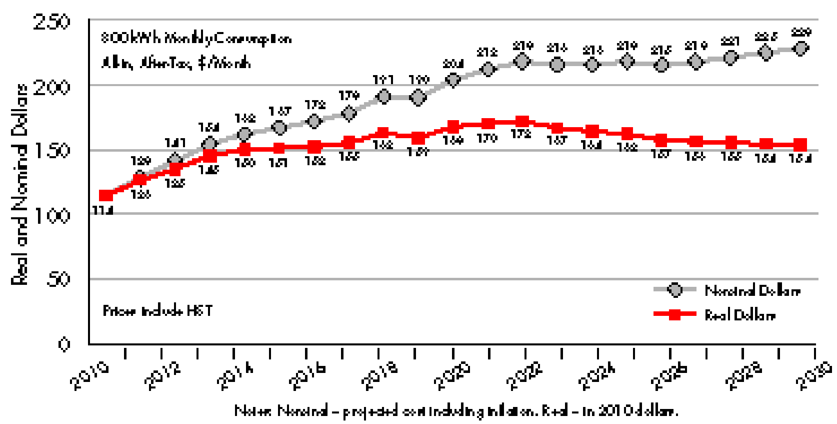
Based on the significant investments in clean, modern energy outlined in this plan, the government projects, based on current forecasts, that electricity prices will increase. Over the next 20 years, prices for Ontario families and small businesses will be relatively predictable. The consumer rate will increase by about 3.5 per cent annually over the length of the long-term plan.

Over the next five years, however, residential electricity prices are expected to rise by about 7.9 per cent annually (or 46 per cent over five years). This increase will help pay for critical improvements to the electricity capacity in nuclear and gas, transmission and distribution (accounting for about 44 per cent of the price increase) and investment in new, clean renewable energy generation (56 per cent of the increase).

Continued investments in transmission, conservation and supply are needed for a system that provides more efficient and reliable electricity to consumers whenever they need it and does not pollute Ontario's air or negatively affect the health of citizens and future generations.

After five years, Ontario will have largely completed the transition to a cleaner more reliable system due to the replacement of coal-fired generation and new renewable generation under the GEA. Once these investments have been made, price increases are expected to level off. The investments that the entire province is making in the future of electricity will help to ensure that Ontario never finds itself in the dire straits it was in just seven years ago.

FIGURE 15: RESIDENTIAL PRICE PROJECTIONS (2010-2030)



However, in the next five years, the government recognizes that the increases will have an impact on Ontario families and businesses.

The government's 2010 Ontario Economic Outlook and Fiscal Review took action to help Ontarians who are feeling the pinch of rising costs and electricity prices. The Ontario government proposed direct relief through a new Ontario Clean Energy Benefit (OCEB).

For eligible consumers, the proposed OCEB would provide a benefit equal to 10 per cent of the total cost of electricity on their bills including tax, effective January 1, 2011. Due to the length of time required to amend bills, the price adjustments would appear on electricity bills no later than May 2011, and would be retroactive to January 1, 2011.

Every little bit of assistance helps during lean times. The proposed OCEB together with the Northern Ontario Energy Credit and the Ontario Energy and Property Tax Credit will all help mitigate electricity costs for families.

Eligible consumers would include residential, farm, small business and other small users. The proposed OCEB would help over four million residential consumers and over 400,000 small businesses, farms and other consumers with the transition to an even more reliable and cleaner system.

Benefits for Eligible Consumers

Customer Monthly Consumption	Current Estimated Monthly Bill	Estimated Bill after Ontario Clean Energy Benefit	Monthly Benefit* (10%)	Yearly Benefit (10 %)
Typical Residential 800kWh	$128	$115.20	$12.80	$153.60
Small Business 10,000kWh	$1,430	$1,287	$143	$1,716
Farm 12,000kWh	$1,710	$1,539	$171	$2,052
*Typical 2011 monthly benefit for a consumer. Benefit amount will vary based on actual price, consumption and location				

Providing the 10 per cent OCEB to Ontarians is a responsible way of helping Ontario families and businesses through the transition to a cleaner electricity system. The OCEB would help residential and small business consumers over the next five years as the grid is modernized. The government has introduced legislation to implement the proposed OCEB.

Working together to reduce electricity use at peak times makes sound economic and environmental sense. Providing consumers with the benefit of up-to-date and accurate electricity consumption readings is also critical to the creation of a culture of conservation. The government is committed to moving forward with implementation of a Time-of-Use pricing structure that balances benefits for both the consumer and the electricity system as a whole.

To help families, Ontario will move the off-peak period for electricity users to 7 p.m. which will provide customers with an additional two hours in the lowest cost period. This change will be in effect for the May 2011 Regulated Price Plan update.

This plan has outlined a new clean, modern and reliable electricity system for the people of Ontario. Instead of a system that was polluting, unreliable and in decline with unstable pricing, Ontarians will have a North American-leading clean energy system that keeps the lights on for generations to come, creates jobs for Ontario families and ensures that the air they breathe is cleaner.

FIGURE 16: SAMPLE BILL

Your Electricity Bill

Service Address: Customer name
Address
City, Ontario

Monthly Statement

Account Number 000 000 000 000 0000 0 **Statement Date** June 30, 2011

Meter Number 0000000

Electricity Used This Billing Period

Metered usage in kilowatt-hours = 800 kWh

Your Electricity Charges	
Electricity	
On-Peak: 153.60 kWh @ 9.900¢	$15.21
Mid-Peak: 216.40 kWh @ 8.100¢	$17.69
Off-Peak: 428.00 kWh @ 5.100¢	$21.83
Delivery	$46.90
Regulatory	$6.04
Debt Retirement Charge	$5.60
Your Total Electricity Charges	$113.27
HST Federal $5.67 Provincial $9.06	$14.73
Subtotal	$128.00
Adjustments	
Ontario Clean Energy Benefit (-10%)	-$12.80 CR
Total Amount	**$115.20**

Sample bill for illustrative purposes only. Other adjustments may apply.

Appendix One: who does what

Ontario Power Generation: Generates 60 per cent of Ontario's electricity.

Hydro One: Operates 97 per cent of Ontario's transmission network.

Independent Electricity System Operator: Ensures reliability, forecasts short-term demand and supply, monitors supply, and manages the Ontario wholesale market.

Ontario Power Authority: Responsible for system planning (generation, transmission, demand and conservation), contracts for new generation and conservation, and manages contracts for about 40 per cent of Ontario's generation.

Ontario Energy Board: Independent, quasi-judicial regulator of Ontario's energy sector

Licensed Transmission System Operators: Transmit electricity (There are five; Hydro One Networks is the largest).

Local Distribution Companies: More than 80, mostly owned by municipalities, deliver electricity and serve customers in a given area.

Electricity Retailers: Seventy-seven private-sector companies that sell contracts to businesses and consumers

Privately-owned generators: Facilities that produce energy (Bruce Power, wind and solar energy companies)

Appendix Two:

consultations and next steps

Ontario's Long-Term Energy Plan was informed by public and stakeholder consultations as well as advice from the OPA. In addition to issuing this plan, the government is posting a proposed supply mix Directive on the Environmental Registry for a 45 day public comment period. Following this posting, the directive will be finalized and sent to the OPA. The OPA will consult publicly during the development the Integrated Power System Plan (IPSP) and submit the plan to the OEB. The OEB will conduct a review of the IPSP including public hearings. The final IPSP will constitute the detailed long-term energy plan for the next 20 years. It will be updated every three years as required by regulation.

Public and Stakeholder and Online Consultations
September 21st – November 18, 2010
More than 40 stakeholder sessions and over 2,500 online response

↓

Ontario's Long-Term Energy Plan
November 23, 2010

↓

45-Day Posting on Environmental Registry of Proposed Supply Mix Directive
www.ebr.gov.on.ca
November 23, 2010-January 7, 2011

↓

OPA prepares detailed IPSP, holds consultations and submits it to the OEB
Mid-2011

↓

OEB Review
2011-2012

Appendix Three:

installed capacity (MW)

Installed Capacity	2003	2010 (Projected)	2030 (Projected)
Nuclear	10,061	11,446	12,000
Renewables – Hydroelectric	7,880	8,127	9,000
Renewables – Wind, Solar, Bioenergy	155	1,657	10,700
Gas	4,364	9,424	9,200
Coal	7,546	4,484	0
Conservation	0	1,837	7,100
Total	30,006	36,975	48,000

glossary – of energy terms

Baseload Power: Generation sources designed to operate more or less continuously through the day and night and across the seasons of the year. Nuclear and generally large hydro generating stations are examples of generators that operate as baseload generation.

Biomass: Energy resources derived from organic matter, including wood, agricultural waste and other living cell material that can be burned to produce heat energy or electricity.

Demand Response (DR): Programs designed to reduce the amount of electricity drawn by customers from the grid, in response to changes in the price of electricity during the day, incentive payments and/or other mechanisms. In Ontario, both the OPA and the IESO run demand response programs.

Dispatchable Generation: Sources of electricity such as natural gas that can be dispatched at the request of power grid operators; that is, output can be increased or decreased as demand or availability of other supply sources changes.

Distribution: A distribution system carries electricity from the transmission system and delivers it to consumers. Typically, the network would include medium-voltage power lines, substations and pole-mounted transformers, low-voltage distribution wiring and electricity meters

Feed-in Tariff (FIT): A guaranteed rate program that provides stable prices through long-term contracts for energy generated using renewable resources

Greenhouse Gas (GHG): Gases that contribute to the capture of heat in the Earth's atmosphere. Carbon dioxide is the most prominent GHG, in addition to natural sources it is released into the Earth's atmosphere as a result of the burning of fossil fuels such as coal, oil or natural gas. Widely acknowledged as contributing to climate change.

Intermittent Power Generation: Sources of electricity that produce power only during certain times such as wind and solar generators whose output depends on wind speed and solar intensity.

Kilowatt (kW): A standard quantity of power in a residential-size electricity system, equal to 1,000 watts (W). Ten 100-watt light bulbs operated together consume one kW of power.

Kilowatt-hour (kWh): A standard unit of electrical energy in a residential-size system. One kWh (1,000 watt-hours) is the amount of electrical energy produced or consumed by a one-kilowatt unit during one hour. Ten 100-watt light bulbs, operated together for one hour, consume one kWh of energy.

Load or Demand Management: Measures undertaken to control the level of energy usage at a given time, by increasing or decreasing consumption or shifting consumption to some other time period.

Local Distribution Company (LDC): An entity that owns a distribution system for the local delivery of energy (gas or electricity) to consumers.

Megawatt (MW): A unit of power equal to 1,000 kilowatts (kW) or one million watts (W).

Megawatt-hour (MWh): A measure of the energy produced by a generating station over time: a one MW generator, operating for 24 hours, generates 24 MWh of energy (as does a 24 MW generator, operating for one hour).

MicroFIT: Ontario residents are able to develop a very small or "micro" renewable electricity generation project (10 kilowatts or less in size) on their properties. Under the microFIT Program, they are paid a guaranteed price for all the electricity they produce for at least 20 years.

Peaking Capacity: Generating capacity typically used only to meet the peak demand (highest demand) for electricity during the day; typically provided by hydro, coal or natural gas generators.

Peak Demand: Peak demand, peak load or on-peak are terms describing a period in which electricity is expected to be provided for a sustained period at a significantly higher than average supply level.

Photovoltaic: A technology for converting solar energy into electrical energy (typically by way of photovoltaic cells or panels comprising a number of cells).

Regulated Price Plan (RPP): Rates (adjusted every six months) to ensure electricity pricing reflect the true cost of generating electricity. They provide stable and predictable electricity prices for consumers.

Smart Grid: A Smart Grid delivers electricity from suppliers to consumers using digital technology with two-way communications to control appliances at consumers' homes to save energy, reduce costs and increase reliability and transparency.

Supply Mix: The different types of fuel that are used to produce electricity in a particular jurisdiction. Normally the mix is expressed in terms of the proportion of each type within the overall amount of energy produced.

Terawatt-hour (TWh): A unit of power equal to a billion kilowatt-hours. Ontario's annual electricity consumption is around 140 TWh.

Transmission: The movement or transfer of electricity over an interconnected group of lines and associated equipment between points of supply and points at which it is transformed for delivery to consumers, or is delivered to other, separate electric transmission systems. Transmission of electricity is done at high voltages (50kV or higher in Ontario); the energy is transformed to lower voltages for distribution over local distribution systems.

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Ontario

Electricity Generation Licence

EG-2008-0130

Trout Creek Wind Power Inc.

Valid Until

July 22, 2028

Original signed by

____

Jennifer Lea
Counsel, Special Projects
Ontario Energy Board
Date of Issuance: July 23, 2008

Ontario Energy Board	Commission de l'énergie de l'Ontario
P.O. Box 2319	C.P. 2319
2300 Yonge Street	2300, rue Yonge
27th Floor	27e étage
Toronto, ON M4P 1E4	Toronto ON M4P 1E4

Table of Contents **Page No.**

1 Definitions

In this Licence:

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

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

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

"**Licensee**" means Trout Creek Wind Power Inc.;

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

2 Interpretation

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

3 Authorization

3.1 The Licensee is authorized, under Part V of the Act and subject to the terms and conditions set out in this licence, to generate electricity or provide ancillary services for sale under a contract entered into as part of a Standard Offer Program offered by the Ontario Power Authority. This Licence authorizes the Licensee only in respect of those facilities set out in Schedule 1.

4 Obligation to Comply with Legislation, Regulations and Market Rules

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

4.2 The Licensee shall comply with all applicable Market Rules.

5 Obligation to Maintain System Integrity

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

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

6 Restrictions on Certain Business Activities

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

7 Provision of Information to the Board

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

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

8 Term of Licence

8.1 This Licence shall take effect on July 23, 2008 and expire on July 22, 2028. The term of this Licence may be extended by the Board.

9 Fees and Assessments

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

10 Communication

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

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

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

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

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

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

11 Copies of the Licence

11.1 The Licensee shall:

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

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

SCHEDULE 1 LIST OF LICENSED GENERATION FACILITIES

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

1. The Trout Creek Wind Farm, owned by the Licensee at Lots 23, 24 and 25, Concession 1, Township of South Himsworth, Municipality of Powassen; and Lots 15, 16, 17, 18 and 19, Concession 14, Township of Laurier, District of Parry Sound., Ontario.

ONTARIO ENERGY BOARD

FILE NO.: **EB-2011-0067**

VOLUME: **2**

DATE: **May 5, 2011**

BEFORE:	**Paul Sommerville**	**Presiding Member**
	Marika Hare	**Member**
	Paula Conboy	**Member**

EB-2011-0067

THE ONTARIO ENERGY BOARD

IN THE MATTER OF the Ontario Energy Board Act, 1998, S.O. 1998, c. 15, (Schedule B);

AND IN THE MATTER OF an application by the Ontario Waterpower Association pursuant to section 74(1)(b) of the *Ontario Energy Board Act, 1998* to amend Hydro One Networks Inc.'s Electricity Distribution Licence ED-2003-0043 to exempt Hydro One from sections 6.2.4.1(e)(i) and 6.2.18(a) of the Distribution System Code in respect to waterpower generation facilities.

Hearing held at 2300 Yonge Street,
25th Floor, Toronto, Ontario,
on Thursday, May 5th, 2011,
commencing at 9:45 a.m.

VOLUME 2

BEFORE:

PAUL SOMMERVILLE	Presiding Member
MARIKA HARE	Member
PAULA CONBOY	Member

A P P E A R A N C E S

MAUREEN HELT	Board Counsel
GONA JAFF VINCE COONEY ASHLEY HALE	Board Staff
SCOTT A. STOLL	Ontario Waterpower Association
MICHAEL ENGELBERG	Hydro One Networks Inc.

ALSO PRESENT:

PHILIP LAWEE	Hydromega
PAUL NORRIS	Ontario Waterpower Association
BILL TOUZEL	WESA
ARNOLD CHAN	Xeneca Power
RICK ROBERTS	Lizard Creek Power
KEVIN MANCHERJEE	Hydro One Networks Inc.

I N D E X   O F   P R O C E E D I N G S

E X H I B I T S

U N D E R T A K I N G S

Description	Page No.

NO UNDERTAKINGS WERE FILED IN THIS PROCEEDING

Thursday, May 5, 2011

--- On commencing at 9:45 a.m.

MR. SOMMERVILLE: Thank you. Please be seated. Having gotten out, we want to get back in.

This is the second day of EB-2011-0067. Today is set aside for oral submissions from the parties.

Are there any preliminary matters?

PRELIMINARY MATTERS:

MR. STOLL: Yes, Mr. Chair, there are a couple of things. I provided copies of four of the five undertakings that were given yesterday to Board counsel, and the fifth one will be ready later today for filing. And the one that has not been filed is the appendix A. I am just waiting for some information on the one project before that gets filed later today.

MS. HELT: And that is undertaking J1.2.

MR. STOLL: Correct. So I don't know if you want to spend any time going through that or if it is necessary, but...

MR. SOMMERVILLE: If submissions were to be completed before that undertaking is provided, does anyone consider it to be of such materiality that we ought not to consider submissions without it?

MS. HELT: Just one moment, Mr. Chair. No, Mr. Chair, we do not see a problem with that.

MR. SOMMERVILLE: Thank you.

MR. STOLL: I appreciate that.

Does the Panel have any concern or want to walk through any of the undertaking responses, or are we just going to go right to submissions?

MR. SOMMERVILLE: Unless there are some issues raised by Staff...

MS. HELT: Staff has no concerns.

MR. SOMMERVILLE: Do we have copies of the undertakings for the Panel, please?

[Ms. Jaff and Mr. Cooney pass out documents]

MR. SOMMERVILLE: What I also note is that the schedule, which was formerly K1.4, has changed in at least this particular. Where the definition is for generation facilities for which the primary energy source is water --

MR. STOLL: Right.

MR. SOMMERVILLE: -- and for which the electrical connection is to the distribution system owned by Hydro One Networks Inc., Hydro One shall be exempted.

MR. STOLL: Correct. We were going to get to that after we dealt with the undertakings.

MR. SOMMERVILLE: Thank you.

MR. STOLL: Okay. Since you brought it up, we can go there first. We did -- we took your advice, went back and had a discussion with Hydro One about how we could scope this or make it a little more clear about who this applied to. We tried some different variations, and that was as precise a definition we could get that would cover the types of projects, and we don't know that it leads to creep into other areas.

So I can deal with that more in submissions.

MR. SOMMERVILLE: Perhaps it would be fair just to mention, the location of the project on Crown land, is that a definer that would be useful?

MR. STOLL: Not entirely. That would only take out part of the MNR upfront process, but the class EA two-year process would still be there, and we would still end up with the same permitting process. And federal lands are not treated as Crown lands. They're federal enclaves, and they're subject to a similar process.

MR. SOMMERVILLE: Let me just indicate that this is in the nature of evidence, Mr. Norris, and you should consider yourself to be still under oath.

MR. NORRIS: I appreciate that. Thank you. So it is a good question.

We focussed yesterday on the process on provincial Crown land. We could have taken you through the process on federal Crown land under the Dominion Water Power Act. It is a very similar process. It is very similar in terms of the steps by steps by steps. We focussed on where the majority of the projects were.

I would also observe that all of the other permitting and approvals requirements, Lakes and Rivers Improvement Act, federal Fisheries Act, all apply to private land. So there is no significant -- we focussed on the provincial side of it yesterday, because that's where the majority of the projects are.

MR. SOMMERVILLE: What about the MNR water leasing process? That would be unique to Crown land, would it not?

MR. NORRIS: Provincial Crown land, there is a corollary under the Dominion Water Power Act for facilities on federal land, so you do get leasehold tenure again. You don't get it until the end of the process under federal land, as well.

MR. SOMMERVILLE: Okay. Does that raise any questions for anyone? Any questions arising?

MS. HELT: No questions from Staff.

MR. SOMMERVILLE: Proceed, Mr. Stoll.

FINAL ARGUMENT BY MR. STOLL:

MR. STOLL: Okay. Thank you very much.

We would like to start by thanking the Board, once again, for holding the hearing so quickly and responding to the interim relief sought, and that brings us to an issue on how we proceed as far as the implementation, which we discussed a little bit yesterday. And some of the back and forth with the Panel was we have a number of projects where the CCAs have been issued and they don't have interim relief yet. They were issued after the 25th.

And we have a number of projects that still have yet to receive their CCA, but will likely receive it within the next few weeks.

Our preference would be that any of the projects included in the application list be granted the same interim relief that has been granted to the -- in the specific interim decisions until a final decision is raised.

We feel that is administratively more efficient for people, rather than filing basically the same CCA-type documents and affidavits for every project as they come up, because I would -- we're going to continue to receive a few a week probably over the next several weeks until the list is complete.

And I am not sure and our clients aren't sure when Hydro One will be able to deliver those. So it is not that we can even group them in one or two groups and maintain -- like, so there would only be one or two interim decisions. We can't even give that assurance.

So our request is all of the projects would be granted the interim relief in the same form that has been granted to the previous projects that have been the subject of the interim decisions. And I don't know if the Board has some thoughts on that.

If the Board is not able to provide some direction to us on that today, or provide at least the same interim relief to the projects that have received their CCA but don't yet have interim relief - and those projects are listed in undertaking J1.5 in the second part of the table - then we'll turn -- then, after today, we will have to file the information.

So I will await direction on that and get into my submissions, if that is okay.

MR. SOMMERVILLE: Yes, that's fine.

MR. STOLL: Okay, thank you.

The OWA came here representing a number of its members, and what it was seeking was an alignment of the payment obligations with their particular development cycle.

And the only way we could get to that end point in a timely way was through the exemption request for the licence. They all happened to be Hydro One projects, so it only involved one distributor. We felt that was the most expedient way to get here.

But the intent was not to push costs off to the ratepayer, or to expose Hydro One to greater risk or to a greater administrative burden. We were conscious of the fact that we wanted a process that worked for us and worked for Hydro One and was fair to the ratepayer.

And that was evident and we think was evident in the exemption request as originally framed, and we think it's evident in the way we reformulated the exemption request.

And as we mentioned earlier, we have amended it to try and be more specific, and the opening words have changed so that the preamble now reads:

> "...for generation facilities for which the primary energy source is water, and for which the electrical connection is to the distribution system owned by Hydro One Networks Inc."

And we had thought about tying this to the FIT program, but that's not necessarily going to be appropriate in all cases.

As we've seen, things have changed in this province and we don't want a change in another organization to end up creating a need to amend the exemption again. So we tried to take this back to the development cycle and to the statutory obligations, so that this was not something where we would have to revisit the Board on this issue.

So I won't read in the entire exhibit. So I would just highlight that is the change and that is the philosophy on which we have made the change.

And one --

MR. SOMMERVILLE: Is that the only change that is in the document?

MR. STOLL: Yes. That's correct.

MR. SOMMERVILLE: Thank you.

MR. STOLL: And in that change, this does not cover projects that will be connected to the transmission system, and it doesn't cover other fuel sources.

So there are some limitations around -- we have scoped this. We have consciously scoped this.

And effectively the bulk of the waterpower projects are less than 10 megawatts, and will likely be in that one to 10 megawatt range, even in the future.

So we think the scoping is -- of the order is appropriate in this case.

I think the rest of my submissions are going to focus on why waterpower is different, and it goes back to the evidence we heard yesterday.

And what we heard yesterday was a discussion about the resource and the nature of the resource, both from a development point of view and also the regulatory point of view.

And what was discussed was waterpower isn't like a wind project or a solar project or other projects.

The resources there, it is a function of the flow, the drop, or the head, in other words. And it is physically where that is. We can't relocate a waterpower site. We can adjust some of the facilities, but physically the resource is where it is, where there are options to site wind farms or solar or other projects; you can move a tower. Also, you can choose a size in those projects and develop a project based on equipment that's basically off-the-rack.

There is predetermined models that are available, that you can say: I'm going to install X units of this size.

Each waterpower project is unique. And as we heard yesterday, the equipment can't be sized at the early stages. We have an idea. We have a preliminary thought on what is an appropriate design, but we -- but the developer cannot complete a detailed design for equipment order, or to provide detail and -- accurate detailed information.

We can provide information based on equipment specs, but to -- early on, but as the witnesses indicated yesterday, that's going to be subject to change, depending on what the regulatory permitting process requires of the generator.

So in that situation, we can provide information to Hydro One early on to get an indication, but there is no need for Hydro One to do anything. And in fact, it is probably a burden on them to do work at that point, because that information will change and their response to the change in information will generate more work and more time commitment.

Waterpower is also unique -- and we touched on this a few minutes ago -- as far as the vast majority of projects are on Crown land or within federal -- federally-regulated lands.

And that gives rise to other issues, rather than being on private lands, and leads us into the uniqueness of the regulatory process. And I am going to focus on the process we talked about yesterday, but as Mr. Norris indicated, the federal process is very much a similar process.

And we heard yesterday the Ministry of Natural Resources site release process is a time-consuming, long process to go through. In some cases, some of the projects have been in there three or four years.

And that process, although not an absolute requirement, is basically a precursor to be able to start an environmental assessment. Again, that's unique to waterpower.

And the MNR process also has various objectives in it, which are not included in other developments for wind or solar, even on Crown land, and that's the tie to providing socio-economic benefits to Aboriginal communities. And the negotiation and the implementation of that objective takes a significant amount of time and a significant amount of effort, especially upfront in these projects.

So in that way the lead-in to the process is very much different and very much unique to the waterpower industry. And we go through that process and we're into an environmental assessment process, which Mr. Touzel had indicated he advises his clients it takes two years. He said you might be able to do it a little bit quicker. It may take longer, but two years as a general rule. It is a significant period of time for a project to be in the environmental planning stage. And the assessment is a planning tool.

And that is a precursor to a seven to 12-month permitting stage. So after the site release or after acquisition of rights to the federal process, you are into potentially a three-year process, just to permit the site so you understand what you are going to build.

That is a process that is unlike -- the permitting process is unlike any of the other renewables or even non-renewable facilities in the province. And unfortunately, when the Green Energy Act created a number of changes, some of the changes in the timing and the ability to move to meet timelines I think was maybe a little overly optimistic, given the inundation which some of the government organizations felt with the large number of projects that came forth.

And developers of waterpower were not able to wait and really choose when they came forward with their applications, as they had been able to do under the old RESOP program. They were told: To bid into FIT, you have to rescind your connection, give up your allocation. You have to apply to FIT during the launch period with the OPA in 2009, or else you are at risk of losing the site and the resource and any of the -- and if that happens, any of the money that you have spent on the development.

And when you turn around and you are successful in getting your FIT contract, that triggered the connection process and the 90-day period to get your estimate and the six-month period to get your CCA. There is no choice in being able to push that date back to a more appropriate date for waterpower, because as we heard yesterday, the developers didn't know who was behind them. They couldn't assess the real risk of what a loss of capacity allocation would mean at that stage. They felt they had to take the meeting and had to proceed at that point.

I think the other thing that we heard yesterday -- and this, we're talking about the realities of waterpower and about the financing and the discussion we had with Mr. Lawee and the evidence he gave. And there was an exchange in which Mr. Lawee, and I will read from the transcript:

> "You need to have all of your key contracts in place, your civil contract, your turbine equipment contract and various other contracts. Your power purchase agreement must be assigned to the lender. You need lease agreements. In the case of our projects, we still have not been able to sign a Crown lease agreement with MNR.
>
> "We are working diligently to be able to get that in place, and that is one of the requirements in

order to secure our long-term financing.

"Subsequent to that, there is the waterpower lease agreement, which will get signed subsequent to the Crown lease agreement.

"There are the land surveys that need to be done on the transmission line that have to be verified by the surveyor general prior to being inserted into the Crown lease, which gets registered on title.

"Easements have to be put in place, private easements, as well as Crown easements.

"You need consents and acknowledgements from all of your key contractors. The OPA contract gets assigned. All of these civil and equipment contracts need to be assigned to the lenders.

"Until all of that is in place, the lender will not lend against the project."

So what Mr. Lawee is saying and what we heard from the panel yesterday in the exchange was that these projects have to be very mature projects before they can get debt financing, and we can't get to a mature stage through the regulatory process for a number of years.

So we're trying to align the development and permitting cycle and the ability to obtain financing with the requirements of the distribution and the exemption and time frames we're requesting. We're trying to get those in alignment so that it works for waterpower and the realities of what we faced in getting waterpower projects through the process.

So, in some cases, when we look at the contribution of the connection costs to the overall project, it is in the neighbourhood of a few percent, but, in other cases, the costs are very significant. In excess of 20 percent of the project are related to the cost.

And what's -- what the current provision of the Distribution System Code does is it forces the developer to provide 100 percent of that cost, so potentially more than 20 or 25 percent of the project cost, excluding all the costs that they're spending on permitting and other things, to be funded from equity.

And as Mr. Lawee indicated, Hydromega, they have been in this business for 25 years. They have developed projects in other jurisdictions, and they would have great difficulty and would not be able to do that.

Mr. Chan indicated that there would be projects that would be analyzed on an individual basis, and certain projects likely would not proceed on that. And part of that goes with having to fund a project four years in advance, in advance of any ability to earn revenue. There is a cost of having that capital deployed so early. And the issue is the capital does not need to be spent. It's not that we need to order the equipment or to undertake the design at that time. The money can be spent later.

And we want to align that so it makes sense for the developer, and actually will probably work better for Hydro One in the long run, because we are not forced into a situation where a lot of work gets done upfront that will need to be revisited.

I think the rest of my submissions are going to deal with a discussion about the public interest and why we feel this is in the public interest, and section 74 permits the Board and says, I quote:

> "The Board may, on the application of any person, amend a licence if it considers the amendment to be..."

And subparagraph (b), it says:

> "In the public interest, having regard to the objectives of the Board and the purposes of the Electricity Act."

And we provided some information in our prefiled evidence on the public interest and on the benefits of waterpower. I can draw your attention to Exhibit B, tab 1, and I think it begins on page 16 and carries on for about five pages.

And much of -- and Mr. Norris reiterated some of that yesterday in his testimony. And if we go back to the public interest, having regard to the objectives of the Board which are found in section 1, to protect the interests of consumers, we feel we've done that, and we feel Hydro One has confirmed that we have done that -- that our solution does that, promote economic efficiency and cost-effectiveness in the generation, transmission, distribution, sale and demand management of electricity and to facilitate the finance -- facilitate the maintenance of a financially viable electricity industry.

Again, through the alignment of the payments, we feel we've done that.

Promote the use and generation of electricity from renewable energy sources, we feel we've done that, too, because, as we heard, certain projects will not happen if the change does not occur.

So in keeping in mind what the objectives of the Board are, we feel we've met those objectives in what we proposed and the exemption that we're requesting.

If we look towards the Electricity Act and the purposes of the Electricity Act, we feel we have hit a number of those:

> "ensure the adequacy, safety, sustainability and reliability of the electricity supply in Ontario... to promote the use of cleaner energy sources and technologies, including alternative energy... and renewable energy sources, in a manner that is consistent with the policies of the Government of Ontario."

I will come back to that in just a minute.

> "To provide generators, retailers and consumers with non-discriminatory access to transmission and distribution systems in Ontario;
>
> "to protect the interests of consumers with respect to prices and the adequacy, reliability and quality of electricity service;
>
> "to promote economic efficiency and

"...sustainability in the generation, transmission, distribution and sale of electricity..."

And Mr. Norris summarized that yesterday and he talked about the durability, the reliability, the cost competitiveness of hydro relative to other fuels, the history that hydro has had in this province of providing the backbone of the economy by being able to meet the changing demands of our electricity system.

In our prefiled evidence, we reference some of the comments of the long-term energy plan, which new hydro projects complement other renewable initiatives and help to eliminate coal by 2014.

The Minister of Energy and Infrastructure:

"Waterpower has been helping fuel Ontario's growth since before Confederation and is the backbone of our renewable supply.

"Waterpower is a reliable, clean, local and naturally recurring source of energy."

It has a number of benefits: Clean, minimal greenhouse gas emissions and one of the most efficient energy technologies. It can easily respond to sudden changes in energy needs. They have long life cycles, generally 75 to 100 years. They provide water level and flow management plans provided by reservoirs and dams, can help support recreational activities and contribute to public safety and minimize flooding. Projects can provide opportunities for economic development in remote communities. It is a good complement to other intermittent forms of renewable energy, such as wind and solar.

So the government has recognized that waterpower has a place, increasing the amount of waterpower in the province has a place. Waterpower has accounted for approximately a quarter of the electricity supply last year, and there are more than 200 waterpower facilities.

As we move to integrate more renewables into our power system, the role and the importance of waterpower will increase. And I will borrow a phrase: Waterpower provides some of the battery that the electricity system needs, by being able to store water.

Integrating the renewable energy supplies requires the flexibility of every resource, including waterpower. We can't push on one lever and not affect the others.

The exemption we have asked for permits waterpower to develop. We are not asking, as I said, we are not asking for not to pay. We are not asking for the ratepayer to take on additional burdens or to burden Hydro One.

What we're asking for is an alignment of the requirements of the Distribution System Code, with the requirements and the realities of what developers are facing under a number of other proceedings and regulatory processes from other ministries and other organizations.

And we think our -- and therefore we think our exemption request is in the public interest.

And those are my submissions.

Mr. Sommerville: Thank you, Mr. Stoll.

I have a question that rises from Undertaking J1.3, which was filed today.

And it's -- I'm sure it is a technical question, and Mr. Norris, pursuant to my earlier comment, you are –- we certainly welcome your input on this.

This looks at -- one of the things represented here is the total megawatts of capacity requested. The footnote suggests that these are all figures are inclusive existing generation facilities.

So when I look at Big Beaver Falls, for example, I see a total megawatt capacity requested of 28.7. While the nameplate capacity of that project appearing on Undertaking J1.1 is -- bear with me -- 5.5. I mean, obviously it relates to some existing facilities, but could you explain the -- explain what that means?

MR. NORRIS: I can try. Board Staff asked us in one of the interrogatories to basically put together a table of available information from Hydro One, and there are two sources and I think I happen to have them both here with me.

And if you look at the sources that we referenced, one includes a list of all of Hydro One's stations, and all of the existing or current applications at those stations, that are either existing or contracted.

MR. SOMMERVILLE: Okay.

MR. NORRIS: The other one -- table includes all of the applications.

And so what we did at the request of Board Staff is to put those two tables together.

So the difference you have, for example, in Big Beaver Falls, that three or whatever megawatts would be included in the 28.717 megawatts.

MR. SOMMERVILLE: And that is really representing Kapuskasing TS?

MR. NORRIS: That's correct.

MR. SOMMERVILLE: And capacity requests that are flowing into Kapuskasing TS?

MR. NORRIS: That's correct.

MR. SOMMERVILLE: And that's not really Big Beaver Falls' contribution to that; that is the aggregate?

MR. NORRIS: Big Beaver Falls, that's correct.

MR. SOMMERVILLE: Thank you very much. That's helpful.

Ms. Helt -- Mr. Engelberg, I am assuming that you are the -- which order would you like to make any submissions you would want to make?

MR. ENGELBERG: I have no preference, Mr. Chair.

MR. SOMMERVILLE: Ms. Helt?

MS. HELT: I think perhaps if Mr. Engelberg would prefer, or doesn't mind going before me, that would be preferable.

MR. SOMMERVILLE: Let's go that way. Mr. Engelberg?

FINAL ARGUMENT BY MR. ENGELBERG:

MR. ENGELBERG: Thank you.

When the proposal was received from the applicant for an exemption for Hydro One Networks to the provisions of the Distribution System Code, Hydro One viewed the proposal with a critical eye and looked at three matters.

The first one, as I mentioned yesterday, was administrative burden. Would the proposed change slow down the process and thereby be an expense to the company and thereby ratepayers?

And Hydro One satisfied itself that that would not occur, that there would be no additional administrative burden, therefore no slowdown and no increase in costs.

Secondly, Hydro One's concern was to protect ratepayers from any costs incurred by Hydro One in advance of receiving monies from proponents, because if that were to occur, that could also harm ratepayers.

Once again, Hydro One satisfied itself that, with the proposal as it is now worded, that would not occur.

And finally, Hydro One wanted to assure itself that nothing in the proposal would harm Hydro One's ability to efficiently schedule and execute the work for these projects.

And Hydro One satisfied itself that the proposal would not do so.

So that is Hydro One's submission regarding the proposal.

MR. SOMMERVILLE: Thank you very much, Mr. Engelberg.

MR. SOMMERVILLE: Ms. Helt.

FINAL ARGUMENT BY MS. HELT:

MS. HELT: Yes. Thank you, Mr. Chair, Members of the Panel.

Staff submits that the exemption that is being requested by the OWA, as filed and then as updated as recently as this morning, should be denied.

Staff is not opposed to a limited exemption, and I will provide my reasons for that, after I clear my throat.

[Laughter]

MS. HELT: The applicant is asking the Board for an order to amend the distribution licence of Hydro One and to exempt Hydro One from, specifically, Section 6.2.4.1(e)(i) and 6.2.18(a) of the DSC for all generation facilities for which the primary energy source is water, and to substitute a special rule for these generation facilities.

As the Panel is aware, these sections of the DSC require Hydro One to execute a connection cost agreement with a generator and receive payment from the generators of 100 percent of the estimated allocated costs of connection within six months of allocating capacity to them.

Board Staff submits that the requirements of the Code were established pursuant to an extensive and thorough Code amendment process, whereby the Board noted, in the Notice of Amendment to a Code -- and that was EB-2009-0088, issued in September of 2009 -- the following, and I quote:

> "There were two overarching objectives to these proposed amendments. The first was to ensure that viable generation projects, and in particular, renewable generation projects are connected at the distribution level in a timely manner. The second was to ensure that generation projects that are not likely to proceed do not

impede the allocation of capacity to more viable projects."

Board Staff submits that these are two very important principles, and are necessary for the Board to consider when reflecting on the request being made today by the applicant.

Further, Board Staff notes that in the Code amendment process, the Board specifically considered the issue of connection cost deposits.

At page 3 of the Notice of Amendment to a Code, the Board noted that, quote:

"Cash flow and creditworthiness are issues that may arise for some legitimate project proponents in securing the necessary deposits. These costs are not disproportionate relative to overall project costs and should not be prohibitive for legitimate generation developers.

"Further, any burden to project proponents associated with raising the necessary funds or obtaining the necessary credit is outweighed, in the Board's view, by the need to ensure that capacity is allocated to projects that are most likely to be viable."

End quote. As such, Board Staff submits that the specific issue of securing funds was an issue presented and considered by the Board.

In its application, OWA is advancing the position that, absent the exemption, the timing of the payment of the connection cost deposit established by the DSC, coupled with the unique requirements to develop waterpower, will effectively prohibit significant development of waterpower in Ontario.

Staff submits that the applicant has failed to demonstrate that all the waterpower projects - and specifically all the water projects listed in their application - are unable to make the connection cost deposit payment required by Hydro One.

For this reason, Board Staff submits that an exemption for all waterpower projects of the particular sections of the DSC is not warranted, nor necessary.

My submissions will focus on the following four main points: A summary of the application and the status of the waterpower proponents' claims as set out in the notice and as described through the evidence put forward yesterday during the hearing.

The second area I will make submissions on relate to the principles of the Distribution System Code with respect to constraints, capacity allocation and attrition; the third area, potential prejudice to other renewable energy projects, including other hydro power projects, should what I will term a blanket exemption be granted.

And then my fourth submission will just touch briefly on the purpose of the Distribution System Code and the OPA rules.

So turning then to my first area of submission, the summary of the status of the waterpower proponents in this application, it is clear from Exhibit K1.3, which was filed yesterday, that four projects have made their connection cost deposit payment in full.

In its prefiled evidence, the OWA stated that in the majority of waterpower project cases, the date when the payment is required to be made is one to two years in advance of either Hydro One's need to expend money related to the connection, the receipt of a notice to proceed from the OPA, environmental permitting and the ability to draw on debt financing.

And, in fact, Mr. Stoll had reiterated those issues this morning.

Staff submits that despite this position put forward by the OWA, Exhibit K1.3, along with the response to various Board Staff IRs, shows that, as I stated previously, four projects are ones where the connection cost deposit has been paid in full, four projects have received OPA's notice to proceed, have no regulatory approvals pending and are in construction, and six projects are expected to satisfy regulatory requirements and arrange debt financing before the ends of the 2011 calendar year.

Next, I would like to review some of the principles of the Distribution System Code, and I will start with the principle of attrition.

Staff notes that the relief sought by the applicant in this case constitutes a departure from several principles of the Distribution System Code, the first being that of encouraging project attrition.

The changes to the Distribution System Code, in Staff's submission, came about to ensure a process of project attrition to encourage projects that are not proceeding to give up their allocation as there are other projects that could be advanced.

The Board, in Staff's submission, largely did so due to issues that became apparent in the OPA's previous program that awarded generation, that being the RESOP program.

Just by way of background, under RESOP, generators were required by the OPA to obtain a CIA before applying to the program to ensure that they had connection capacity, but some developers appeared to be obtaining capacity through the CIA process, and then not proceeding to develop their projects.

This obviously created a problem. Distribution system capacity was filling up with projects that got their CIAs quickly, but were not ready to proceed to construction and were, in Staff's submission, effectively blocking other projects from attaining capacity.

These other projects were often more mature, and that could have been by virtue of being in a better state of preparedness when applying or applying at a later stage.

Further, those with CIAs were required to pay connection cost deposits, but this was not until 12 months after getting their CIA.

Under the current FIT process, projects are now required to have their CIA completed before assigning capacity, and then once capacity allocation is assigned, the full connection cost deposit is due to the distributor six months, as opposed to the previous 12 months, from the date the capacity is allocated.

Board Staff submits that based on the evidence before the Board, it is unclear whether others will be adversely impacted by the relief sought.

Specifically, in Staff's view, when considering the request before the Board, the Board needs to consider whether there are other potential proponents, for example, project applicants to the OPA, who could make use of the capacity currently allocated to the project seeking exemption, should that capacity be removed because of their inability to make the connection cost deposit required by Hydro One in accordance with the Distribution System Code.

Staff notes that it did ask for this information by way of interrogatory, specifically Interrogatory No. 3.1.4, and it also asked during cross-examination, which is noted at page 15 of the transcript. However, it was not provided by the applicant. As noted by the applicant, it is not information publicly available.

The next principle of the DSC which is important, in Staff's submission, for the Board to consider is the issue with respect to constraint.

Including capacity allocation, the FIT launch program, distribution and transmission congestion and capacity, as well as further information that may not be on the record, are important considerations for this Board to inform its decision.

With respect to the FIT launch, from October 1st, 2009 to November 30th, 2009, the OPA accepted applications for its first round of contracts awarded under the FIT program, the so-called launch period.

It came out in the evidence yesterday that all of the 27 projects that are the subject of this application were filed as a result of this OPA program and subject to the terms of that program.

This resulted in relatively early application for the CIAs, regardless of whether or not the proponent would be able to meet the consequent timelines for the OEB's processes that would result from the OPA's process.

Board Staff submits that the constraints placed by the OPA program may not have aligned with the Board's own DSC program, and, as such - and I believe the evidence put forward yesterday confirms - that waterpower proponents really then had two alternatives. One was to wait and miss a potential window of opportunity to secure capacity, or, two, apply early, and then have difficulty meeting project terms.

Given that a number of projects had started their process with MNR as far as two years before the FIT launch period, it would be reasonable to assume that's why waterpower proponents would want to take this opportunity, rather than wait for months, if not longer, for a subsequent announcement of an OPA generation procurement initiative.

With respect to capacity allocation, Board Staff notes that if a waterpower proponent is not capable of providing the connection cost deposit, the capacity allocation is released, thus eliminating the so-called problem of sitting on capacity.

As I stated earlier, there was a thorough code amendment process, where the Board determined that such an approach was advisable.

The 100 percent of the deposit to be paid at six months from the time of capacity allocation ensured a process that would be devoid of the administrative burden of a series of payments, the potential collection and compliance issues that may arise.

And I appreciate that Mr. Engelberg has indicated that there will be no administrative burden to Hydro One, nor will there be any prejudice to its ratepayers, in his submission this morning.

However, in Board Staff's submission, the financial commitment would ensure generation projects that are not likely to proceed, would not impede the allocation of capacity to more viable projects.

The need to release capacity where a proponent is not committed to development is particularly important in a number of areas of the province where the natural attrition of one large generation project may mean enough freed capacity to allow for the connection of several smaller microFIT and FIT projects, which in many locations are currently unable to connect.

Staff submits that there is no evidence that other FIT projects will not be prejudiced if an exemption is granted.

In fact, in response to Staff Interrogatory 3.1.4, the OWA stated:

> "It is precisely this lack of information, the lack of a list of other FIT projects, that results in an inability for proponents to determine the degree of risk with respect to potential loss of capacity."

During the hearing, when cross-examined with respect to this response and specifically how the OWA can put forward a position that there will be no harm to other proponents after acknowledging they do not have information about other FIT projects, Mr. Norris stated in the transcript at page 116:

> "In the absence of that information, our point was that it is difficult for, if not impossible for project proponents to assess the risk of giving up capacity."

So Board Staff submits on the one hand, they say that not knowing the list of other FIT project proponents in a way causes them an inability to assess the risk against them.

On the other hand or the flip side of that, there is an issue with respect to not being able to demonstrate that there is not going to be any prejudice to others that are waiting in the line for capacity.

With respect to Mr. Norris' cross-examination, further on that same page, that being page 116, Mr. Norris notes:

"So with respect to your second question around negatively impacting other FIT proponents, what our proposition is that in amending the HONI licence under two principles, one ensuring that we have security deposits upfront, secondly, ensuring that Hydro One is not put in a position to have to spend money that isn't deposited, we don't see that as fundamentally impacting other project proposals."

Staff submits -- and this is consistent with what has been put forward this morning by both Mr. Stoll and Mr. Engelberg -- that there may not be an impact in granting the exemption on the individual waterpower proponents themselves, nor on Hydro One, in that Hydro One has confirmed there is no administrative burden, nor on Hydro One ratepayers. But it fails to satisfy Board Staff's concern that there are other FIT proponents that may be adversely impacted.

This, then, leads to my third area of my submission with respect to potential prejudice to other renewable energy projects, including other hydro power projects.

Board Staff requested information by way of interrogatories on the capacity availability at all distribution voltage level transformation stations at which the waterpower projects would connect.

The purpose in asking these questions was, in large part, to determine whether other proponents and forms of renewable energy would be or could be prejudiced by an exemption to capacity allocation and the connection cost deposit rule set out in the Distribution System Code.

Appendix B, which has been referred to, I believe, Mr. Sommerville, in your questions this morning -- which is also noted as Interrogatory J1.3 -- provides the best information available from Hydro One as to the availability of capacity at various DS and TS stations as of early April 2011.

Staff notes that the majority of the stations listed do not face significant issues of capacity requested versus the available thermal capacity on feeders at these stations.

However, in response to Board Staff Interrogatory No. 3, the OWA noted that the information pertaining to the FIT reserve is not readily available.

The FIT reserve, to be clear, is a record of projects waiting or wanting to connect to the system, but unable to do so on account of insufficient capacity, as determined by either the OPA's distribution availability tests or transmission availability tests.

Board Staff submits its concern that while it appears there may be excess capacity based on current applications with Hydro One, as noted on Undertaking J1.3, this is only a specific snapshot in time.

There is no assurance that there are not or will not be projects in the interim that will apply for capacity allocation and not be effectively blocked by these waterpower projects if an exemption is granted.

In looking at the Distribution System Code and the OPA Rules, Staff notes that when one considers the purpose of having the connection cost deposit paid in advance, this may create some burden on the part of waterpower projects.

The projects generally are being asked to pay -- or the proponents are generally being asked to pay the connection cost deposit at the time as they applied for CIAs early in the -- or at this time, as they applied for CIAs early in their development process.

It appears, with respect to the OPA, it is also relying on the Board's process to ensure that the projects that are not ready to proceed give up their capacity allocation so that other viable projects can proceed.

By requiring a CIA early in the process, rather than when the project is better defined or established, has been identified as problematic for the waterpower proponents.

MR. SOMMERVILLE: I have a question at this point, Ms. Helt.

What the evidence seemed to suggest was not that these projects were laggards, not that these projects were dragging their feet in getting ready to connect, which I think is what the purpose is of the DSC provisions were really directed to, the idea that if proponents don't have money, a significant amount of money in the game, that they -- and it is not a game, but in the situation, that they will go to sleep, and that the capacity that they have been allocated would languish, that nobody would use it, that it would sit there doing nothing.

That is not the evidence that we heard.

The evidence that we heard was to the effect that these projects are working towards completion, but facing a series of very time-consuming regulatory exercises.

We didn't see situations where they were laggards, and it seems to me that that is a fundamental difference, is it not?

MS. HELT: Oh, it is. And I am not suggesting that they are laggards.

What Board Staff's position is, that the Distribution System Code and the amendment process that was gone through in 2009 was -- occurred for the purpose of ensuring that there is timely connection.

MR. SOMMERVILLE: Right.

MS. HELT: And the Board, during that process, did in fact take into consideration submissions from various stakeholders with respect to what may be problematic for them with respect to meeting the proposed timelines.

MR. SOMMERVILLE: That's a different argument. What you are saying there is that they had their chance. They had their chance to make their argument and the Board, in deciding the way the Distribution System Code should read, heard it and disposed of it.

MS. HELT: Yes. And that actually wasn't where I was going, although it may have come out that way.

My point is really not a suggestion that any of the proponents in the application are taking their time or not pursuing as quickly as they can. However, there will be environmental hurdles for all renewable projects. Some may be specific to hydro power. Some may be specific to wind. Some may be common to all of them.

And in Staff's submission, granting a blanket exemption with respect to all waterpower projects is not warranted, based on the information put forward by the applicant.

When considering the principles of both the Distribution System Code, as well as - and I will get into this very shortly - the public interest considerations and when looking at the statutory objectives.

MR. SOMMERVILLE: Just before you get there, let me ask you another question, in fairness, as we consider your argument.

In the event the prejudice that you are talking about to other proponents -- which is an important consideration and that is why the panel wants to really understand this properly.

The prejudice to others would consist of a situation where, if they were to be excused from the requirement to pay the entire cost of connection within six months of the execution of the cost agreement, if that was to be replaced by the schedule that is being proposed here, that other proponents would be blocked out of the situation, to the extent that the full payment has not been made and that the allocation has not been cancelled as a result of that failure.

MS. HELT: That's correct.

MR. SOMMERVILLE: Is that correct?

So my question to you is -- first of all, that's a bit of a tautology, insofar as you say, Well, the prejudice exists and that the capacity has not been cancelled, even though the projects are being reasonably diligently pursued.

Secondly, is it not the case that the new, presumably prejudiced, proponent would find themselves in precisely the same position as the current proponent in going through the regulatory processes and finding themselves in exactly the same position, so that, having sidled into the queue, they find themselves subject to precisely the same difficulties?

MS. HELT: Well, with respect to your latter point, that is a very good question, and we don't know that. We don't have evidence of that. Hypothetically speaking, that may be the case, but even with this application itself, with the 27 projects or I believe 28 now, as updated this morning, there are differences with respect to these projects.

And it is clear that although some of the environmental permits may be the same and the timelines may be the same, some projects are able to make the connection cost payment -- deposit payment, excuse me, within the time period required.

It all depends on the financial viability of the proponent, what sort of collateral it may have. And there are other considerations.

MR. SOMMERVILLE: With respect, just that financial viability, it is not financial viability that that tests. It is buoyancy. The proponents here, the applicant here, is not suggesting that they pay nothing.

The proponent here, with Hydro One's endorsement, are suggesting that they do pay a significant amount of money, and, in fact, that they pay an amount of money that aligns with the cost exposure of the utility.

But the ability to pay the entire amount, in what they are suggesting as an advanced way, doesn't test the viability of the project. It tests the absolute buoyancy of the proponent. So that proponents who have particularly generous access to capital would find themselves with no difficulty here, but other proponents who have to go to lenders and have to demonstrate to lenders that their projects are mature and developing, and so on, appropriately, they're the ones that may be prejudiced. Is that not true?

MS. HELT: Well, that may be the case. However, that goes to the point that not all of the waterpower proponents are similar. They're all different.

And so it is not evident that, you know, it is required that there be an extension of the time or a payment schedule as put forward by the applicant.

MR. SOMMERVILLE: Fair enough. Please proceed. But I thought it was --

MS. HELT: I welcome questions.

MR. SOMMERVILLE: I thought it was important for you to know what the Panel is thinking as we're considering this.

MS. HELT: I would hope you interrupt me as often as you see necessary, Mr. Chair.

MR. SOMMERVILLE: Thank you.

MS. HELT: Just with respect to, and following along the same lines with respect to your questions, Mr. Chair, concerning the timing of the payment of the connection cost deposit and the OWA's position that they be allowed to make payments in accordance with the schedule as opposed to 100 percent of that deposit due to the inability to get financing, which is dependent on obtaining various agreements in place and consents and easements and approvals and permits, when this was discussed with the witness panel during the hearing yesterday, and in response to both a Staff IR, as well as in the hearing, the OWA has confirmed that the CIA window provided by the OPA is a driver for their proponents to advance their request for the CIA.

Mr. Touzel testified that it should be addressed as coming backward from the expected commercial operation date, so that you are required to request your connection impact assessment, let's say, 36 months prior to expected connection cost deposit.

His reason for this was that you don't really have any clear handle on the exact technical specifications that you are going to ask Hydro One to comment on, and Staff recognizes this.

And the applicant submits that by requiring the deposit at the time it is required, it is premature, and is asking the Board to consider the factors contributing to why the connection request process was initiated.

The applicant has stated that, if given a choice, it would submit its request for a CIA after it received its class environmental assessment to ensure that all technical aspect information relating to the project is provided to the distributor to complete the CIA.

So Board Staff's submission is that the OWA does recognize that there -- if it was able to obtain all of the necessary permits prior to having to complete the CIA, then there would not be an issue with respect to the connection cost deposit.

However, the CIA, in Staff's submission, and the OPA program and the DSC is structured in such a way, again to encourage for all renewable energy projects, that they connect in a timely manner and that they're operational in as efficient a way as possible.

So Staff acknowledges the shortcomings that are being put forward by the OWA with respect to both the CIA process and the Distribution System Code. However, Staff submits that with respect to the principles behind both of those processes, those principles are in line with the statutory objectives, which are to ensure and facilitate the maintenance of viable, renewable energy projects, economic efficiency and cost-effectiveness.

Now, that being said, Staff did indicate at the outset of the submission that it is not -- it is opposed to a blanket exemption, but is not opposed to a limited exemption.

Staff clearly recognizes the benefits to the construction of waterpower facilities in the province of Ontario. Of the sources of renewable power in Ontario, Staff agrees with the OWA that hydroelectric is, in most cases, the most inexpensive form of renewable generation under the OPA's FIT program.

Furthermore, hydroelectric power is an important part of the supply mix and the Ontario government's Clean Air policy, particularly the move towards zero percent of power from coal, a non-renewable technology that up to a few years ago provided a significant amount of the generation mix.

Board Staff submits that the development of waterpower projects should not be hindered, but at the same time, Staff submits that the development of waterpower should not in any way prejudice other forms of generation, that may also include other hydro water -- hydro power projects that have an equivalent claim to both distribution and transmission connection access.

Staff recognizes it may not be unreasonable to argue that the relief sought may be necessary for some waterpower proponents. However, if the Board is to grant an exemption, it's Board Staff's submission it should only be done in limited circumstances, depending on the specific circumstances of each case, and should be a reflection on the unique challenge faced by the specific waterpower proponent.

In fact, the Board has taken a similar approach with respect to another matter that was recently before the Board. It was a decision in EB-2010-0229, where Hydro One filed an application seeking an Order of the Board to amend its electricity distribution licence, to allow for certain -- for exemptions from certain sections of the DSC, and one of these sections related to capacity allocation issues. And Hydro One sought an exemption from section 6.2.4.1(e)(i), as well as section 6.2.18, and there were two other sections of the DSC.

But the argument put forward by Hydro One was that the timelines provided to develop connection cost estimates and associated offers to connect for 12 large generators that have applied for connection to Hydro One's distribution system are insufficient.

In its decision, the Board noted, at paragraph 48 of that decision that it would grant the exemption, and the Board stated, quote:

> "The Board understands that other distributors may be faced with similar issues with respect to processing of applications for connection by large generators, and may also need to request exemptions. These will be addressed on a case-by-case basis."

Staff submits that if the Board does grant an exemption in this case, it should follow the same approach and consider any application on a case-by-case basis.

As I set out earlier in my submission, the evidence in Exhibit J1.2 -- which we have not yet received the updated version, but it was Exhibit K1.2, filed yesterday -- it is clear that not all of the waterpower projects face similar issues with respect to the reasons for an exemption request.

At the risk of repeating myself, there were four projects that have been able to pay the CCD in full. Fifteen applicants have received a connection cost agreement and are expected to pay the CCD in full.

In examining the evidence, it was identified that half will achieve full debt financing in 2011, and the CCD for these applicants, in most cases, except for one, is less than 10 percent of the estimated connection cost for the project.

Eight applicants have not yet received their CCA, and when they do receive it, they will be required to pay their deposit in full.

In examining the evidence of these eight applicants, two appear to be achieving debt financing in 2011. The remaining six, the debt financing is expected to occur in 2013.

So based on this summary of these various waterpower proponents, although it is clear that there are challenges, the challenges faced by all of these are not the same, and they are not all equal.

These projects are all in various stages, varying from pre-environmental assessment to full notice to proceed, to full financing, and payment of the connection cost deposit.

With respect, then, to the public interest -- and I have already touched on this in my submission -- the Board does not dispute -- or Board Staff, I'm sorry, does not dispute that waterpower is in the public interest. It is clear from our statutory framework, from the various -- from the code and other regulatory instruments.

And it is clear, in Board Staff's submission, that when considering this exemption request, the Board should consider whether or not the exemption is in the public interest.

Board Staff submits that in considering the public interest and the net benefits of allowing the exemption, the Board should also consider what is fair, and look at the principles of the DSC and the various statutory framework, which includes the principles of economic efficiency, cost-effectiveness, including the timely expansion or reinforcement of distribution systems to accommodate the connection of renewable energy generation facilities.

And in Staff's submission, that includes all renewable energy -- renewable energy generation facilities, and not simply waterpower.

MR. SOMMERVILLE: Just on that point, the notice of application in this case was cast quite broadly, and attracted interventions from the Ontario Power Authority, the Canadian Manufacturers & Exporters organization, and Hydro One.

With respect to the balance of the renewables community, there are letters of comment, one from an organization called ORTAC, and another from APPrO, which is the Association of Power Producers, both of which support this application.

Does that inform our consideration of the public interest?

MS. HELT: Well, I think they are submissions and points that have been put forward to the Board for the Board to consider, certainly with respect to this application.

And as you've noted, there was extensive notice with respect to this particular application, and other parties could have come forward.

However, that being said, it's Staff's submission that if -- with respect to what the applicant is seeking in this particular application, for what is in essence a blanket exemption for all waterpower, the Board should consider, in Staff's view, all renewable energy projects and the various types of proponents that may be impacted.

Regardless of the fact that they're not here before you, it is still a requirement, in Staff's submission, and an important one, for the Board to consider when determining what is in fact in the public interest.

MR. SOMMERVILLE: Thank you.

MS. HELT: I do have some submissions with respect to the document that has been put before the Panel this morning, which is really a further revision of Exhibit K1.4 that was put forward by the OWA yesterday.

And I am prepared to make some submissions on that at this time. However, I am not sure if the Board would like to hear those now or not.

MR. SOMMERVILLE: Why don't we hear them, and then we will take a short break, if you are comfortable with that?

MS. HELT: That's fine. I was prepared to do that.

MR. SOMMERVILLE: Just as a technical matter, I guess this really requires a new reference within the record?

MS. HELT: Well, we can note it as Exhibit K2.1 or mark it as Exhibit K2.1.

EXHIBIT NO. K2.1: FURTHER REVISION OF EXHIBIT K1.4, NEW AMENDMENT TO APPLICATION.

MR. SOMMERVILLE: Thank you. And it is the new amendment to the application.

MS. HELT: Yes. And it is an updated version of Exhibit K1.4 filed yesterday.

MR. SOMMERVILLE: Thank you.

MS. HELT: From the document - and I take it the Panel does have a copy before them - my understanding is that this is an amendment to the application that has been made by the OWA, insofar as it proposes a payment schedule between the waterpower proponent and Hydro One Networks, which would replace the 100 percent connection cost deposit which is due within the six-month period of capacity being allocated.

From the document, at paragraph 1 it is clear that there is an initial payment of $20,000 per megawatt of nameplate capacity.

Paragraph 2 provides an additional deposit in the amount of 30 percent of the total estimated cost.

Paragraph 3 provides for a construction schedule, a more accurate estimate of project cost to be provided, and payment for the estimate to be drawn from the deposit referenced in paragraph 2.

Paragraph 4, there is a final balance of the total estimate 30 days after the applicant notified Hydro it has all necessary permits.

With respect to paragraph 5, Hydro One and the proponent shall mutually agree upon an in-service date that is no later than two years after Hydro One receives the balance. Staff has a concern with respect to that paragraph and offers the following comment for the Board's consideration.

When asked about this paragraph when it was put forward as Exhibit K1.4 yesterday - and this is found in the transcript at pages 9 and 10 - I put forward the question to Mr. Lawee as follows:

> "The only other question I have is with respect to point 5 of the proposal, where the LDC and the proponent shall mutually agree upon an in-service date that is no later than two years after the LDC's receiving the balance.
>
> "Is there any possibility that that two years

will put it beyond the required commercial operation date to be within the five-year period?"

And Mr. Stoll answered that:

"It could, in certain circumstances, but that would -- and that's part of the risk mitigation of the developer, because the FIT contract provides that a developer can miss the milestone date for commercial operation but be subject to a liquidated damages payment in accordance with the contract..."

Board Staff submits that this particular section of the proposal ought to be denied and that the operation date should remain to be within the five years, as required by the DSC.

Again, this goes back to my previous submissions with respect to the principles of the DSC in ensuring that projects are to be connected and operational in a timely manner.

Board Staff is concerned that by allowing this to be an exemption to the DSC and allowing this or approving this, because I do recognize that it does relate to the actual contract, the FIT contract, and liquidated damages penalty, it would be contrary to the principle of ensuring connection in a timely -- and operation in a timely manner.

And the other submission Staff has with respect to the proposal is simply, again, that it should not include all generation facilities for which the primary energy source is water and should be limited with respect to this particular -- the waterpower proponents in this particular application, except for, in Staff's submission, the four that have already paid their connection cost deposit in full.

MR. SOMMERVILLE: So the limited exemption that you are endorsing is one that would cover 23 of the now 28 projects that are listed in the schedule?

MS. HELT: I believe it will be 23. I am not sure we have the information on the additional one that was provided, the additional project today that we have specifics and whether or not that connection cost deposit has been paid.

MR. SOMMERVILLE: When you say "today", is that the Ranney Falls?

MS. HELT: Yes, that's correct.

MR. SOMMERVILLE: That's the OPG project?

MS. HELT: Yes.

MR. SOMMERVILLE: Okay. Probably not an issue with the financial viability of that proponent.

Thank you. We will take a -- are those your submissions, Ms. Helt?

MS. HELT: Yes.

MR. SOMMERVILLE: We will take a 15-minute break and reconvene at 11:30.

MR. STOLL: Could I ask for an indulgence of maybe 30 minutes just to prepare the reply to quarter to 12:00? I don't imagine I will be very long, or does that create a problem?

MR. SOMMERVILLE: With that proviso, we will break until quarter to 12:00. The Panel does have a meeting that starts at 12:00, but I can -- we can sort of move that a little bit.

MR. STOLL: All right. I appreciate that.

MR. SOMMERVILLE: We will reconvene at quarter to.

MR. STOLL: Thank you.

MR. SOMMERVILLE: Thank you.

--- Recess taken at 11:13 a.m.

--- On resuming at 11:55 a.m.

MR. SOMMERVILLE: Thank you very much. Please be seated. Ms. Helt?

MS. HELT: Yes. Mr. Chair, I understand Mr. Engelberg would like to make a few brief submissions with respect to Board Staff's remarks, prior to Mr. Stoll.

MR. SOMMERVILLE: A little unorthodox, but go ahead, Mr. Engelberg.

MR. ENGELBERG: Thank you. I will be very brief, thank you, Mr. Chair. Less than five minutes.

Hydro One want to make these submissions in view of the fact that Board Staff raised some points that Hydro One was not aware were an issue.

Hydro One's view is that the Distribution System Code should be looked at with a purposive interpretation.

Hydro One, as an LDC, has never believed that the payment requirements that were imposed by the Distribution System Code in Section 6.2.18(a) were set for the purpose of making it artificially onerous for applicants, in order to weed applicants out on financial grounds.

Hydro One's submission is that the rules were put into place in the code to protect ratepayers, and to prevent generation proponents from gaming the system.

I submit that although there were a number of different points put forward on behalf of Board Staff, that what they all boil down to was that the payment system was put there to weed out applicants, and Hydro One's view is that that could not be the case.

And furthermore, Hydro One submits that there is no evidence put forward that the proposed solution from the OWA to match deposit payments to the time period when the work is done has anything to do with weeding out financially unviable projects.

There is no reason to believe, in Hydro One's submission, from the evidence that has been put forward, that that is what would take place, or parties who make their payments at the time that the work is being done are financially unviable, as opposed to parties who make the payments earlier.

Board Staff submissions also stated a number of times that there would be prejudice to other parties. In Hydro One's submission, the word "prejudice" has to be viewed within the legal meaning of the word "prejudice".

And the fact is that when somebody gets something that somebody else is also eligible to get, that that doesn't amount to legal prejudice. And we have to look at it within the legal sense of the word.

Finally, much was made in the submissions over what is now in the Distribution System Code and how the Distribution System Code section was drafted.

Hydro One's submission is that it is frequently the case that knowledge gained after Code rules were made is helpful in determining not only the interpretation of the code, but also whether code rules should be changed. As we all know, codes are not written in stone, and it can be very helpful after a code rule has been in place for a little bit of time to look at how it's operating and what is happening, with a view to determining whether a rule should be changed that still leaves, in effect, the purposive interpretation of the code but makes it more operationally practical.

So those are our submissions.

MR. SOMMERVILLE: Thank you, Mr. Engelberg.

Mr. Stoll?

FURTHER ARGUMENT BY MR. STOLL:

MR. STOLL: Thank you.

I would like to thank Mr. Engelberg for his eloquent words, and those reflect the thoughts of the OWA, so I don't need to deal with a number of the comments that he made.

We agree that the Distribution System Code was intended to get rid of laggards, and everybody agrees these projects aren't laggards. These projects are going through their process and they're being diligent in going through their process.

Mr. Lawee yesterday indicated he started in 2005. He was able to commence construction. He hopes to have his financing closed, and when he has his financing closed he will make the payment.

That is an appropriate, in our submission, manner of conducting business. Hydro One and the other ratepayers are protected. We're not saying -- our position isn't that we're not paying.

We also disagree that the deposit was meant to establish project viability. And we don't feel that the deposit mechanism should be used -- and Mr. Engelberg -- as an artificial barrier.

If that was going to be advanced, there should have been evidence led that the project viability and the deposit were intimately tied.

There was also some information where Board Staff referenced some of the capacity allocations, and quite frankly, the information was not provided by the OWA because it's not in our possession. We don't have control over it, and it is not publicly available.

So I deny that we had the ability to provide certain evidence, and it leads to -- one to a certain conclusion.

Also, we disagree that others would be negatively impacted. We appreciate the Board Chair bringing up the APPrO letter, and APPrO is in support of our application and representing the power producers.

Also the associations for the solar industry, the wind energy, other generators, were contacted. They chose not to participate. And we think that is evidence that they don't view this as negatively impacting their membership or other generators.

We don't think this impacts the ratepayers or negatively impacts Hydro One, and they have confirmed that.

With respect to the limited exemptions, there is an insinuation that the projects are different. And from our position, they're not different; they're going through the same cycle. Future projects will be forced through this same cycle, we heard yesterday.

Basically, the projects that are getting looked at are the ones that have contracts. If you don't have a contract, your project isn't progressing through the regulatory process and becoming more mature. It is sitting there.

So all that has happened is we brought forward 27, 28 projects that are at slightly different phases in the same development cycle. And if these projects drop off and are replaced with other waterpower projects, we will be right back here, because they'll be in the exact same position.

And the problems we faced -- because the development process is the same. The timing issues will be the same.

We heard the submissions about removing paragraph 5. We don't agree that is in the best interests of anyone, and we don't believe it reflects the reality of the situation, in that that date is not necessarily tied to the FIT completion date. It is tied to the timeframe, but as we heard, the milestone dates are not necessarily exactly the same. So paragraph 5 was to recognize the reality, to provide some protection to Hydro One in certain circumstances, and to permit the projects to proceed in a timely manner.

Everybody wants good projects to proceed in a timely manner. We all agree with that.

And fundamentally, that is why we're here, but fundamentally, waterpower is different, and the timely manner for waterpower is at least five years, sometimes more. Not for reasons of lack of diligence on the developer, but that is just the nature of the beast.

And from our perspective, the system should not be set up to preclude projects that are going through in a diligent manner from proceeding.

Those are our submissions. And if I could just -- we had asked about the limited exemption. I was wondering if the Panel had some words they could offer about the interim relief we had mentioned earlier.

MR. SOMMERVILLE: The Board is going to adjourn for a period of an hour and 10 minutes, during which the Board will be considering the nature of any exemption that may issue from this proceeding.

So we will adjourn until about ten after 1:00, and we may be in a position to issue a decision at that time, and we will advise the parties at that point as to whether we have been able to do that or whether we will have to further defer our decision and come back to the subject.

So unless there is something that anybody wants to raise, we will stand down until 1:10 p.m. Mr. Engelberg?

MR. ENGELBERG: I would like to take this opportunity to mention one thing. It is not by way of argument, but because of the raising just now of this matter of point number 5 in --

MR. SOMMERVILLE: Yes.

MR. ENGELBERG: -- K2.1, I checked with my client and was told that it would create a problem for Hydro One if item 5 were not granted as part of the relief, if relief is to be granted, because Hydro One could find itself really jammed at the last minute. If there were a project that was four-and-a-half years out, there was only six months left and everything had to be done within six months, it would be virtually impossible.

MR. SOMMERVILLE: Okay. Thank you for that. The Board will take that into consideration as we go forward. Any response to that, Ms. Helt?

MS. HELT: No, Mr. Chair.

MR. SOMMERVILLE: Thank you. I take it you don't have any response to that, Mr. Stoll?

MR. STOLL: I do not. Thank you.

MR. SOMMERVILLE: So we will stand down until 1:10. Thank you very much.

--- Luncheon recess taken at 12:05 p.m.

--- On resuming at 1:21 p.m.

MR. SOMMERVILLE: Thank you very much. Please be seated.

The Board has arrived at a decision.

DECISION:

MR. SOMMERVILLE: After considering all of the evidence and the submissions, the Board has been persuaded that a general exemption to the licence of Hydro One should be granted.

In coming to this conclusion, the Board is mindful that proponents of hydroelectric projects located on Crown land within the province of Ontario, or federally-regulated lands, experience a unique set of circumstances which can impair their ability to meet some of the obligations created by the Distribution System Code and the FIT program.

This is not an exemption request seeking relief from paying the connection costs. It is about aligning the payment obligations with the particular development and regulatory approval cycle of hydroelectric projects.

The Board has heard evidence that the development of hydroelectric projects is largely unique relative to other types of renewable generation, for two reasons.

The first is that they are relatively site-specific, and involve an iterative design process, in that the specifications are subject to change as a result of the regulatory permitting processes. And those regulatory permitting processes are serially impacted by evolution within the project.

The second reason is the extensive approval processes where provincial, Crown or federally-regulated lands are involved. The processes of various levels of government, while expedited, we are sure, to the extent reasonably possible, still can create circumstances where securing financing from third parties for hydroelectric projects in the timeframes required under the rules of the Distribution System Code and those governing the FIT program, can be difficult.

Lenders may reasonably be unwilling to extend significant financing when projects are still facing important regulatory hurdles and project uncertainty.

Even where financing is not an issue, the requirement to fund projects so far in advance of commercialization seems, in some cases, unreasonable. The Board also notes that the DSC and other regulatory aspects of this new renewables regime already acknowledge that there is a difference in timelines associated with water generation development as compared to other renewable energy projects.

The Board is appreciative of the role of Hydro One -- that Hydro One Networks has played in this proceeding. Hydro One has very constructively engaged with the applicant to arrive at a structure for the exemption codified in Exemption K2.1 (sic), which protects the interests of ratepayers, Hydro One and the hydroelectric developers.

Hydro One has explicitly endorsed this approach.

The Board knows, as was very clearly and ably expressed by Board Staff, that the purpose of the DSC provision from which relief is sought is to eliminate projects that are not being pursued aggressively or reasonably by the proponents.

Capacity allocation is a very serious step, and proponents who do not aggressively pursue commercialization of their projects should be removed from the process.

This is what the DSC provision is intended to accomplish.

The Board does not see the exemption sought by the applicant in this case as compromising this objective. In fact, what we heard was that these projects are being diligently pursued by their proponents through a unique, time-consuming and costly array of regulatory milestones.

The Board is concerned that maintaining the current requirement of Section 6.2.18(a) of the DSC may actually have the effect of freezing capacity inappropriately, which is precisely what the provision is intended to avoid.

If water proponents are thwarted by this requirement, their successors are likely to face the same obstacles that they have.

The Board recognizes, and all parties in this proceeding agree, that hydroelectric generation is an important component of the province's supply mix, and obstacles to its development need to be addressed. This is not at the expense of other renewable projects, and that is not the case here.

The Board notes that while notice in this proceeding was extremely inclusive, no representatives of other forms of generation or other stakeholders saw fit to oppose this application. In fact, one association of generators supported the application through letter of comment.

Board Staff emphasized that the DSC Code revisions were the product of an extension -- extensive consultation process. The argument of Board Staff is that Board should be reluctant to unseat requirements arrived at through such a process. The Panel agrees, but considers that in this case we have been presented with practical examples of how the policy may have unintended consequences for this narrow category of generation developers, which could not have been foreseen by the drafters of the amendments in September 2009.

The Board would like to be clear that the exemption provided for in this case is strictly limited to hydroelectric projects between one and 10 megawatts in nameplate capacity, that are located on provincial, Crown or federally-regulated lands, and which are connected to the distribution system owned by Hydro One, and that it is not intended to extend to any other category of developers.

The Board accepts the proposal agreed to between OWA and Hydro One as drafted, with the exception of narrowing the category of projects as previously articulated.

The interim exemptions granted leading up to the oral hearing in this proceeding, shall be deemed to be subject to the revised provisions articulated in Exhibit K2.1.

The decision is effective today, negating any need for additional interim licences. The Board will issue Hydro One an amended licence in due course.

The Board notes that CME has participated in this proceeding and has been deemed eligible for a cost award. CME is to file any cost claims by May 12th, 2011. Any concerns with the cost claim filed by CME must be received by May 19th, with CME given until May 26th for a reply.

Are there any questions arising from the decision?

My colleague advises me that I may have misspoken when I referred to exemption 2.1. In fact, what I mean to say is Exhibit 2.1. Thank you for that clarification.

So it is Exhibit 2.1, which was filed today, which represents the latest amendment to the application.

MR. STOLL: Just the upper boundary, was that 10 and under, or less than 10?

MR. SOMMERVILLE: Including 10, 10 and under.

MR. NORRIS: And down to zero?

MR. STOLL: No. I think --

MR. SOMMERVILLE: Between one and 10.

As the Board reviewed the evidence in this case, that comprised all of the components, I believe.

MR. NORRIS: No. No, it didn't.

MR. SOMMERVILLE: There was one that was less?

MR. STOLL: Yes.

MR. NORRIS: I would just observe for those 500-kilowatt or 800-kilowatt facilities, it is the same issue. So if it would be 10 and under, that would capture everyone.

MR. SOMMERVILLE: The Panel is fine with that correction.

MR. NORRIS: Thank you.

MS. HELT: Mr. Chair, perhaps it would be helpful if the OWA re-submits, then, it's Exhibit K2.1, with the further clarification as set out in your decision?

MR. SOMMERVILLE: That would be -- I think that is a desirable step.

Hydro One can also review that and make sure that it captures all of the amendments that we've talked about.

MR. STOLL: We will circulate it to Hydro One, as well.

MR. SOMMERVILLE: Thank you.

MR. STOLL: Okay.

MR. SOMMERVILLE: Is there anything further?

Thank you very much. The Panel would like to express its appreciation for the witnesses, who were very forthright in their testimony and provided the Board with very good information.

Hydro One, we've spoken in the decision of the very constructive attitude that you have taken in this, and that's very much appreciated, and I think was very -- was instrumental in arriving at what the Panel thinks is a very positive outcome.

And also Board Staff, that took a very principled position on this subject, and which argued ably and cross-examined very effectively, and was of great assistance to the Board in reaching its conclusions.

So thank all of the parties for that. Thank you.

--- Whereupon the hearing concluded at 1:30 p.m.

9394947.1

Exhibit "B"

Tab 1, Schedule 6

FIT Contract (Form of Agreement)

Filed separately