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Frank D'Andrea
Vice President, Regulatory Affairs & Chief Risk Officer

BY EMAIL, RESS AND COURIER

January 24, 2020

Ms. Christine E. Long
Board Secretary
Ontario Energy Board
Suite 2700, 2300 Yonge Street
P.O. Box 2319
Toronto, ON M4P 1E4

Dear Ms. Long,

EB-2018-0275 – Niagara Reinforcement Limited Partnership Application for 2019 Interim Revenue Requirement - Responses to OEB Staff Interrogatories

Please find attached Niagara Reinforcement Limited Partnership ("NRLP")'s responses to supplementary interrogatories received from OEB Staff dated January 10, 2020.

An electronic copy of this has been filed through the Ontario Energy Board's Regulatory Electronic Submission System (RESS) and two (2) copies will be couriered to you shortly.

Sincerely,

ORIGINAL SIGNED BY FRANK D'ANDREA

Frank D'Andrea

OEB INTERROGATORY #1

Reference:

(1) Letters of Comment
(2) Filing Requirements, pages 11 & 13, sections 2.3.2 & 2.3.4

Interrogatory:

Preamble:

OEB staff notes that NRLP has not received any letters of comment to date regarding this proceeding. However, sections 2.3.2 and 2.3.4 of the Filing Requirements[1] indicate that transmitters are expected to file with the OEB their response to the matters raised in any letters of comment sent to the OEB related to the transmitter's application.

Question:

Going forward, please ensure that any responses to letters of comment or other applicable correspondence that may be received are filed with the OEB. Such correspondence must be filed before the argument (submission) phase of this proceeding.

Response:

NRLP will comply with the filing requirements.

[1] Filing Requirements For Electricity Transmission Applications Chapter 2 Revenue Requirement Applications, February 11, 2016

OEB INTERROGATORY #2

Reference:

(1) Decision and Order EB-2004-0476, page 9
(2) Exhibit B, Tab 2, Schedule 1, page 1
(3) Exhibit B, Tab 2, Schedule 1, page 6

Interrogatory:

Preamble:

At the above noted reference (1), the OEB provided the following findings with respect to Hydro One's section 92 application to construct the transmission asset for which NRLP is now seeking approval of its 2020-2024 Transmission Revenue Cap Incentive Rate-Setting Application (the Application):

> *First, leave to construct in this case is granted without a determination that the Applicant has proven the financial benefits of the Project. As a result, this decision cannot be taken as a finding that the costs of the Project are appropriately recovered from ratepayers. Hydro One will have to demonstrate this when seeking to recover those costs in the future.*

In the Application, at reference (2), NRLP states:

> *In assessing the transfer of assets from Hydro One Networks Inc. to NRLP, the OEB made the following finding:*
>
> *The OEB finds that the proposed transfer is reasonable and is not anticipated to have any negative effects. However, for greater clarity, the OEB notes that the leave to sell the NR [Niagara Reinforcement] Assets does not constitute an approval of the value of the NR Assets for the purpose of rates or any entitlement of NRLP to recover the full cost of the assets. The prudence of the cost of these assets will be determined by the OEB in the future transmission rate proceedings. [Quote from Decision and Order EB-2018-0276, September 12, 2019]*

At reference (3), the Application states:

> *HONI also submits that the expenditures were prudent given the significant benefits to Ontario's ratepayers from (a) providing increased supply capacity, (b) reducing transmission line losses and (c) facilitating outage reliability in the Niagara region.*

The OEB has issued *Filing Requirements For Electricity Transmission Applications – Chapter 4 – Applications under Section 92* (Filing Requirements) that are intended to assist applicants during their preparation of leave to construct applications. Page 4 of the Filing Requirements states the following with respect to how the OEB assess such applications:

> *In determining a leave to construct application, the Board seeks information about the project and evaluates whether it is in the public interest taking into consideration aspects of:*
> *a) Price;*
> *b) Reliability;*
> *c) Quality of electricity service; and*
> *d) Promotion of the use of renewable energy sources.*

The OEB has not made a determination to date if the Project's construction costs were prudent. The questions that follow have been designed to allow the OEB to better assess the prudence of the costs in respect of which NRLP is seeking inclusion in its rate base and cost recovery.

Questions:

a) In accordance with the Filing Requirements, please provide the information necessary for the OEB to assess the prudency of the Project's costs. At a minimum, this should include, but may not be limited to, the following:

   i. **Cost-benefit analysis**: evidence of the various options that were considered by the applicant as alternatives to the NRLP project (*Filing Requirements, Page 9*). Please note that as a "Discretionary Project", the cost-benefit analysis completed by NRLP must include a comparison against the "doing nothing" scenario.

ii. **Qualitative benefits**: if the project is expected to have significant qualitative benefits that cannot reasonably be quantified, evidence about these qualitative benefits must be provided. (*Filing Requirements, Page 10*).

iii. **Quantitative benefits:** where an applicant attributes market efficiency benefits to a proposed project, such as lower energy market prices, congestion reduction, or transmission loss reduction, the evidence submitted must include quantification of each of the market efficiency benefits listed for that proposed project. (*Filing Requirements, Page 10*).

b) Please provide additional support for NRLP's statements on the need for and the prudence of the costs for the project with respect to "the significant benefits to Ontario's ratepayers from (a) providing increased supply capacity, (b) reducing transmission line losses and (c) facilitating outage reliability in the Niagara region."

<u>Response:</u>

a) In responding to this interrogatory, NRLP provides the following context:

Hydro One filed the Niagara Reinforcement Project (NRP) leave to construct application on October 29, 2004, and approval was granted by the OEB on July 8, 2005. The OEB at that time did not have filing requirements in place for the development of transmission infrastructure that would require leave to construct approval[1].

Nonetheless, NRLP is cognizant of the conclusions of the OEB in the Leave to Construct application, as provided in Reference 1. To that end, and to assist Board Staff, NRLP provides the following information.

The NRP was considered against a do-nothing alternative in the original leave to construct application. Documentation on the cost-benefit analysis or benefits of the Project in general, was provided in the following exhibits in the original leave to construct application:

- Exhibit B, Tab 3, Schedule 1 – Alternatives Considered

[1] EB-2006-0170- Staff Proposal on the Minimum Filing Requirements for Transmission and Distribution Rate Applications and Leave to Construct Projects was released on July 17, 2006.

- Exhibit B, Tab 3, Schedule 2 – Summary of Alternatives Considered
- Exhibit B, Tab 4, Schedule 3 - Assessment of Consumer Benefits: A Summary of Hydro One's GEMAPS Study
- Exhibit B, Tab 4, Schedule 10 - Calculation of Line Losses and Energy Savings
- Exhibit B, Tab 6, Schedule 2 – IMO Notification of Approval and System Impact Assessment
- Exhibit B, Tab 6, Schedule 3 – Customer Impact Assessment

These exhibits are provided as Attachments 1 through 6, respectively, to this interrogatory response in the order outlined above.

At the time of the LTC filing the OEB determined it was not in a position to make a determination on whether the Project is in the public interest with respect to price because it could not determine the net costs of the Project. In so doing, the OEB decision was predominantly premised on two points: (1) quantifying the benefits of reliability was and remains inherently difficult, and (2) there was a lack of coordination between the IESO, OPA, and Hydro One which the OEB conceded was understandable given the newness of the institutional arrangements at the time (this was just after the break-up of Ontario Hydro).[2]

The construction costs of the Project are now known, $135.2M[3]. In addition to being a transmission project that has been partnered into by indigenous communities which aligns with the intention of the Ontario Long Term Energy Plan, the corresponding system benefits of the Project, as also documented by the IESO, have been reaffirmed and articulated in the post-filing documents provided by Hydro One on the status of the NRP. This was provided to the OEB on April 4, 2018. This letter is re-submitted as Attachment 7 of this interrogatory response and an extract is provided below for ease of refernece.

"The Niagara Interface and Queenston Flow West interface are critical corridors for moving supply into the province, as it facilitates the importing and exporting of

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[2] EB-2004-0476 – OEB Decision and Order – Page 8
[3] EB-2018-0275 – Exhibit B, Tab 2, Schedule 1 – Page 4, Table 1. Note that only $119.4M of the in-service additions will be added to the NRLP rate base per Exhibit C, Tab 1, Schedule 1 of this Application.

power between New York state and Ontario. The existing Niagara transmission capability can limit imports via the New York interties and at times can constrain the hydroelectric generation in Niagara. Limitations on the 230kV Niagara transmission capability restrict any significant new renewable or clean energy development in the Niagara area. In the last Large Renewable Program (LRP) procurement, the Niagara area was a restricted zone for prospective projects. NRP increases the number of 230kV circuits connecting the Niagara area system to the rest of Ontario from five to seven. The IESO's 18-month Outlook "An Assessment of the Reliability and Operability of the Ontario Electricity System" released on March 21, 2018 confirms that transmission congestion continues to restrict generation in the Niagara region and that the NRP project once completed, will increase the transfer capability to the rest of the Ontario system by approximately 700 MW.[4]

NRP will allow for more cost effective and timely refurbishment of the very critical Sir Adam Beck II transmission station which connects the Beck generation and the interconnections with New York. Because of the high utilization and criticality of the 230kV Niagara transmission circuits there are significant limitations for outages that results in complex and lengthy refurbishment work at the Beck II station. NRP will significantly alleviate such limitations such as outage durations at Middleport TS[5]".

Information on the quantitative and qualitative benefits of the Project is documented again for ease of reference in response to part b of this interrogatory.

b) The IMO's System Impact Assessment provided at Exhibit B, Tab 6, Schedule 2 of EB-2004-0476, concluded that "the proposed project will enhance the power transfer capability of the Queenston Flow West (QFW) interface to approximately 2,534 MW, which is approximately 800 MW more than the existing capability. The enhanced transfer capability with all elements in service will allow the unconstrained operation of the existing Beck generation facilities within the Niagara zone, improve the utilization of New York–Niagara import capability, and provide limited room for generation expansion within the Niagara zone."

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[4] IESO's 18-month Outlook *"An Assessment of the Reliability and Operability of the Ontario Electricity System"* , page 29

[5] In the 2003 Blackout, a key breakup of the Ontario system occurred over the Niagara 230kV circuits because the Niagara generation complex is more strongly coupled to New York than Ontario. This was a contributing factor for upper state NY to stay intact while Ontario did not. During major system disturbances and islanding conditions, hydroelectric generation is the most robust source of generation to maintain system stability.

At the time of the LTC filing, the NRP was expected to reduce power losses on the QFW interface by between 10,500 MWh and 22,750 MWh (depending on the magnitude of the flows across the interface) (EB-2004-0476 Exhibit B, Tab 1, Schedule 1).

Additional capability for the QFW interface will also improve the reliability of supply within Ontario. The incremental 800 MW shortens the time required to re-establish electricity supply after possible black-outs or load shedding events.

TRANSMISSION ALTERNATIVES CONSIDERED

To address the needs identified in Exhibit B, Tab 1, Schedule 1, the former Ontario Hydro initiated a process of obtaining environmental approval for a reinforcement of the transmission system in the Niagara region. In 1998, the Ministry of the Environment (MOE) granted approval to the former Ontario Hydro for the transmission line upgrade. A summary of the environmental assessment approval process is provided in Exhibit B, Tab 6, Schedule 6. The transmission-related aspects of this approval included the preferred route called the Southern Double Circuit 230 kV line, as shown on the map in Exhibit B, Tab 2, Schedule 2.

This exhibit describes the alternatives considered in the process of developing this submission.

Alternative 1: The Niagara Reinforcement Project (NRP)

The route and facilities comprising the NRP are described in Exhibit B, Tab 2, Schedule 1. This route follows rights-of-way as prescribed by the EA approval. The facilities proposed in the NRP are consistent with those proposed in the EA application and remain well within the scope of the EA approval.

Alternative 2: Status Quo

The Status Quo alternative accepts that the existing facilities comprising the QFW Interface would remain unchanged, thus limiting the interface to 1800 MW based on summer planning rating. Accordingly, the benefits associated with the NRP would not materialize.

A Comparison of the Two Alternatives

The NRP was compared to the Status Quo alternative. Since the costs and benefits of the Status Quo alternative are zero, this economic comparison of alternatives resulted in an evaluation of the costs of the NRP vis-à-vis its benefits with respect to energy costs and line losses.

A summary and details of this economic comparison are provided in Exhibit B, Tab 3, Schedule 2 and Exhibit B, Tab 4, Schedule 4, respectively. According to the economic analysis presented in these exhibits, the overall NRP project cost is expected to be recovered within three years (pre-tax) based on the energy savings to ratepayers.

In addition, the NRP enables Hydro One to address the needs identified in Exhibit B, Tab 1, Schedule 1. These needs include provision for increased interconnection capability, facilitating the development of additional generation in the Niagara region, reductions in restoration time following interruptions and improved transmission system flexibility.

Recommendation

Based on the discussion above, the NRP plan is the recommended alternative.

TABLE SHOWING SUMMARY COMPARISON OF ALTERNATIVE TRANSMISSION PLANS

Alternative	**Cost** (1)	**Estimated Impact on Existing Tx Rates** (2)	**Estimated Ratepayer Energy Cost Savings (Summer Only)** (3)	**Estimated Reduction in Losses** 2007 PV of Losses at $0.5 M/yr to $1.1 M/yr for 2007-2010 (4)	**Estimated Ratepayer Payback Period (Pre -Tax)** (5)
NRP – Build Double Circuit 230 kV Line	Project Costs: $116 M	Approx 2.0% increase in Network Tariff beginning in 2008	Over $60 M annually from 2007 through 2010.	$1.8 M to $3.9 M	Less than 3 years
Status Quo	Nil	No Rate Impact	No Savings	No Improvement	Not Applicable

Notes:
(1) For details, see Exhibit B, Tab 4, Schedule 2.
(2) For details, see Exhibit B, Tab 4, Schedule 5.
(3) For details, see Exhibit B, Tab 4, Schedule 3.
(4) For details, see Exhibit B, Tab 4, Schedule 10.
(5) For details, see Exhibit B, Tab 4, Schedule 4.

ASSESSMENT OF CONSUMER BENEFITS: A SUMMARY OF HYDRO ONE'S GEMAPS STUDY

As noted in Exhibit B, Tab 1, Schedule 1, the existing capability of the Queenston Flow West (QFW) interface at times, results in congestion that prevents lower-cost energy in the Niagara Zone from becoming available to the rest of the Province.

This Schedule provides a summary of the methodology used in evaluating the energy cost savings to the electricity consumers of the Province due to the Niagara Reinforcement Project (NRP). The assessment was carried out using an industry-recognized program for simulating electricity production costs, known as GE Multi-Area Production Simulation (GE MAPS). The GE MAPS model is the anayltical tool for modelling the interaction of electric transmission and generation. The model permits detailed simulation of the operation of the transmission system, taking into account the dynamic interactions among generating units and the transmission system, rather than simplifying the transmission system into a system of 'pipes" with independent, fixed capacity. GE MAPS uses Ontario and northeastern US transmission system models, and Ontario and US generators' production costs, in conjunction with Local Marginal Pricing (LMP) methodology, to assess the impact of an 800 MW improvement on the QFW interface resulting from the NRP.

The purpose of the study was to estimate the economic benefits of the proposed upgrade to Ontario consumers from the planned in-service date of 2007 through 2010. Although the NRP will result in savings year-round, the bulk of these savings are expected to occur during the summer months. Accordingly, the study assessed potential savings from the summer months only. The findings indicate that energy cost savings for Ontario ratepayers are expected to exceed $60 million (in 2007 dollars) for each of the four years. These results were based on the following "base case" assumptions:

- Ontario's load forecast is in accordance with the IMO demand forecast as shown in Exhibit B, Tab 4, Schedule 8.
- US area load forecasts are in accordance with the GE MAPS database (issued in 2004).
- No new interconnections exist between Ontario and other jurisdictions.
- Five of eight Pickering Generating Station (GS) nuclear units and six of eight Bruce GS nuclear units are in-service.
- Lakeview GS is out of service.
- All remaining coal-fired GS's in Ontario are in-service (a conservative assumption, recognizing that the Ontario Government plans to shut down these GS's in the near future).
- An additional 50 MW of power output and 1.1 TWh of energy output from Beck GS will become available in 2009 as a result of the new tunnel.

The remaining coal-fired GS's represent about 6,500 MW of the generation in Ontario. When these plants are shut down according to the Ontario Government's plan, the following two most likely scenarios may occur to replace their output:

Scenario 1 – Nuclear and Natural Gas Generation Increase

- One more Pickering GS unit and the two remaining Bruce GS units returned to service, resulting in approximately 2,100 MW.
- New natural gas units around the GTA, resulting in approximately 2,200 MW.
- New renewable generators around the Province, resulting in approximately 300 MW.
- Demand Side Management throughout the Province, resulting in approximately 1,300 MW.
- New generation projects in the vicinity of existing coal-fired plant sites, resulting in approximately 600 MW.

Scenario 2 – New Natural Gas Generation Increase

- New natural gas units around the GTA, resulting in approximately 2,200 MW.
- New renewable generators around the Province, resulting in approximately 300 MW.
- Demand Side Management throughout the Province, resulting in approximately 1,300 MW.
- New generation projects in the vicinity of existing coal-fired plant sites, resulting in approximately 2,700 MW.

For both scenarios, the 800 MW NRP will result in higher savings for Ontario ratepayers than those estimated using the "base case" assumptions.

CALCULATION OF LINE LOSSES AND ENERGY SAVINGS

1.0 INTRODUCTION

Electric power loss is the energy dissipated as heat whenever power flows through an electrical transmission line conductor. The losses are proportional to the square of the electrical current flow in the lines.

The NRP will reduce electrical current flow in each of the pre-existing circuit of the QFW interface when the new circuits of the NRP are in-service thus resulting in reduced power losses.

2.0 METHODOLOGY

The evaluation compares losses for cases with and without the NRP facilities. Power losses were calculated for the 230 kV lines in the portion of the transmission system bounded by the Allanburg TS, Beck GS, Beach TS, Burlington TS and Middleport TS. The loss evaluation first calculated power losses (MW) without NRP facilities in-service; secondly, without changing generation dispatch or loads power losses (MW) were calculated with the NRP facilities in-service. The difference between the power losses in both scenarios represented the losses reduction due to the NRP facilities.

3.0 RESULTS

Since the QFW interface flow varies significantly throughout a year, power losses were calculated for the two system conditions. The first study case examined an average QFW interface flow of approximately 900 MW. For this case, the NRP plan produced a 10,500 MWh loss reduction. The second study examined an average QFW interface flow of approximately 1,160 MW. For this case, the NRP plan produced a 22,750 MWh loss reduction. Based on an average energy price of 5 cents/kWh, the resultant value of the energy savings from the NRP plan was estimated to range between $0.5 million to $1.1 million per year for the respective cases described above.

IMO Independent Electricity Market Operator

October 26, 2004

Mr. Bing Young
Manager, Transmission System Planning
System Development Division
Hydro One
483 Bay Street
Toronto, Ontario, M5G 2P5

Dear Mr. Young:

Queenston Flow West (QFW) Transmission Reinforcement Project
Notification of Approval of Connection Proposal
CAA ID Number: 2002-085

Thank you for participating in the IMO's Connection Assessment and Approval process.

The connection assessment that was requested to evaluate the impact of this proposed project is now complete. The IMO has determined that the proposed changes would not have any adverse effects on the reliability of the IMO-controlled grid assuming the IMO requirements detailed in the System Impact Assessment report are met, and is therefore pleased to grant **conditional approval** of the proposed connection.

Final approval to connect onto the IMO-controlled grid will be granted upon successful completion of the IMO Facility Registration process. During the registration process, the applicant will be expected to demonstrate that the IMO requirements listed in the SIA report have been fulfilled.

A copy of this Notification of Approval, together with a copy of the System Impact Assessment Report will also be provided to the Ontario Energy Board (OEB). A further copy of the Report will be posted on the IMO web site: www.theimo.com.

For further information, please contact the undersigned.

Yours truly,

RS Gibbons

Bob Gibbons
Manager - Long Term Forecasts & Assessments
Telephone: (905) 855-6482
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E-mail: bob.gibbons@theimo.com

cc: IMO Records

IMO_REP_0220

CONNECTION ASSESSMENT & APPROVAL PROCESS

System Impact Assessment Report
Queenston Flow West (QFW) Transmission Reinforcement

Applicant: Hydro One Networks Inc.

CAA ID *2002-085*

Long Term Forecasts & Assessments Department & Consistent Information Set Department

October 26, 2004

System Impact Assessment Report

QFW Reinforcement

Acknowledgement

The IMO wished to acknowledge the assistance of Hydro One in completing this assessment.

Disclaimers

IMO

This report has been prepared solely for the purpose of assessing whether the connection applicant's proposed connection with the IMO-controlled grid would have an adverse impact on the reliability of the integrated power system and whether the IMO should issue a notice of approval or disapproval of the proposed connection under Chapter 4, section 6 of the Market Rules.

Approval of the proposed connection is based on information provided to the IMO by the connection applicant and Hydro One(s) at the time the assessment was carried out. The IMO assumes no responsibility for the accuracy or completeness of such information, including the results of studies carried out by Hydro One(s) at the request of the IMO. Furthermore, the connection approval is subject to further consideration due to changes to this information, or to additional information that may become available after the approval has been granted.

Approval of the proposed connection means that there are no significant reliability issues or concerns that would prevent connection of the proposed facility to the IMO-controlled grid. However, connection approval does not ensure that a project will meet all connection requirements. In addition, further issues or concerns may be identified by the transmitter(s) during the detailed design phase that may require changes to equipment characteristics and/or configuration to ensure compliance with physical or equipment limitations, or with the Transmission System Code, before connection can be made.

This report has not been prepared for any other purpose and should not be used or relied upon by any person for another purpose. This report has been prepared solely for use by the connection applicant and the IMO in accordance with Chapter 4, section 6 of the Market Rules. The IMO assumes no responsibility to any third party for any use, which it makes of this report. Any liability which the IMO may have to the connection applicant in respect of this report is governed by Chapter 1, section 13 of the Market Rules. In the event that the IMO provides a draft of this report to the connection applicant, the connection applicant must be aware that the IMO may revise drafts of this report at any time in its sole discretion without notice to the connection applicant. Although the IMO will use its best efforts to advise you of any such changes, it is the responsibility of the connection applicant to ensure that the most recent version of this report is being used.

Hydro One

The results reported in this study are based on the information available to Hydro One, at the time of the study, suitable for a system impact assessment of this transmission system reinforcement proposal.

The short circuit and thermal loading levels have been computed based on the information available at the time of the study. These levels may be higher or lower if the connection information changes as a result of, but not limited to, subsequent design modifications or when more accurate test measurement data is available.

This study does not assess the short circuit or thermal loading impact of the proposed facilities on load and generation customers.

In this study, short circuit adequacy is assessed only for Hydro One breakers. The short circuit results are only for the purpose of assessing the capabilities of existing Hydro One breakers and identifying upgrades required to incorporate the proposed facilities. These results should not be used in the design and engineering of any new or existing facilities. The necessary data will be provided by Hydro One and discussed with any connection proponent upon request.

The ampacity ratings of Hydro One facilities are established based on assumptions used in Hydro One for power system planning studies. The actual ampacity ratings during operations may be determined in real-time and are based on actual system conditions, including ambient temperature, wind speed and facility loading, and may be higher or lower than those stated in this study.

The additional facilities or upgrades which are required to incorporate the proposed facilities have been identified to the extent permitted by a system impact assessment under the current IMO Connection Assessment and Approval process. Additional facility studies may be necessary to confirm constructability and the time required for construction. Further studies at more advanced stages of the project development may identify additional facilities that need to be provided or that require upgrading.

SYSTEM IMPACT ASSESSMENT REPORT

For

QFW TRANSMISSION REINFORCEMENT

This assessment has been conducted to examine the proposed enhancement of the transfer capability of the Queenston Flow West (QFW) interface, to determine the effect that the power flow increase may have on other transmission interfaces and to identify the impact that the proposed new facilities may have on system reliability.

PROJECT DESCRIPTION

The QFW transmission interface, between the Niagara and Southwest zones, has been limiting under hot, windless conditions during summer months. Based on the existing thermal capability of QFW, adding generation in the Niagara zone does not increase generation availability, as the import utilization from New York is correspondingly reduced.

As shown in Figure 1, Hydro One Networks Inc. (Hydro One) is proposing to install new transmission facilities to augment the five existing 230 kV circuits that, together, form the QFW Interface.

The facilities that are planned involve rebuilding the idle A8 and A11 115 kV double circuit line (65 km) between Allanburg Transformer Station (TS) and Caledonia Junction as a double 230 kV double circuit line, and building a new 230 kV double circuit line (11 km) between Caledonia Junction and Middleport TS. These new Middleport x Allanburg 230 kV circuits would tap into the two existing 230 kV Beck x Allanburg circuits Q26A and Q32A at Allanburg TS to form a three ended connection between Middleport, Allanburg and Beck.

The existing summer capability of 230 kV circuits Q26A and Q32A will be increased to provide 1,450 A continuous and 1,900 A 15-Minute Limited Time Rating (LTR). The new Middleport x Allanburg 230 kV circuits will also have a summer capability of 1,450 A continuous and 1,900 A 15-Minute LTR.

The following operating nomenclature is proposed by Hydro One:

- Q32AM for the new three ended circuit formed by tapping the existing Q32A circuit, and
- Q26AM for the new three-ended circuit formed by tapping the existing Q26A circuit.

In addition, connection facilities at Middleport TS will be required for circuits Q26AM and Q32AM. Hydro One proposes to terminate circuit Q32AM into the existing vacant line position in the 230 kV East yard between breakers KL4 and L4L34, and circuit Q26AM into a new diameter equipped with two new breakers. Protection work associated with these line connections will include complete A and B group protections with remote trip facilities.

Existing relaying and communications facilities at Beck and Allanburg will be revised as required to accommodate the new connections into Middleport.

The idle 115 kV circuit A11 currently provides emergency back-up supply for Dunnville TS, which is normally supplied by a single 115 kV circuit Q2AH. Once circuit A11 is rebuilt for 230 kV operation, Hydro One will provide a new line switching arrangement to allow the 115 kV operation of a section of the new 230 kV circuit Q32AM. This provision will serve as the new emergency back-up supply to Dunnville should circuit Q2AH fail.

The planned in-service date for this project is June 2007.

In addition, Hydro One plans to improve the continuous emergency and 15-Minute ratings of 230 kV circuits Q23BM and Q25BM from Neale Junction to Burlington to avoid foreseeable power transfer limitations. This work is planned to be completed before the in-service date of the QFW reinforcement.

Hydro One expects that these new facilities will increase the transfer capability of the QFW interface by approximately 800 MW. The enhanced QFW interface should permit less constrained operation of the Beck generation facilities within the Niagara zone and improve the utilization of the New York-Niagara import capability.

DESCRIPTION OF EXISTING FACILITIES

Figure 1 shows the transmission facilities in the vicinity of the Queenston Flow West (QFW) interface with particular emphasis on the 230 kV system.

The existing QFW interface consists of the following transmission facilities:

- two 230 kV circuits from Beck to Burlington and Middleport (Q23BM & Q25BM),
- two 230 kV circuits from Beck to Hamilton and Middleport (Q24HM & Q29HM), and
- one 230 kV circuit from Allanburg Junction to Middleport (Q30M).

The QFW interface is limited to approximately 1,750 MW in the summer and to approximately 1,950 MW in the winter for flows to the west. There is no limit specified for flows to the east, as the level of flows expected in that direction will not cause system concerns. This interface is constrained by thermal limitations. It should be noted that in real-time operation, the thermal limits for this interface are determined by ambient conditions including wind speed and temperature and may be higher or lower than those used in this study.

The New York (NY) Niagara interconnection, in the winter, is limited from 1,200 to 1,500 MW for flows into Ontario and from 1,000 to 2,000 MW for flows out of Ontario. In the summer, the limit is 1,000 to 1,300 MW for flows into Ontario and 700 to 1,800 MW for flows out of Ontario. The interconnection is constrained by thermal limitations in the winter and summer.

ASSESSMENT ASSUMPTIONS

The load flow used in this study was based on the IMO summer 2004 peak system conditions base case. Since the Lakeview Thermal Generating Station (TGS) will cease to produce power by the end of April 2005, the system model for this study assumed an equivalent amount of replacement generation in the western part of Greater Toronto Area (GTA).

Studies were performed assuming all existing facilities in-service for conditions of high imports over the Ontario – New York Niagara interconnection.

Under the present system configuration, in order to avoid exceeding the short circuit interrupting capability of the 230 kV Middleport breakers, it is necessary to split the Middleport 230 kV bus. The requirement to split the Middleport 230 kV bus is affected by the number of 230/500 kV Middleport autotransformers and the number of Nanticoke generating units in-service. The Middleport bus can be operated solid when one of the following conditions is met:

- One 500/230 kV Middleport autotransformer is out of service, or
- At least four Nanticoke units (230 kV) are out of service.

Since all the Nanticoke units were in-service in the studies, the Middleport 230 kV bus was modeled split.

In order to monitor the effect of these power transfers on the various transmission paths beyond the QFW interface, two new transmission system interfaces were defined as shown in Figure 1.0. These interfaces are:

- *Flow Into Burlington (FIB)* comprising of two double circuit 230 kV lines Q23BM & Q25BM and M27B & M28B, and three 230 kV circuits Q24HM, Q29HM and M34H.
- *Flow Out of Burlington (FOB)* comprising of two 230 kV double circuit lines T39B & T38B and T37B & T36B.

Tables 1, 2 and 3 list the summer continuous emergency and 15-Minute LTR ratings used in this assessment for the QFW interface with the proposed circuit additions, the FIB interface and the FOB interface, respectively. The circuit ratings presented in Tables 1, 2 and 3 have been calculated under a conservative system voltage assumption of 235 kV.

Table 1 QFW Interface with Proposed Circuit Additions – Summer Ratings

Circuit	*Summer (35 °C, 5 km/h, 75% preload)*	
	Continuous Rating	*15-Minute LTR*
Q24HM	1255 A	1510 A
	511 MVA	615 MVA
Q29HM	1275 A	1535 A
	519 MVA	625 MVA
Q23BM	1228 A	1476 A
	500 MVA	601 MVA
Q25BM	1236 A	1489 A
	503 MVA	606 MVA
Q30M	965 A	1118 A
	393 MVA	455 MVA
Q32AM/Q26AM	1452 A	1904 A
	591 MVA	775 MVA

* MVA Ratings calculated on 235 kV

Table 2 FIB Interface – Summer Ratings

Circuit	*Summer (35 °C,5 km/h, 75% preload)*	
	Continuous Rating	*15-Minute LTR*
Q23BM/Q25BM	1452 A	1884 A
	591 MVA	767 MVA
M27B/M28B	1383 A	1612 A
	563 MVA	656 MVA
Q24HM/Q29HM	1580 A	1889 A
	643 MVA	769 MVA
M34H	1305 A	1567 A
	531 MVA	638 MVA

* MVA Ratings calculated on 235 kV

Table 2 reflects Hydro One's plan to improve the continuous emergency and 15-Minute ratings of 230 kV circuits Q23BM and Q25BM from Neale Junction to Burlington by increasing the conductor clearance and allowing continuous emergency operation at 127ºC. This work is expected to be completed by May 2006 or earlier, well before the planned in-service date of QFW transmission reinforcement project.

Table 3 FOB Interface – Summer Ratings

Circuit	*Summer (35 °C, 5 km/h, 75% preload)*	
	Continuous Rating	*15-Minute LTR*
T36B/T37B T38B/T39B	1423 A	2174 A
	579 MVA	885 MVA

* MVA Ratings calculated on 235 kV

EFFECT ON TRANSMISSION THERMAL LOADING

The Queenston Flow West (QFW) interface is in series with the Ontario – New York (NY) Niagara interconnection. All flows entering Ontario on the NY Niagara interconnection will also appear on the QFW interface. Historically, the power flow on the QFW interface has reached its limit often before exhausting the NY Niagara interconnection import transfer capability. As a result, the capability of the NY Niagara interconnection is not always fully utilized.

To avoid the existing QFW limitations constraining NY Niagara interconnection imports under hot, windless conditions, the QFW power transfer capability would need to be greater than 2,300 MW (1,400+1,200-300) based on the following assumptions:

- NY Niagara imports of approximately 1, 400 MW (limit),
- Beck generation of about 1,200 MW, and
- Allanburg 230/115 kV autotransformer loadings of approximately 300 MW, corresponding to off-peak conditions.

Using linear analysis, the power transfer capability of the QFW interface with the proposed circuit additions was assessed by examining various contingencies. The study was performed by displacing generation east of Toronto with generation from New York. Table 5 summarizes the results for the most limiting contingencies.

Table 4 QFW Power Transfer Capability

Monitored Circuit	*Base Flow (MW)*	*Flow on Monitored Circuit (MW) ** denotes limiting circuit*			*Continuous/ 15-Minute Ratings (MW)*
		Q25BM & Q29HM Outage	*Q23BM & Q24HM Outage*	*Q23BM & Q25BM Outage*	
With eight units I/S at Nanticoke					
Q24HM	200.2	615**	0	605	511/615
Q29HM	205.1	0	625**	625**	519/625
Q23BM	160.8	518	0	0	500/601
Q25BM	161.8	0	503	0	503/606
Q30M	80.0	397	395	422	393/455
Q32AM	99.5	444	443	472	591/775
Q26AM	74.0	394	364	397	591/775
Interface Transfer Capability (MW)		***2534***	2588	2745	

The results of the study show that the critical contingency is the loss of the 230 kV double circuit line Q25BM and Q29HM due to the limitation imposed by the 615 MVA, 15-Minute LTR of circuit Q24HM at the Beck end. In order to respect the post-contingency limit of circuit Q24HM, the pre-contingency power flow of the QFW interface must be limited to about 2,534 MW with all elements in-service under summer conditions. The QFW power transfer capability of 2,534 MW is greater than the calculated maximum possible interface flow of 2,300 MW and would remove the existing QFW limitations.

In the past, under summer peak conditions, the FIB interface has constrained power flows on the QFW interface. Therefore, the study results were also examined to determine if FIB and FOB interfaces would constrain power flows on the QFW interface, thus, preventing full utilization of its enhanced power transfer capability.

The most critical contingency constraining the QFW interface due a limitation imposed by the FIB interface is the loss of the 230 kV double circuit line Q23BM and Q24HM. In particular, the limitation of the FIB interface occurs due to the 767 MVA, 15-Minute LTR of circuit Q25BM at the Burlington end. However, as the shown in Table 5, for the loss of double circuit line Q23BM and Q24HM, circuit Q29HM will be more limiting than circuit Q25BM and as such, the power flow on Q25BM will never be greater than 503 MW. Therefore, the limitation imposed on the QFW power transfer capability by circuit Q25BM for this contingency is not likely to occur. The study results also showed that other contingencies that impose a limitation on the QFW power flow due to the FIB interface are not as stringent as the QFW power transfer capability.

A similar exercise showed that there are no contingencies that limit the QFW power flow below its power transfer capability due to the FOB interface.

Power transfer limits for the FIB and FOB interfaces have not been defined for the existing power system because the operating conditions generally experienced until now did not result in any limitations on the interfaces. With the proposed reinforcement of the QFW interface and under different dispatch conditions than those assumed in this study, it is possible that the FIB and FOB power transfer limits could be reached before the power transfer capability of the QFW interface is fully utilized. Therefore, maximum power transfer capabilities for the FIB and FOB interfaces were also established.

As shown in Table 6, for the FIB interface the critical contingency is the loss of the double circuit 230 kV line Q23BM and Q24HM due to limitation imposed by the future 767 MVA, 15-Minute LTR of circuit Q25BM. In order to respect the post-contingency limit of Q25BM the flow over the FIB interface must be limited to about 2,885 MW with all elements in-service under summer conditions.

Table 5 FIB Power Transfer Capability with Proposed Circuits Additions to QFW

Monitored Circuit	*Base Flow (MW)*	*Flow on Monitored Circuit (MW) ** denotes limiting circuit*			*Continuous/ 15-Minute Ratings (MW)*
		Q23BM & Q24HM Outage	*M585M & V586M Outage*	*Q25BM & Q29HM Outage*	
With eight units I/S at Nanticoke					
Q23BM	373.0	0	763	767**	591/767
Q25BM	375.0	767**	767**	0	591/767
M27B	256.0	406	515	440	563/656
M28B	255.6	406	515	439	563/656
Q24HM	335.1	0	650	765	643/769
Q29HM	306.0	651	603	0	643/769
M34H	210.7	329	328	340	531/638
Interface Transfer Capability (MW)		***2885***	2989	3027	

As shown in Table 7, for the FOB interface the critical contingency is the loss double circuit 500 kV line M585M and V586M due to limitation imposed by the 885 MVA, 15-Minute LTR of circuit T37B or T36B. In order to respect the post-contingency limit of T37B or T36B the flow over the FOB interface must be limited to about 2,015 MW with all elements in-service under summer conditions.

Table 6 FOB Power Transfer Capability with Proposed Circuits Additions to QFW

Monitored Circuit	*Base Flow (MW)*	*Flow on Monitored Circuit (MW) ** denotes limiting circuit*			*Continuous/ 15-Minute Ratings (MW)*
		M585M & V586M Outage	*No Outage*	*T36B & T37B Outage*	
With eight units I/S at Nanticoke					
T36B	139.8	885	579	0	579/885
T37B	140.0	885**	579**	0	579/885
T38B	115.3	859	554	885**	579/885
T39B	115.3	859	554	885**	579/885
Interface Transfer Capability (MW)		***2015***	2266	2279	

EFFECT ON TRANSMISSION VOLTAGES

Studies were performed to determine the effect of connecting the two new 230 kV circuits from Allanburg to Middleport on the steady state voltage levels in the electrical proximity of these circuits. No voltages concerns are expected to occur with the addition of the new circuits.

EFFECT ON POWER TRANSFERS – TRANSMISSION DISTRIBUTION FACTORS

Linear analysis was performed to determine the distribution of power over the QFW, FIB and FOB interfaces with the enhanced QFW transfer capability when generation in the Toronto zone is displaced with generation from Bruce, Lambton, Beck and Nanticoke. Table 2 below summarizes the system Transmission Distribution Factors for the generation shifts studied.

Table 7 Transmission Distribution Factors

	Monitored Lines		Base Case Flow (MW)	Generation raised at…			
				Bruce	Lambton	Beck	Nanticoke
1	INTERFACE	QFW	981.4	0.025	0.19	0.896	0
2	INTERFACE	FIB	2111.4	0.18	0.321	0.481	0.347
3	INTERFACE	FOB	510.4	0.18	0.321	0.481	0.347

As expected, power flows on the interfaces increase significantly when Beck generation in the Niagara zone displaces generation in the Toronto zone. Ninety percent of the generation will appear on the QFW interface, while forty-eight percent of the generation will appear on both the FIB and FOB interfaces. This scenario represents the most stressful case in terms of the power flows on and beyond the QFW interface, and is very similar to the study conditions used in the previous section.

ALLANBURG LOCAL AREA SUPPLY

The Allanburg local area is supplied by 230/115 kV autotransformers T1, T2, T3 and T4 at Allanburg TS. Presently, autotransformers T1, T2 and T4 are supplied by 230 kV feeder circuits Q26A, Q28A and Q32A, respectively. Autotransformer T3 is tapped off 230 kV circuit Q30M. Under summer peak conditions, the total loading on these autotransformers is approximately 600 MW.

The Allanburg autotransformers are rated as follows:
T1 – 10-Day LTR 227 MVA; 15-Minute LTR 294 MVA
T2 – 10-Day LTR 414 MVA; 15-Minute LTR 469 MVA
T3 – 10-Day LTR 315 MVA; 15-Minute LTR 406 MVA**
T4 – 10-Day LTR 414 MVA; 15-Minute LTR 476 MVA***
** T3 loading series limited to approximately to 323 MVA at 115 kV due to cable limitations on low voltage side.
*** T4 loading series limited to approximately to 426 MVA at 115 kV due to cable limitations on low voltage side.

As shown in Figure 1, the proposed 230 kV double circuit line connection to the existing 230 kV circuits Q26A and Q32A at Allanburg will result in the Allanburg autotransformers T1 and T4 being tapped off the new circuits Q26AM and Q32AM. This will increase the exposure for a simultaneous loss of Allanburg autotransformers T1 and T4 due to a single tower contingency. If autotransformer T2 is out of service and the simultaneous loss of autotranformers T1 and T4 occurs, the Allanburg local area would only be supplied by autotransformer T3. Under system peak conditions, the resulting load level on T3 would exceed its thermal capability without appropriate control actions.

The IMO recommends that Hydro One install isolating devices just west of Allanburg on the proposed Q26AM and Q32AM circuits for emergency purposes, to allow the Allanburg autotransformers T1 and T4 to be supplied radially from Beck in case of a permanent double circuit line outage between Middleport and Allanburg.

However, it should be noted that the installation of isolating devices does not cover all risks associated with the Allanburg local area supply. Based on the existing supply arrangement for this area, the simultaneous loss of Allanburg autotransformers T3 and T4 could occur due to a single tower contingency on the Q30M and Q32A double circuit line between Allanburg and Beck. Similarly, the loss of Allanburg T1 and T2 could occur due to a single tower contingency on the Q26A and Q28A double circuit line between Allanburg and Beck. In either case, the post-contingency supply of the Allanburg local area would only be supplied provided by two autotransformers. In the former case, if autotransformer T2 was out of service prior the tower contingency, the Allanburg local area supply would only be supplied by T1 – the lowest rated autotransformer at Allanburg.

MIDDLEPORT TS CONNECTION ARRANGEMENT

Figure 2 shows the Hydro One proposed line connections for circuits Q26AM and Q32AM at Middleport TS. Q26AM is to be terminated in the east Middleport 230 kV switchyard and Q26AM is to be terminated in the west Middleport 230 kV switchyard.

Various Q26AM and Q32AM line connection arrangements at Middleport were reviewed with the intent of verifying whether the proposed line connections optimize the power transfer capability of the FIB interface. The studies reveal a relative improvement of approximately 200 MW to the FIB power transfer capability if both circuits were to be terminated in the east Middleport 230 kV switchyard.

The IMO recommends that Hydro One review the possibility of terminating both circuits to the east 230 kV switchyard, but not at adjacent line positions. Terminating the circuits at adjacent line positions would leave the Allanburg local area supply vulnerable to the loss of two autotransformers due a Middleport breaker fail operation of the common breaker. Likewise, the termination of a new circuit adjacent to the existing Q30M line position is not recommended.

DUNNVILLE TS BACK-UP SUPPLY

As noted in the project description, the new 230 kV circuit Q32AM will serve as an emergency back-up supply to Dunnville TS. When employed, the new line switching arrangement should allow for the operation of the Allanburg T4 autotransformer radially from Beck.

The City of Thorold has a 230 kV load that is normally connected to the existing Q32A circuit (Q32AM in the future). The characteristics of the industrial process associated with this existing load may force long waits before the Dunnville back-up switching is permitted or before the Allanburg x Middleport line isolation can be permitted. Therefore, Hydro One has a plan to re-connect this 230 kV load from Q32A to Q28A by May 2005. Circuit Q26A (Q26AM in the future) will continue to serve as the emergency back-up supply to this load.

The proposed re-connection of this 230 kV load to circuit Q28A would facilitate the back-up switching for Dunnville TS should the need arise. The IMO has no concerns with this plan.

EFFECT ON SHORT CIRCUIT LEVELS

The impact of the proposed two new 230 kV circuits between Allanburg and Middleport on the system short circuit levels was assessed for a system with:

- all existing transmission facilities in-service including the Allanburg TS series reactors,
- Allanburg T3 and T4 transformers modeled with tertiary windings open,
- Lakeview TGS out of service,
- Both Sithe generation projects and Portlands generation project in-service,
- Thorold Northland Power generation project in-service (300 MW)
- Lake Erie AIM POWERGEN generation project (100 MW), and
- All existing generation in-service.

Hydro One has performed fault level studies to determine the effect of connecting the two new 230 kV circuits on the short circuit levels experienced at transformer stations that are in the electrical proximity of these circuits The study assumed that Middleport 230 kV switchyard is operated split, and the two new circuits are connected to the west and east Middleport switchyards respectively.

The table below summarizes the results of the short circuit analysis for maximum system representation and voltage conditions with and without the new 230 kV Q26AM and Q32AM circuits in-service.

Table 8 Faults Levels

Station		Symmetrical (kA)		Asymmetrical (kA)		Breaker Ratings	
		3-phase	L-G	3-phase	L-G	Symmetrical	Asymmetrical
Middleport 230 kV (East)	**Baseline**	42.	40.4	50.9	48.1	**63 kA (Certain bus sections rated at 54 kA)**	
	2-230 kV Circuits	44.3	42.3	53	49.6		
		2.3 kA	**1.9 kA**	**2.1 kA**	**1.5 kA**		
Middleport 230 kV (West)	**Baseline**	39.5	37.3	47.7	43.	**63 kA**	
	2-230 kV Circuits	42	39.3	50.1	44.6		
		2.5 kA	**2 kA**	**2.4 kA**	**1.6 kA**		
Beck GS#2 230 kV	**Baseline**	55.5	59.2	71.5	77.1	**69.3 kA**	**90.1 kA****
	2-230 kV Circuits	58.1	61.3	74.2	79.1		
		2.6 kA	**2.1 kA**	**2.7 kA**	**2 kA**		
Allanburg 115 kV	**Baseline**	33.4	34.3	42.5	39.6	**39.3 kA**	**45.5 kA*****
	2-230 kV Circuits	34.5	35.5	44	41		
		1.1 kA	**1.2 kA**	**1.5 kA**	**1.4 kA**		
Burlington 230 kV	**Baseline**	47.5	40.7	53	45.4	**63 kA**	
	2-230 kV Circuits	48.3	41.1	53.9	45.9		
		.8 kA	**0.4 kA**	**0.9 kA**	**0.5 kA**		

** Assumed to be approximately 1.3 p.u. of symmetrical interrupting capability
*** Based upon 10,000 MVA asymmetrical capability at 127 kV

The short circuit study results presented in the table show that the addition of the new circuits will result in an increase in fault levels at the monitored IMO-controlled grid switching stations. The calculations show that the short circuit currents increased by up to 2.6 kA and the symmetrical ratings of the station breakers is not exceeded. It should be noted that the based on the assumed generation conditions , the short circuit currents at Allanburg 115 kV bus and to a lesser extent at Beck GS#2 230 kV bus, appear to be approaching the interrupting capability of the breakers.

Short circuit level studies were not completed to determine the affect of terminating both of the proposed circuits into the east Middleport 230 kV switchyard. If this connection option is be implemented, Hydro One is required to perform fault level studies for this configuration and provide the study results to the IMO. Hydro One has identified a requirement that short circuit levels in the east Middleport 230 kV switchyard must be controlled to below 54 kA symmetrical. Certain bus sections of this yard are only suitable for 54 kA.

CONCLUSIONS

This System Impact Assessment concluded that the proposed project will enhance the power transfer capability of the Queenston Flow West (QFW) interface to approximately 2,534 MW, which is approximately 800 MW more than the existing capability. The enhanced transfer capability with all elements in-service will allow the unconstrained operation of the existing Beck generation facilities within the Niagara zone, improve the utilization of New York-Niagara import capability, and provide limited room for generation expansion within the Niagara zone.

Increasing the transfer capability of the QFW interface will have a considerable impact on the power flows over the 230 kV transmission facilities beyond the QFW interface, particularly, power flows into and out of Burlington TS. However, this assessment concluded that the increased power flows beyond the QFW interface are not expected to prevent the full utilization of the enhanced QFW power transfer capability.

The assessment also established maximum power transfer capabilities for the Flow Into Burlington (FIB) and Flow Out of Burlington (FOB) interfaces of 2,885 MW and 2,015 MW, respectively. The FIB power transfer capability incorporates Hydro One’s plan to improve the thermal ratings of 230 kV circuits Q23BM and Q25BM from Neale Junction to Burlington in 2005.

The short circuit study results show that the addition of the new circuits will result in an increase in fault levels at the monitored IMO-controlled grid switching stations but the symmetrical ratings of the station breakers is not exceeded. However, the short circuit currents at Allanburg 115 kV bus appear to be approaching the interrupting capability of the breakers.

RECOMMENDATIONS

To provide operating flexibility, the IMO recommends that Hydro One install isolating devices just west of Allanburg on the new 230 kV circuits Q26AM and Q32AM. The isolating devices would allow Allanburg autotransformers T1 and T4 to be supplied radially from Beck in case of a permanent double circuit line outage of circuits Q26AM and Q32AM between Middleport and Allanburg.

To increase the FIB power transfer capability beyond the capability identified in this assessment, the IMO recommends that Hydro One review the possibility of terminating Q26AM and Q32AM in the east Middleport 230 kV switchyard, but not at adjacent line positions. Terminating the circuits at adjacent line positions or terminating one circuit adjacent to the existing Q30M line position would leave the Allanburg local area supply vulnerable to the loss of two autotransformers due a Middleport breaker fail operation of the common breaker.

To provide operating flexibility, the new line switching arrangement for employing the Q32AM emergency supply to Dunnville TS should allow for the operation of the Allanburg T4 autotransformer radially from Beck.

SUMMARY OF IMO REQUIREMENTS

To incorporate the proposed project to the IMO-controlled grid, Hydro One is required to:

1. Install on-line monitoring facilities as specified in the Market Rules, and
2. Design and build protection systems according to the Transmission System Code requirements and NPCC Bulk Power System Protection Criteria,
3. Install auto-reclosure facilities (U/V+T and synchrocheck) for the Middleport and Beck breakers, and
4. Perform additional fault level studies and provide the study results to the IMO if the new Q26AM and Q32AM circuits are both terminated into the east Middleport 230 kV switchyard.

NOTIFICATION OF APPROVAL

It is recommended that a *Notification of Approval for Connection* be issued for this project subject to implementation of the requirements described above and those of the IMO facility registration process..

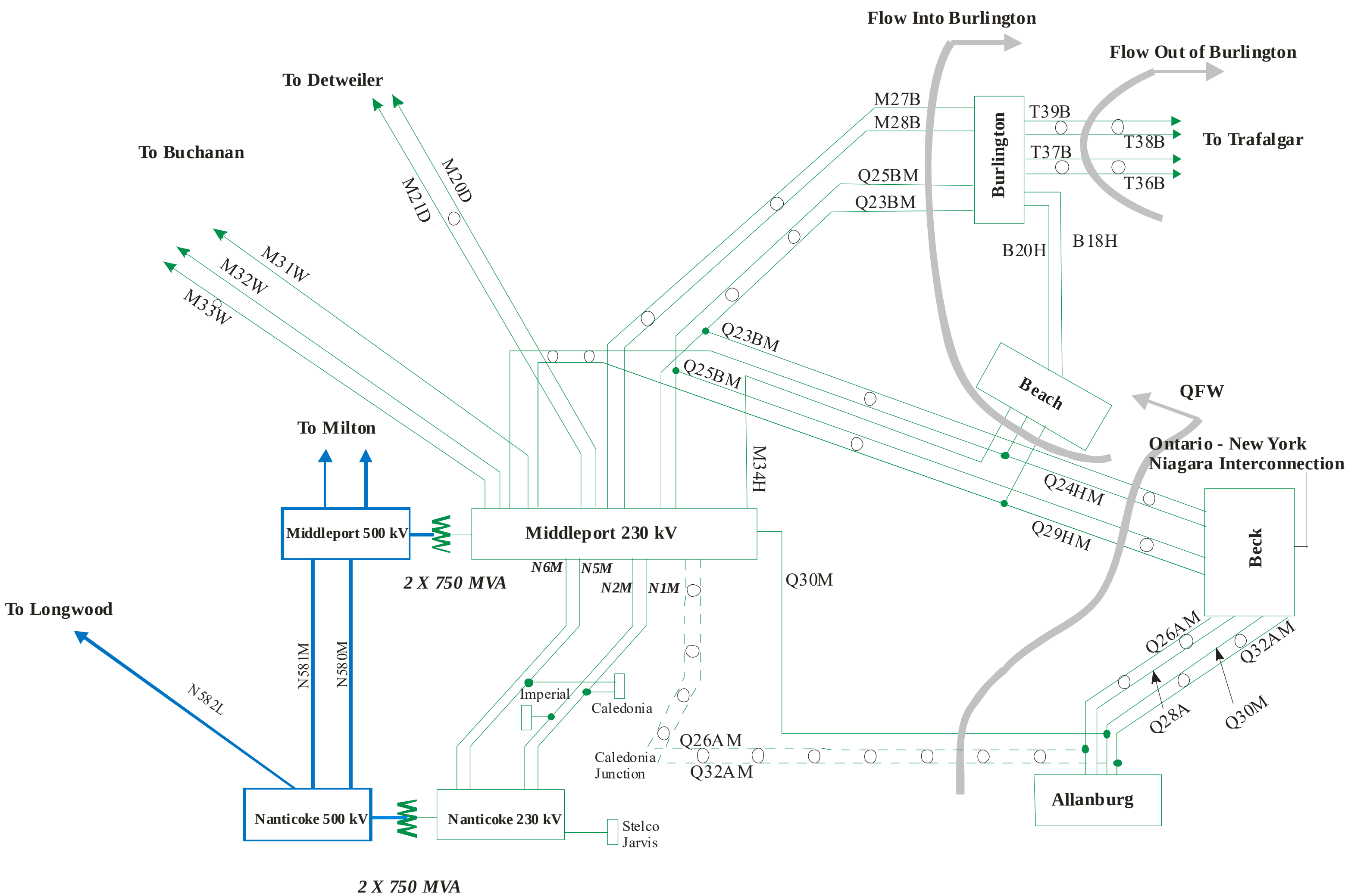
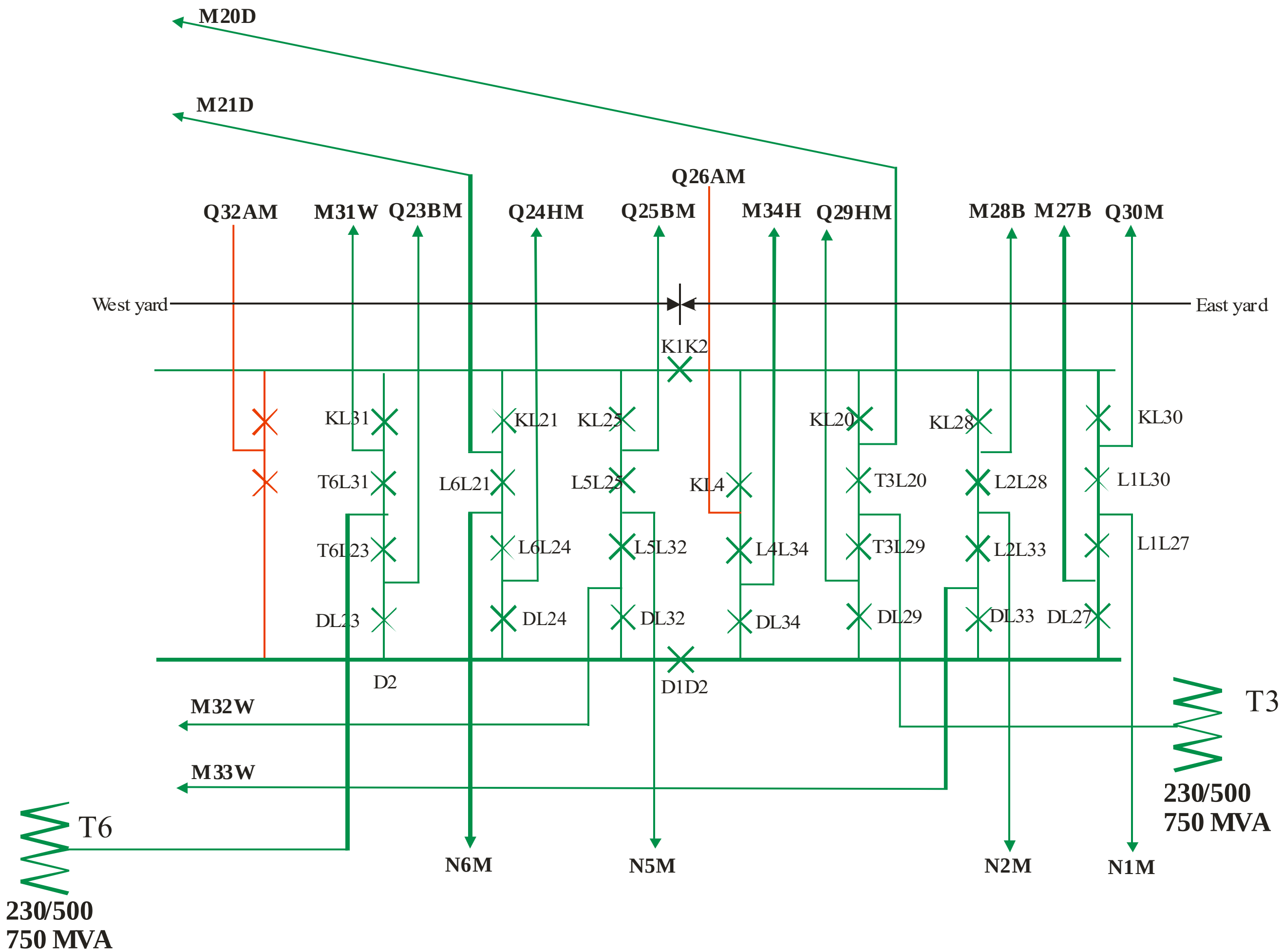


Figure 1 - QFW Transmission Reinforcement Plan & Existing Transmission Facilities



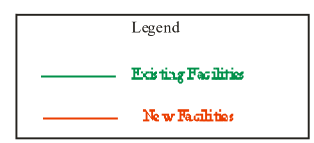


Figure 2. Proposed Middleport TS Configuration New Circuits

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Joanne Richardson
Director – Major Projects and Partnerships
Regulatory Affairs

BY COURIER

April 4, 2018

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
Suite 2700, 2300 Yonge Street
P.O. Box 2319
Toronto, ON M4P 1E4

Dear Ms. Walli:

EB-2004-0476 - Hydro One Networks Inc.'s Niagara Reinforcement Project

Hydro One Networks received section 92 approval to construct the Niagara Reinforcement Project ("NRP") on July 8, 2005. Due to a land dispute in Caledonia, Ontario, the project was unable to be completed and placed in-service. Per Appendix A Section 1.3, in the Conditions of Approval, Hydro One is advising the Board of a material change to the project and seeking approval to complete construction as described in this letter.

PROJECT DESCRIPTION AND BACKGROUND

In October 2004, Hydro One sought approval to construct transmission facilities in the Niagara Region (please see Figure 1 for a map of the project area) to alleviate transmission constraints at the Queenston Flow West transmission interface. The Project, with an estimated cost to complete of $116 million, included:

- construction of a new 76 km double circuit 230 kV transmission line between Allanburg Transformer Station ("TS") and Middleport TS;
- upgrades to Middleport TS; and
- a provision that would enable a section of one new 230 kV line, from Caledonia TS to St. Ann's Junction) to be operated at 115 kV as emergency back-up supply for Dunnville TS.

The planned in-service date was the summer of 2007.

In the summer of 2006, when the project was near completion, an unforeseen land claim dispute, unrelated to the project, between a developer and the First Nations communities in the Caledonia area put the project on hold. This disruption did not allow a section of the line near Caledonia to be completed, and therefore the line could not be put in-service.

In EB-2006-0501, the OEB provided Hydro One with relief from the carrying charges that it would incur on the funds used to finance the NRP, allowing Hydro One to recover AFUDC, based on the project's $98 million cost incurred.

CURRENT STATUS

The Niagara Interface and Queenston Flow West interface are critical corridors for moving supply into the province, as it facilitates the importing and exporting of power between New York state and Ontario. The existing Niagara transmission capability can limit imports via the New York interties and at times can constrain the hydroelectric generation in Niagara. Limitations on the 230kV Niagara transmission capability restrict any significant new renewable or clean energy development in the Niagara area. In the last Large Renewable Program (LRP) procurement, the Niagara area was a restricted zone for prospective projects. NRP increases the number of 230kV circuits connecting the Niagara area system to the rest of Ontario from five to seven. The IESO's 18-month Outlook *"An Assessment of the Reliability and Operability of the Ontario Electricity System"* released on March 21, 2018 confirms that transmission congestion continues to restrict generation in the Niagara region and that the NRP project once completed, will increase the transfer capability to the rest of the Ontario system by approximately 700 MW.[1]

NRP will allow for more cost effective and timely refurbishment of the very critical Sir Adam Beck II transmission station which connects the Beck generation and the interconnections with New York. Because of the high utilization and criticality of the 230kV Niagara transmission circuits there are significant limitations for outages that results in complex and lengthy refurbishment work at the Beck II station. NRP will significantly alleviate such limitations such as outage durations at Middleport TS[2].

The NRP is also expected to provide additional value to transmission ratepayers by reducing line losses on the QFW interface by between 10,500 MWh and 22,750 MWh on an annual basis.

Since 2006, Hydro One has attempted to reach an agreement with the affected First Nations. In late 2016 and throughout 2017, substantial progress has been made such that Hydro One and the Six Nations Elected Council believe an agreement has been reached which will allow completion of the NRP.

In order to complete construction of the NRP the following work is required (please see Figure 2 below):

[1] IESO's 18-month Outlook *"An Assessment of the Reliability and Operability of the Ontario Electricity System"* , page 29

[2] In the 2003 Blackout, a key breakup of the Ontario system occurred over the Niagara 230kV circuits because the Niagara generation complex is more strongly coupled to New York than Ontario. This was a contributing factor for upper state NY to stay intact while Ontario did not. During major system disturbances and islanding conditions, hydroelectric generation is the most robust source of generation to maintain system stability.

- String 8.5km of 230kV transmission line, from tower #248 east of Caledonia TS near Grand River to tower #285 northwest of Caledonia TS, about 10% of the whole project
- Install 21 structures from Caledonia TS towers 266 A/B to tower #282 required due to vandalism over the years
- Erect two 3-pole structures and an air break switch and connect it to existing 115kV line at Caledonia Junction (emergency supply to Dunville TS)
- Install additional protection facilities at Middleport TS, Allanburg TS and Sir Adam Beck SS #2
- Repair and reinforce access roads
- Increase height of outstanding towers due to change in clearance standards
- Remove and restring conductors and shield wires in the incomplete section from tower #248 to #253 due to aging (creep)
- Vegetation management in the completed portions of the line

To facilitate the remaining work, Hydro One will utilize A6N, a partnership between Aecon Utilities Inc. and The Six Nations of the Grand River, for their construction services for completion of the Niagara Reinforcement Project.

The 2005 section 92 approval was for a total project cost of $116 million to be in-service in 2007. The total project cost to complete this work is now estimated to be $129.2 million, with an in-service date in May 2019. Project costs are estimated to be approximately $13 million, or 11%, over the previously approved amount.

After a detailed re-estimate, there is more work required to place the asset into service than initially described in EB-2008-0272 filed September 30/08. Due to vandalism over the last 12 years, some new tower and line work will be needed, requiring stringing of 8.5 km of transmission line to connect to the conductor termination points. Some material necessary to complete the project (lattice structures, insulators) needs to be repurchased. Also, protection changes are necessary to the terminal stations as a result of Thorold GS now connected to one of the circuits (Q26M) in 2010.

Hydro One believes that the incremental cost to complete the project is a prudent expenditure and should be approved. The NRP will deliver benefits to Ontario's ratepayers by providing increased supply capacity, reducing line losses and facilitating outage reliability in the Niagara region.

REVENUE REQUIREMENT RECOVERY

The costs associated with the NRP are currently in Hydro One Transmission's construction work-in-progress account. Hydro One anticipates that a partnership agreement will be reached between The Six Nations of the Grand River, The Mississaugas of New Credit and Hydro One, leading to the formation of a new transmission company and the ultimate transfer of the NRP asset out of Hydro One into the new company. As a result, Hydro One Transmission will not include the in-service addition of the NRP in its 2018 rate base, as part of its upcoming 2019-2022 transmission rate filing. If the partnership is formed, a separate application will be made seeking revenue recovery on the in-serviced rate base. If a partnership is not formed, Hydro One Transmission will apply to the Board for a deferral account to record related expenses and foregone revenue, to be disposed of in a future hearing.

An electronic copy of this has been filed through the Ontario Energy Board's Regulatory Electronic Submission System (RESS).

Should you have any questions on this application, please contact myself at (416) 345-5393 or via email at Joanne.Richardson@HydroOne.com.

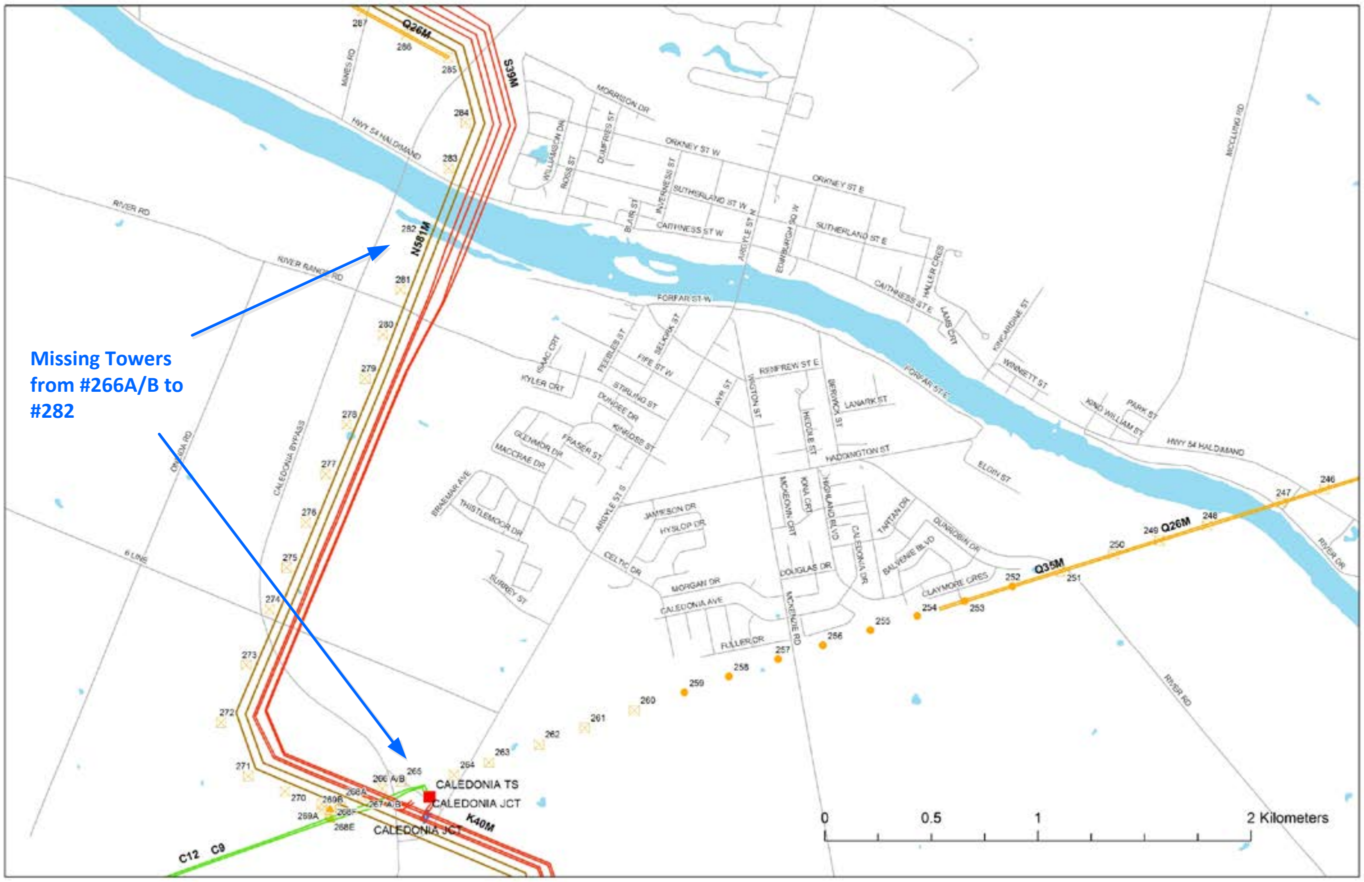
Sincerely,

ORIGINAL SIGNED BY JOANNE RICHARDSON

Joanne Richardson

Figure 1: Overall Project Location

Figure 2: Detailed View of the Line Section to be completed



OEB INTERROGATORY #3

Reference:
(1) Exhibit A, Tab 2, Schedule 3, page 1
(2) Exhibit B, Tab 2, Schedule 1, page 4

Interrogatory:
Preamble:
At the above noted first reference, NRLP states:

> *As part of this application, NRLP is filing, on behalf of HONI, an update on the final Niagara Reinforcement project costs. This request arises from the OEB decision in the asset transfer application that determined that the value of the Niagara Reinforcement assets would be determined in a future rates proceeding.*

At the above noted second reference, NRLP states the following in respect of final Niagara Reinforcement project costs:

> *A primary reason for the increase since the 2005 estimate is simple inflation. Costs, including the price of the various inputs to the project such as labour and materials, would normally and reasonably be expected to increase over the 14 years between the original estimate and the final construction cost. Hydro One was able to reuse certain assets and negotiated favourable terms with its contractor to minimize cost increases due to inflation.*

Questions:
a) As stated by NRLP at Exhibit B, Tab 2, Schedule 1, page 3, the Niagara Reinforcement project was near completion in the summer of 2006. Please provide the following details related to the status of the project:

i. Amount of the forecasted construction budget of $116.0 million that had been spent before the land claim dispute referenced at Exhibit B, Tab 2, Schedule 1, page 3 required NRLP to suspend construction in 2006.

ii. The amount of additional funds Hydro One/NRLP incurred to remediate the completed assets and to complete the remaining elements of the project during 2018-2019 period.

<u>Response:</u>

i. $98.2M was spent at the time construction was suspended, due to the land dispute, in 2006. Please refer to Exhibit I, Tab 1, Schedule 2, Attachment 7.

ii. An additional $37.0M was required to complete the remainder of the project.

OEB INTERROGATORY #4

Reference:

(1) Exhibit B, Tab 2, Schedule 1, page 4

Interrogatory:

Questions:

a) At the above noted reference, NRLP lists a number of “project challenges”. These challenges represent investments NRLP was required to make in order to complete the project following the 2006 suspension, putting upward pressures on project costs. For each of the listed project challenges, please discuss/provide the following:

i. The extent to which the challenge was considered during NRLP’s July 8, 2005 leave to construct approval proceeding. If the challenge was not reflected in NRLP’s original project plan, please detail why the investment became necessary post-2006 suspension. As an example, one of the project challenges is described as “stringing of 8.5km of transmission line was required to connect to the conductor termination points.” If this project challenge was not considered during the previous leave to construct proceeding, please discuss why it became necessary post-2006 suspension.

ii. The actual costs incurred by NRLP to address each project challenge. If the challenge was considered during NRLP’s July 8, 2005 leave to construct proceeding, please provide a comparison of the challenge’s forecast versus actual costs (and provide rationale for any variances).

b) NRLP indicates that it was required to repurchase certain materials to complete the project, including lattice structures and insulators. For each repurchased material, please provide the following:

i. A description for why a repurchase was necessary as well as what happened to the originally purchased materials.

ii. The original purchase price of these materials as well as the price of their replacements.

Response:

a)

i. At the time of the 2006 project suspension, 7.3km of the line remained to be completed. When the project was re-started, an additional 1.2km of line that was previously strung in 2006, was required to be re-strung. The 1.2km of line re-stringing was necessary as the conductor tensioning work had not been completed at the time of the work stoppage and the conductor was damaged due to elongation or conductor creep.

ii. The costs associated with the specific challenges is as follows:

No.	Work Description	Costs ($M)
1	Tower and line rework around Caledonia - 13 structures had to be re-built due to vandalism.	10.2
2	Restringing an extra 1.2 km of transmission line due to damage due to conductor creep (8.5km of double circuit line versus original unfinished length of 7.3km)	1.0
3	Material required to be repurchased	1.7
4	Protection changes due to Generator connection	1.5

b)

i. Some of the material, this included tower steel and insulators had to be repurchased due to vandalism pertaining from the land dispute. When Hydro One returned to the project site after a 12 years absence, it was found that some material was missing and other had to be scrapped due to the level of damage from the vandalism.

ii. The original purchase price for this material, which includes replacement structures and insulators, was estimated at $1.3M in 2006 and the replacement cost $1.7M at project end (2019).

OEB INTERROGATORY #5

Reference:

(1) Exhibit B, Tab 2, Schedule 1, page 6

Interrogatory:

Preamble:

At the above noted reference, NRLP states:

> *As documented in Exhibit C, Tab 1, Schedule 1, the in service additions that NRLP is seeking to include in its rate base through this application are $119.4 million. The remaining $15.8 million of project costs be added [sic] to HONI's Rate Base. This residual amount of assets was not included in the transfer to NRLP and is primarily related to station assets and Optical Ground Wire, which will continue to be owned by HONI.*

Question:

a) OEB staff have identified one or more missing words in the above reference. Please correct the sentence such that NRLP's proposal with respect to how the remaining $15.8 million of project costs will be treated is clear.

Response:

The missing word is *will*.

The extract should read:

> As documented in Exhibit C, Tab 1, Schedule 1, the in service additions that NRLP is seeking to include in its rate base through this application are $119.4 million. The remaining $15.8 million of project costs *will* be added to HONI's Rate Base. This residual amount of assets was not included in the transfer to NRLP and is primarily related to station assets and Optical Ground Wire, which will continue to be owned by HONI.

OEB INTERROGATORY #6

Reference:

(1) Exhibit A, Tab 2, Schedule 2, page 3

Interrogatory:

Preamble:

With respect to benchmarking, NRLP states:

> ***Benchmarking:*** *Operations and management services are provided to NRLP through a service level agreement with Hydro One Networks Inc. These types of activities are subject to review through Hydro One Networks Inc.'s external benchmarking evidence provided in its transmission rate applications.*

Question:

a) Please confirm that NRLP is stating that, as its operations and management are provided by Hydro One Networks' Transmission staff, NRLP's operational costs and operational performance would be the same as for Hydro One Networks' Transmission's operations, if it were benchmarked against a comparator group of electricity transmitters. If not, why not?

Response:

a) NRLP is stating that the operations and management service it requires are provided by Hydro One Networks. For the purposes of benchmarking, any benchmarking data provided by NRLP would be ensconced within the data already provided by Hydro One Networks. This may or may not be exactly comparable to the benchmarking results provided across the entire province that Hydro One Networks serves.

OEB INTERROGATORY #7

Reference:
Exhibit A, Tab 2, Schedule 2, page 4

Interrogatory:
Preamble:
NRLP states:

> ***Protecting Customers:*** *Exhibit A, Tab 4, Schedule 1 outlines NRLP's proposed Earnings Sharing Mechanism (ESM) which shares the benefit of productivity improvements with customers during the term and provides rate payers with protection from utility earnings that may exceed proposed levels.*

Question:
a) The ESM will provide some level of protection against excessive over-earnings (i.e., above the 100 basis point threshold), and productivity improvements may be an underlying factor for the occurrence of the over-earnings. However, the ESM would not apply unless earnings exceed the allowed return by 100 basis points. With the OEB's established return on equity (ROE) of 8.52%, achieved earnings on a regulated basis would have to exceed 9.52% for the ESM to be triggered during the plan term. With NRLP's proposed X-factor (of a base X and stretch) of 0%, it may be the case that NRLP is proposing that no realized productivity improvements are shared with ratepayers during the term of the plan.

   In line with the proposed revenue cap adjustment formula, please explain how the ESM "shares the benefit of productivity improvements with customers during the term [of the plan]".

Response:
a) The majority of the OM&A expenses expected by NRLP will be charges emanating from its Management Services contract with Hydro One Networks. For clarity, any meaningful productivity benefits are related to productivity and other cost savings obtainable from HONI through that contract. If the savings are sufficiently large to

create an incremental return of more than 100 bps, those amounts will be shared with customers during the term of the plan.

OEB INTERROGATORY #8

<u>Reference:</u>
(1) Exhibit A, Tab 3, Schedule 1, pages 3-18

<u>Interrogatory:</u>
Questions:
At the above reference, NRLP provides an overview of its proposed Revenue Cap Index mechanism.

a) NRLP's proposal for the revenue cap would apply the I – 0% adjustment to the whole revenue cap, even though it is only actually OM&A expenses, mostly incurred per the service agreement with Hydro One Networks, which are subject to inflation during the period. Further, since, with no capital expenditures, the rate base actually decreases each year, and the capital-related revenue requirement would also decrease, the actual increase on the capital-related revenue requirement, relative to what it would be under cost of service, is greater than inflation. Please provide NRLP's views on why its revenue cap proposal is reasonable in light of its circumstances of no projected capex during the five year period and given that OM&A is a smaller proportion of its overall revenue requirement.

b) Please explain whether, given a declining rate base, no projected capital expenditures, and operating expenses being a small percentage of the total revenue requirement, a rate freeze for the plan period of 2020-2024 would be sufficient to allow NRLP to recover its allowed costs, including having an opportunity to earn its allowed return on capital, and to recover costs from Hydro One for operating services under the service agreement with NRLP.

<u>Response:</u>
Please see Exhibit I, Tab 1, Staff IR # 28.

OEB INTERROGATORY #9

Reference:

(1) Exhibit A, Tab 5, Schedule 1

Interrogatory:

Preamble:

The above noted reference provides a description and chart of NRLP and its structure.

Questions:

a) Figure 1 at Exhibit A, Tab 5, Schedule 1, Page 2 identifies Hydro One B2M LP as an NRLP shareholder. Please confirm Hydro One B2M LP as a shareholder or, if it is not, please provide a corrected version of Figure 1.

b) Please provide an update of NRLP's shareholder structure, if there are any changes since the Application was filed.

Response:

a) Figure 1 referenced above is in error. Hydro One Networks, not B2M LP, is the 54.9% shareholder in NRLP. A new Figure 1 is attached to this IR. NRLP apologizes for the confusion.

b) On September 18, 2019, when the transaction was executed, MCFN chose to defer their full investment in the partnership and purchased a 0.1% of NRLP[1]. Hydro One Networks retained the additional share while providing an option to MCFN to purchase their remaining allotment until the earlier of the date a rate order is issued by the OEB or 6 months from the purchase date. With the issuance of the interim rate order by the Board in December of 2019, MCFN has provided official notice of their intention to exercise their option and purchase the remainder of their final intended interest of 20%. This final purchase is set to close on January 31, 2020. This transaction will cause the corporate structure to conform to Figure 1 as originally contemplated.

[1] See Footnote 6 on Page 8 of Exhibit A, Tab 3, Schedule 1.

NRLP

Financial Ownership Structure

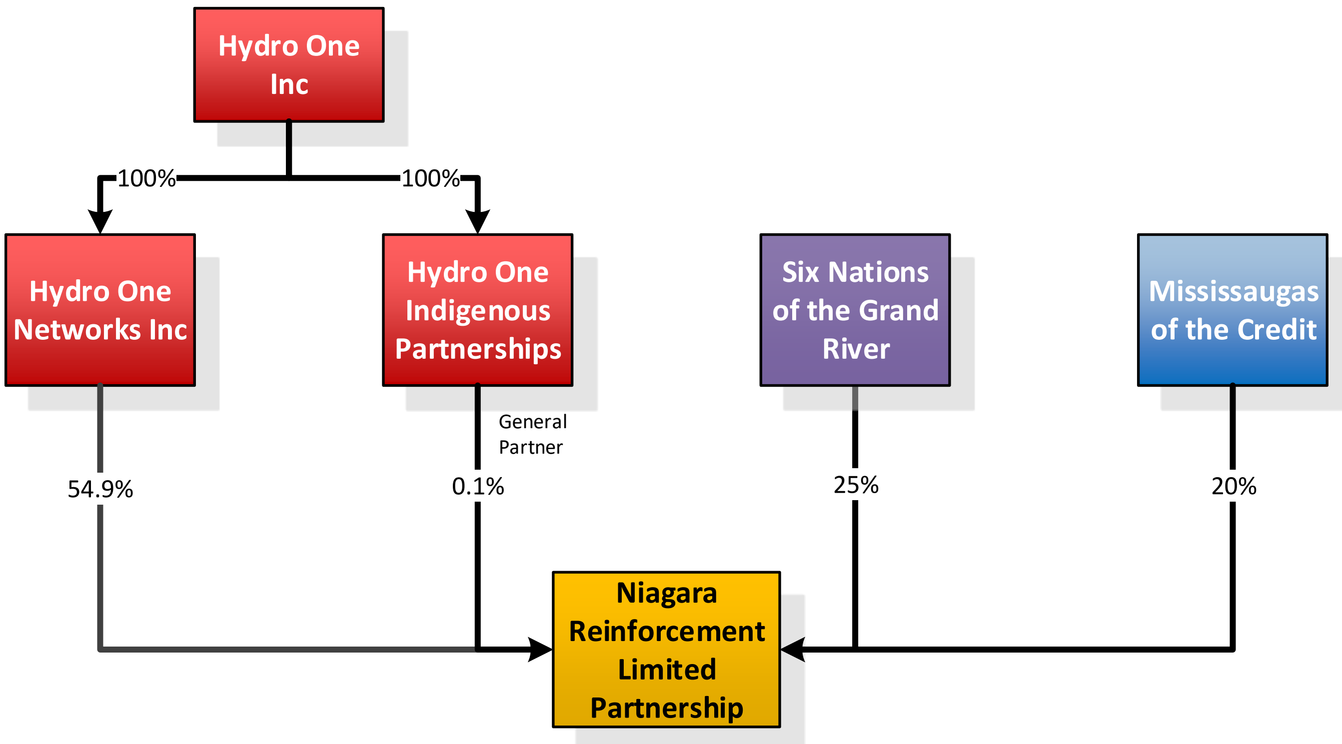


Figure 1 - Organization Chart for the NRLP Shareholder Structure

* As of Jan 31, 2020 – closing date of the second purchase agreement transaction

OEB INTERROGATORY #10

Reference:

(1) Exhibit F, Tab 3, Schedule 1, and Attachment 1

Interrogatory:

Preamble:

NRLP's operations, maintenance, and common administrative and corporate services are provided by Hydro One Networks Inc. through a service level agreement effective for a five-year period beginning September 18, 2019.

Questions:

a) How is NRLP ensuring that the OM&A services provided to it by Hydro One Networks are appropriate and cost effective?

b) Sections 2.3.2.1 and 2.3.2.2 of the Affiliate Relationship Code (ARC) state, respectively:

> *If a utility intends to enter into an Affiliate Contract for the receipt of a service, product, resource, or use of asset that it currently provides to itself, the utility shall first undertake a business case analysis, unless the Affiliate Contract would have an annual value of less than $100,000 or 0.1% of the utility's utility revenue, whichever is greater.*

-and-

> *For the purposes of section 2.3.2.1, the business case analysis shall contain (a) description of relevant utility needs on a per-service basis, (b) identification of the options available internally or externally from an affiliate or third party, (c) economic evaluation of all available options including the utility's current fully-allocated cost (which may include a return on the utility's invested capital equal to the approved weighted average cost of capital), (d) explanation of the selection criteria (including any non-price factors to be taken into account), (e) estimate of any benefits to the utility's Ontario ratepayers from outsourcing,*

> *and (f) justification of why any separate items were bundled together when considered for outsourcing.*

Please provide a copy of the business case analysis developed by NRLP that supports the service level agreement established with Hydro One Networks.

c) Sections 2.3.3.1 and 2.3.3.2 of the ARC state, respectively:

> *Where a reasonably competitive market exists for a service, product, resource or use of asset, a utility shall pay no more than the market price when acquiring that service, product, resource or use of asset from an affiliate.*
>
> *-and-*
>
> *A fair and open competitive bidding process shall be used to establish the market price before a utility enters into or renews an Affiliate Contract under which the utility is acquiring a service, product, resource or use of asset from an affiliate.*

Please describe how the activities undertaken by NRLP when establishing its agreement with Hydro One Networks comply with the above referenced sections of the ARC. If NRLP believes that Sections 2.3.3.1 and 2.3.3.2 of the ARC do not apply to their circumstance, please discuss/provide the assessment undertaken to arrive at this determination.

d) Section 2.3.4.1 of the ARC states:

> *Where it can be established that a reasonably competitive market does not exist for a service, product, resource or use of asset that a utility acquires from an affiliate, the utility shall pay no more than the affiliate's fully-allocated cost to provide that service, product, resource or use of asset. The fully-allocated cost may include a return on the affiliate's invested capital. The return on invested capital shall be no higher than the utility's approved weighted average cost of capital.*

If NRLP believes Section 2.3.4.1 applies to its circumstances, please discuss/provide the assessment undertaken by NRLP to establish that a competitive market for the services contemplated in the service level agreement does not exist.

e) Please detail how the service level agreement integrates Hydro One Networks' productivity improvements into NRLP's maintenance operations, including how efficiencies gained by Hydro One Networks are passed through to NRLP.

Response:

a) NRLP is the unique position of having a 'sister' company (B2M LP) with which it can gauge cost-effectiveness. The service costs provided by HONI compare well in that respect. The Corporate costs are lower mainly due to Real Estate differences in the companies. The vegetation management and operating estimates are substantially lower than B2M, which is a reasonable expectation given the profile of the asset.

b) A formal business case analysis was not performed on the services received by NRLP under the Affiliate Relationship Code from Hydro One Networks. Note that NRLP never provided these services to itself as stated in the quoted passge above. Rather, NRLP was setup from inception to receive these services.

Regardless, many of the services required (e.g. Operating, Treasury, Standards Assurance) are not widely available. However, they are convenient and effectively available from Hydro One Networks. The experience receiving these services from B2M LP has been beneficial and NRLP is enjoying reduced costs on many of the same services so management is very satisfied with the agreement.

c) And

d) The services procured by NRLP from Hydro One are not reasonably available in the market in the manner, type, and quantity that fits with NRLP's requirements. There is no known provider that can unilaterally provide these bundled services in this manner and to enter into a multi-vendor management arrangement would engender significant additional management costs.

All services procured from Hydro One were done so on a fully-allocated cost basis. For a demonstration of the efficacy of the costs, NRLP relies upon the Black and Veatch study of B2M's costs previously completed for HONI and shared with NRLP. While the study is from a past period, the services and terms have not materially changed. The parties considered an update of the study but the cost of this update was deemed unwarranted and imprudent. A copy of the study is included as Attachment 1 to this Interrogatory Response.

e) In its most recent transmission rate application (EB-2019-0082), HONI describes, at length, its numerous productivity initiatives in Section 1.6 of Exhibit B, Tab 1, Section 1 (TSP). A number of the listed initiatives are germane to NRLP, and they ultimately expect to receive benefits from those efforts. Similarly, B2M LP enjoyed productivity benefits in certain areas, the most substantial of which was Operating where the cost to B2M LP was reduced 40% lower than originally forecast. B2M has applied to pass those savings on to ratepayers via its rebasing application and NRLP would seek to do the same, where applicable, in the future.

REVIEW OF ALLOCATION OF COMMON CORPORATE COSTS TO B2M LIMITED PARTNERSHIP

PREPARED FOR

Hydro One Networks Inc.

19 SEPTEMBER 2013

BLACK & VEATCH
Building a world of difference.

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I. Introduction

A. BACKGROUND

Black & Veatch Corporation ("B&V" or "we") is pleased to submit to Hydro One Networks Inc. ("Hydro One") this Report on our Review of Allocation of Common Corporate Costs to B2M Limited Partnership ("B2M Review").

B. HYDRO ONE COMMON CORPORATE COST ALLOCATION METHODOLOGY

In 2004, B&V was engaged by Hydro One to recommend a best practice methodology to distribute its common corporate costs, including costs incurred under its outsourcing contract with Inergi LP, to Hydro One and its subsidiaries. B&V recommended, Hydro One adopted and the Ontario Energy Board ("OEB") accepted a methodology to distribute those costs, as described in our *Report on Common Corporate Costs Methodology Review* dated May 20, 2005 ("2005 Common Costs Report"). The OEB-accepted methodology has been applied to Hydro One's Business Plans, and reviewed by B&V with reports issued, as follows:

B&V REVIEW	BUSINESS PLAN	B&V REPORT
2006 Review	BP 2007-2011	*Report on Implementation of Common Corporate Costs Methodology* dated May 31, 2006
2008 Review	BP 2009-2013	*Report on Implementation of Common Corporate Costs Methodology* dated September 10, 2008
2009 Review	BP 2010-2014	*Report on Shared Services Costs Methodology* dated June 29, 2009
2010 Review	Updated BP 2010-2014	*Report on Shared Services Costs Methodology – 2011* dated February 26, 2010
2011 Review	BP 2012-2016	*Review of Shared Services Cost Allocation – 2011* dated August 22, 2011
2012 Review	BP 2012-2016	*Review of Shared Services Cost Allocation (Transmission) – 2012* dated February 1, 2012

The OEB-accepted methodology to distribute the common corporate costs has been applied by Hydro One to its Business Plan for 2014-19 ("BP 2014-19") data.

C. APPLICATION OF COST ALLOCATION METHOLOGY TO B2MLP

B2M Limited Partnership ("B2MLP") will own the Bruce to Milton Transmission Reinforcement Project ("B2M Line"), and Hydro One will have an ownership interest in, and will provide functions and services to, the B2MLP, as discussed in Section 0. Accordingly, Hydro One has applied the common corporate costs allocation methodology to determine the cost of providing those functions and services to B2MLP. This Report describes the review that B&V performed, at Hydro One's request, of Hydro One's allocation of common corporate costs included in its BP 2014-19 to the B2MLP, and presents B&V's conclusions.

D. SCOPE OF WORK

Consistent with B&V's standard practice for consulting assignments, we relied on the genuineness and completeness of all documents presented to us by Hydro One, and we accepted factual statements made to us by Hydro One (e.g., headcount, budgeted amounts) subject only to their overall reasonableness and any actual contrary knowledge, but without our independent confirmation. All dollar amounts in this Report are stated in Canadian dollars.

II. Organization and Common Corporate Costs

A. HYDRO ONE ORGANIZATION

Hydro One Inc. is wholly owned by the Province of Ontario. It operates through the wholly owned subsidiaries (and the B2MLP) listed in Table 1. The OEB regulates, separately, the business units identified as such in Table 1. Each regulated business is required to account separately for its assets, revenues and costs, for both regulatory and financial accounting purposes.

Table 1 - Business Units

SUBSIDIARY	BUSINESS UNIT	REGULATED	DESCRIPTION
Hydro One Networks Inc.	Transmission	Yes	Owns and operates substantially all of Ontario's electricity transmission system.
	Distribution	Yes	Owns and operates a distribution system which spans approximately 75% of Ontario and serves approximately 1.1 million customers.
Hydro One Brampton Inc	Brampton	Yes	Owns, operates and manages electricity distribution systems and facilities in Brampton, Ontario.
Hydro One Remote Communities Inc	Remotes	Yes	Owns, operates, maintains and constructs generation and distribution assets used to supply of electricity to remote communities in northern Ontario.
Hydro One Telecom Inc.	Telecom	No	Sells high bandwidth telecommunication services to carriers, Internet service providers, and large public and private sector organizations.
Hydro One Inc.		No	Represents activities performed exclusively for the benefit of the shareholder of Hydro One Inc. Most costs it incurs are for the benefit of the other businesses, and are allocated to them.
B2M Limited Partnership	B2M Line	Yes	Will own 100% of a continuous transmission line between the Bruce Nuclear Power Development and Hydro One's Milton Switching station.

B. COMMON SERVICES AND COMMON CORPORATE COSTS

Hydro One provides the functions and services identified in Table 2 to the operating businesses, including the Transmission business.

Table 2 –Functions and Services in Common Corporate Costs

Hydro One Inc. Corporate Office ▪ President/CEO Office ▪ Chair ▪ CFO Office ▪ Treasurer's Office ▪ Board ▪ Corporate Secretariat ▪ General Counsel – VP	**Shared Services** ▪ Treasury ▪ Corporate Controller ▪ Taxation ▪ Outsourcing Services ▪ Real Estate ▪ Regulatory Affairs ▪ Business Planning & Decision Support
Operations ▪ Business Architecture ▪ Power Systems Information Technology (PSIT) ▪ Business Information Technology (BIT) ▪ Security Operations ▪ SVP Planning & Operating ▪ Distribution Development ▪ Transmission Projects Development ▪ Asset Strategy ▪ Network Operations ▪ Transmission Asset Management ▪ Labour Relations ▪ EVP Office – Operations	**Customer Service** ▪ Customer Care Services ▪ Strategy and Conservation ▪ SVP Customer Ops ▪ Distributed Generation ▪ Customer Business Relations ▪ TxDx Settlements ▪ Account Management Director ▪ Advanced Distribution ▪ Value Growth ▪ Pricing ▪ VP Customer Service
Corporate Relations ▪ Corporate Communications and External Relations and Executive Office ▪ First Nations and Métis Relations	**Inergi LP (outsourced services)** ▪ Customer Support Services ▪ Settlement ▪ Finance ▪ Human Resources - Pay Services ▪ Accounts Payable
People and Culture	**Internal Audit**
ETS- Applications Support and Infrastructure Support	**Telecom Services**

Hydro One has distributed among the business units the costs ("Common Corporate Costs"), reflected in its BP 2014-19, of providing those functions and services, using the the OEB-accepted methodology. B&V reviewed Hydro One's allocation and found that it is reasonable, reflects best practices and follows the OEB-approved methodology, as discussed in our *Review of Common Corporate Costs Allocation– 2013* dated September 19, 2013 ("2013 Common Corporate Costs Report").

III. B2M Line and B2M Limited Partnership

A. OVERVIEW

In 2012, the Bruce to Milton Transmission Reinforcement Project ("B2M Line"), a 180-km transmission line delivering electricity from the Bruce Nuclear Power Development to Hydro One's switchyard in Milton, ON, became operational. The two stations operated by Bruce Nuclear Power Development are in Kincardine, ON, on the southeastern shore of Lake Huron; Milton is on the western shore of Lake Ontario, 40 km west of Toronto.

Hydro One was responsible for the construction of the B2M Line. On or about January 1, 2014, Hydro One will transfer ownership of the B2M Line to B2MLP, a partnership in which Hydro One expects to have an ownership interest of 66% (sixty-six percent).

B. HYDRO ONE'S ROLE

Under the terms of an operating agreement, Hydro One will provide both operations and maintenance services for the B2M Line, as well as support functions and services for the B2MLP.

Operations and Maintenance - Hydro One is responsible for operating and maintaining the B2M Line. During the-initial period of operation of the B2M Line (i.e., 2013-2019, corresponding closely to the period of BP 2014-19), the cost of this work is expected to average approximately 0.03% of Hydro One's annual spending for work of this nature on its Transmission business. Hydro One will charge the B2MLP directly for the costs it incurs in operating and maintaining the B2M Line. The amounts charged will reflect fully allocated costs; i.e., labor costs will include salary and wages, benefits and overhead.

Support- In addition, Hydro One is responsible for providing support for the operating and maintenance functions, as well as providing regulatory, legal and tax support for the B2MLP. This support will be provided by the same departments, listed in Table 2, as provide similar functions and services to Hydro One's other business units and are included in Common Corporate Costs.

To reflect the costs of the functions and services to be provided to support the B2MLP, Hydro One has allocated to it a portion of the Common Corporate Costs included in BP 2014-19. The appropriateness of that allocation is the subject of the B2M Review performed by Black & Veatch and discussed in this Report.

IV. Allocation Methodology and Results

A. COSTS TO BE ALLOCATED

The costs of the operation and maintenance of the B2M Line, and of the functions and services to be provided to the B2MLP, are currently included in the rates of Hydro One's Transmission business. Therefore the Common Corporate Costs allocated to the B2MLP are a portion of the total Common Corporate Costs currently distributed to the Transmission business; costs distributed to the Transmission business have been determined by applying Hydro One's Common Corporate Costs Allocation methodology to BP 2014-19 data.

Only certain of the functions and services included in Common Corporate Costs are needed for Hydro One to provide the indicated support for the B2MLP. In addition, the level of effort required to provide this support is expected to vary over the period 2013-2019. The highest levels of effort are expected in the first year due to the newness of the B2MLP entity, and the first year of operation and maintenance of the B2M Line. It is expected that thereafter a much smaller level of effort will be required, because procedures will have been established and operations are expected to be stable over the period.

Hydro One determined that it is appropriate to have the portion (percentage) of total Transmission Common Corporate Costs allocated to the B2MLP remain constant over the business plan period, 2014-2019. Black & Veatch agrees with this approach, for the following reasons:

- The amounts allocated are based on a normal average year and do not reflect the higher level of costs in year one.
- The costs allocated to the B2MLP are small and reasonably determinable, and the changes that would result from computing the numbers annually would be minimal in dollar terms and not worth the time. Many of the year one costs will be incurred prior to the closing of the transaction and are prior to the time scope of this report.
- Stability of costs benefits the B2MLP in planning and rate setting.

B. ALLOCATION PERCENTAGES

To determine the portion of Transmission Common Corporate Costs to allocate to the B2MLP, Hydro One personnel reviewed each activity performed by the departments included in Common Corporate Costs, and determined the estimated percentage of each activity that will be devoted to the B2MLP over the period of the BP 2014-19. The Hydro One personnel who performed this review are familiar with the B2MLP and with the functions and services included in Common Corporate Costs. Their review included discussions with the departments that provide those functions and services, as appropriate, as well as review of the results by management of the B2MLP and supporting staff.

Black & Veatch reviewed the percentages assigned to each activity and obtained explanations for the percentages assigned. Based on our work, we believe that the percentages are reasonable estimates of the effort required to provide the functions and services to the B2MLP over the business plan period.

Exhibit A lists each activity required to provide the functions and services (i.e., each activity in the Common Corporate Costs Model) and the percentage of the activity allocated to the B2MLP based on the review. For each activity for which costs are allocated to the B2MLP, Exhibit A also includes a brief explanation of the work to be performed and any relevant considerations.

C. COSTS ALLOCATED TO THE B2MLP- RESULTS AND CONCLUSION

For each activity in the functions and services to be provided to the B2MLP, the percentage allocated to the B2MLP is multiplied by the cost of that activity in 2014 (reflected in BP 2014-19) as determined in Hydro One's Common Corporate Costs Model. The results are summed, to determine the total Common Corporate Costs to be allocated to the B2MLP. The computations and the results are shown in Exhibit A. Table 3 presents a summary of the results.

Based on our review, Black & Veatch believes that the allocation of Common Corporate Costs to the B2M Limited Partnership, for the functions and services to be provided by Hydro One, reflects cost causation and conforms to the OEB-accepted methodology for allocation of Hydro One's Common Corporate Costs.

Table 3 – Summary of Common Corporate Costs Allocated to B2MLP

Group	Function or Service	Common Corporate Costs for Year 2014 in BP 2014-19		
		Total Costs Distributed To Transmission	Transmission Costs Allocated To B2MLP	B2MLP % Of Transmission (Average All Activities)
Shared Services	Treasury	2,482,800	14,042	0.57%
Shared Services	Corporate Controller	13,392,259	40,039	0.30%
Shared Services	Taxation	1,330,270	18,319	1.38%
Shared Services	Real Estate	7,882,026	21,603	0.27%
Shared Services	Regulatory Affairs	3,221,295	29,212	0.91%
Shared Services	Business Planning & Decision Support	1,250,623	20,851	1.67%
Operations	Security Operations	2,203,474	10,189	0.46%
Corporate Relations	Corporate Communications, External Relations & Executive Office	2,387,290	8,189	0.34%
Corporate Relations	First Nations and Métis Relations	1,861,275	16,475	0.89%
General Counsel & Secretariat	General Counsel & Secretariat	5,355,780	33,888	0.63%
Inergi	Finance	4,048,528	11,652	0.29%
All other		147,225,694		
Total		**$192,641,314**	**$224,459**	**0.12%**

Review of Allocation of Common Corporate Costs to B2M Limited Partnership

Group	Function or Services	L / N L	Line Index	Activities Performed		% B2M	Transmission-Year 1	$$ to B2M
HOI	President/CEO Office	L	1	Establish performance targets for safety, customer service, reliability			33,338	-
HOI	President/CEO Office	L	2	Provide strategic direction and manage the company to meet the targets of safety, customer service, reliability			133,352	-
HOI	President/CEO Office	L	3	Develop and maintain relationships with major customers and customer groups			133,352	-
HOI	President/CEO Office	L	4	Develop and maintain relationships with regulators, shareholder, lenders			117,300	-
HOI	President/CEO Office	L	5	Monitor, assess and remediate risks to operational and financial performance			66,676	-
HOI	President/CEO Office	L	6	Influence / Ensure company can adapt to changing regulatory framework and economic conditions			133,352	-
HOI	President/CEO Office	L	7	Plan for management succession			33,338	-
HOI	President/CEO Office	N	1	General Departmental Expenses			158,100	-
HOI	Chair	L	1	OVERALL ASSIGNMENT OF TIME			162,276	-
HOI	Chair	N	1	General Departmental Expenses			13,548	-
HOI	CFO Office	L	1	Review and approve financial and investment decisions and Provide input to strategy and business plans			83,074	-
HOI	CFO Office	L	2	Provide oversight to Finance functions in timely, reliable reporting information to HO, subs, regulators, investors, shareholder			64,921	-
HOI	CFO Office	L	3	Provide oversight to Human Resources			3,485	-
HOI	CFO Office	L	4	Provide oversight to Labour Relations			3,485	-
HOI	CFO Office	L	5	Provide oversight to Regulatory Affairs			32,229	-
HOI	CFO Office	L	6	Ensure financial services are provided efficiently and reliably			19,673	-
HOI	CFO Office	L	7	Ensure integrity of, and compliance with, internal controls over regulatory, financial, accounting activities			26,337	-
HOI	CFO Office	L	8	Monitor performance against operational, financial and regulatory targets			27,691	-
HOI	CFO Office	L	9	Ensure sufficient revenue for operating, financial and regulatory needs			14,143	-
HOI	CFO Office	L	10	Support BOD			10,607	-
HOI	CFO Office	L	11	Ensure access to capital on reasonable terms			2,000	-
HOI	CFO Office	L	12	Provide oversight to Management Investment			5,227	-
HOI	CFO Office	L	13	Provide oversight to Board Investment Pension			3,485	-
HOI	CFO Office	L	14	Provide oversight to Regulatory Committee			3,825	-
HOI	CFO Office	L	15	Provide oversight to Audit Finance Committee			7,561	-
HOI	CFO Office	L	16	Provide oversight to Business Transformation			1,700	-
HOI	CFO Office	L	17	Provide oversight to Outsourcing			11,203	-
HOI	CFO Office	L	18	Provide oversight to Supply Chain			11,203	-
HOI	CFO Office	L	19	Provide oversight to Fleet Services			2,970	-
HOI	CFO Office	L	20	Provide oversight to Real Estate and Facilities			5,141	-
HOI	CFO Office	L	21	OTHER DEPARTMENT ACTIVITIES			0	-
HOI	CFO Office	N	1	General departmental expenses			49,511	-
HOI	Treasurer's Office	L	1	Review and approve financial and investment decisions			23,304	-
HOI	Treasurer's Office	L	2	Ensure access to capital on reasonable terms			23,323	-
HOI	Treasurer's Office	L	3	Keep senior management and Hydro One Board Member's apprised on the risks, liquidity & financial position of the company, capital market conditions, financing and risk management strategies, plans and actions			16,326	-
HOI	Treasurer's Office	L	4	Represent the company before customers, regulators, shareholder, lenders, creditors and financial intermediaries			20,612	-
HOI	Treasurer's Office	L	5	Pension Management			6,094	-
HOI	Treasurer's Office	L	6	Oversight of Corp Finance- Treasury			137,268	-
HOI	Treasurer's Office	L	7	0			0	-
HOI	Treasurer's Office	L	8	0			0	-
HOI	Treasurer's Office	L	9	0			0	-
HOI	Treasurer's Office	N	1	General Departmental Expenses			(228,780)	-
HOI	Pension	L	1	Pension cost			580,279	-

Group	Function or Services	L / N L	Line Index	Activities Performed		% B2M	Transmission-Year 1	$$ to B2M
HOI	Pension	N	1	Pension cost			(580,279)	-
HOI	Board	N	1	Audit Fee			493,341	-
HOI	Board	N	2	General departmental expenses			433,524	-
HOI	Corp. Secretariat	L	1	OVERALL ASSIGNMENT OF TIME			153,654	-
HOI	Corp. Secretariat	N	1	General Departmental Expenses			52,909	-
HOI	General Counsel - VP	L	1	OVERALL ASSIGNMENT OF TIME			223,717	-
HOI	General Counsel - VP	N	1	General Departmental Expenses			5,291	-
HOI	Donations	N	1	Donations			0	-
Shared	Outsourcing Services	L	1	Inergi Contract Management			882,844	-
Shared	Outsourcing Services	N	1	General Departmental Expenses			23,939	-
Shared	Outsourcing Services	N	2	Inergi Costs/Consultants			1,493,800	-
Shared Services	Treasury	L	1	Liquidity Management, Debt Issuance and Financial Risk Management	Issues are allocated once upon creation and only minimal annual maintenance is required	1.0%	580,739	5,807
Shared Services	Treasury	L	2	Regulatory and Credit Rating Support			82,668	-
Shared Services	Treasury	L	3	Investor Relations			181,869	-
Shared Services	Treasury	L	4	Banking Operations and Account Management	Monthly reconcillations but number of transactions will be minimal	2.0%	347,205	6,944
Shared Services	Treasury	L	5	Insurance & Risk Management- Purchasing	partnership will have specific insurance requirements but those will be infrequent	2.0%	64,527	1,291
Shared Services	Treasury	L	6	Insurance- Claims			89,526	-
Shared Services	Treasury	L	7	Insurance- Support			80,658	-
Shared Services	Treasury	L	8	Enterprise Risk Management			193,580	-
Shared Services	Treasury	L	9	OTHER DEPARTMENT ACTIVITIES			0	-
Shared Services	Treasury	N	1	Claims			416,772	-
Shared Services	Treasury	N	2	General liability			352,173	-
Shared Services	Treasury	N	3	Directors & Officers insurance policy			72,408	-
Shared Services	Treasury	N	4	Fiduciary insurance policy			11,841	-
Shared Services	Treasury	N	5	0			0	-
Shared Services	Treasury	N	6	0			0	-
Shared Services	Treasury	N	7	General departmental expenses			8,835	-
Shared Services	Corporate Controller	L	1	Accting policies; External reports; External audit / review	Additional financial statements and audit support will be required	3.0%	721,133	21,634
Shared Services	Corporate Controller	L	2	Business Plan (incl. Financial Modeling & Analysis); Internal reports; Year-end projections			49,274	-
Shared Services	Corporate Controller	L	3	Regulatory Finance Activities			48,146	-
Shared Services	Corporate Controller	L	4	Manage Inergi- General and Inergi- Finance contract			72,510	-
Shared Services	Corporate Controller	L	5	Revenue analysis and reporting			135,065	-
Shared Services	Corporate Controller	L	6	Corporate accounting and Monitor and support Financial systems			672,743	-
Shared Services	Corporate Controller	L	7	Internal Controls/ Bill 198 and Compliance- New projects			579,332	-
Shared Services	Corporate Controller	L	8	Internal Controls/ Bill 198 and Compliance- Sustainment / ongoing			321,115	-

Group	Function or Services	L / N L	Line Index	Activities Performed		% B2M	Transmission-Year 1	$$ to B2M
Shared Services	Corporate Controller	L	9	Operational Acct & LOB Support			3,614,709	-
Shared Services	Corporate Controller	L	10	Payroll/TRC (BASC)			988,818	-
Shared Services	Corporate Controller	L	11	IFRS/US GAAP			64,020	-
Shared Services	Corporate Controller	L	12	SAP Process / Reporting Improvements			211,454	-
Shared Services	Corporate Controller	L	13	Business Process Improvements			343,672	-
Shared Services	Corporate Controller	L	14	Corporate Card Charge (BASC)			1,118,089	-
Shared Services	Corporate Controller	L	15	Performance Reporting	There will be performance reporting against a minimal set of activities	2.0%	920,269	18,405
Shared Services	Corporate Controller	L	16	Work Management Reporting			1,007,618	-
Shared Services	Corporate Controller	L	17	Project Accounting/Project Analyst			1,595,394	-
Shared Services	Corporate Controller	L	18	0			0	-
Shared Services	Corporate Controller	L	19	0			0	-
Shared Services	Corporate Controller	L	20	OTHER DEPARTMENT ACTIVITIES			0	-
Shared Services	Corporate Controller	N	1	Actuarial Consultants			133,797	-
Shared Services	Corporate Controller	N	2	Bill 198, Corp Controllership			630,149	-
Shared Services	Corporate Controller	N	3	General Departmental activities			164,951	-
Shared Services	Taxation	L	1	Compliance activities including tax filings and audits	Sepearate Tax filings and returns will be required	5.0%	362,492	18,125
Shared Services	Taxation	L	2	Tax Planning			258,907	-
Shared Services	Taxation	L	3	Support Debt issuance			19,210	-
Shared Services	Taxation	L	4	Special Projects			143,679	-
Shared Services	Taxation	L	5	Support regulatory filings	Support regulatory cases from time to time	1.0%	19,446	194
Shared Services	Taxation	L	6	Support Construction activities			0	-
Shared Services	Taxation	L	7	Support SAP Implementation			0	-
Shared Services	Taxation	L	8	Support Transition to IFRS			0	-
Shared Services	Taxation	L	10	OTHER DEPARTMENT ACTIVITIES			276,752	-
Shared Services	Taxation	N	1	Tax Consultants			179,844	-
Shared Services	Taxation	N	2	General Departmental activities			69,940	-
Shared Services	Real Estate	L	1	Supporting Rate Filling Regulatory			12,911	-
Shared Services	Real Estate	L	2	Real Estate - Manage & Acquire ROW & Easements	Based on # of km - average amount of management expected	0.6%	3,371,706	20,463

Group	Function or Services	L / N L	Line Index	Activities Performed		% B2M	Transmission- Year 1	$$ to B2M
Shared Services	Real Estate	L	3	Manage property taxes and property rights payments and appeals	Based on # of km - average amount of management expected	0.6%	187,874	1,140
Shared Services	Real Estate	L	4	Manage SLU Revenue Programs			1,268,182	-
Shared Services	Real Estate	L	5	Manage Employee Relocation Program			255,960	-
Shared Services	Real Estate	L	6	VP Office			223,360	-
Shared Services	Real Estate	L	7	Common (Admin)			673,753	-
Shared Services	Real Estate	N	1	Supporting Rate Filling Regulatory	Support regulatory cases from time to time	1.0%	0	-
Shared Services	Real Estate	N	2	Real Estate - Manage & Acquire ROW & Easements			674,559	-
Shared Services	Real Estate	N	3	Manage property taxes and property rights payments and appeals			77,581	-
Shared Services	Real Estate	N	4	Manage SLU Revenue Programs			1,128,155	-
Shared Services	Real Estate	N	5	Manage Employee Relocation Program			0	-
Shared Services	Real Estate	N	6	VP Office			7,986	-
Shared Services	Regulatory Affairs	L	1	Major Projects and Partnerships			393,242	-
Shared Services	Regulatory Affairs	L	2	Compliance			305,605	-
Shared Services	Regulatory Affairs	L	3	Regulatory Policy and Support			1,513,544	-
Shared Services	Regulatory Affairs	L	4	Major Applications	Labour associated with anticipated small COS proceeding every 2 years	5.0%	584,245	29,212
Shared Services	Regulatory Affairs	L	5	VP			130,831	-
Shared Services	Regulatory Affairs	N	1	All Other Costs			293,829	-
Shared Services	Reg. Affairs - OEB Cost	N	1	OEB Billed costs			4,071,509	-
Shared Services	Reg. Affairs - NEB Cost	N	1	NEB Costs			1,253,549	-
Shared Services	Reg. Affairs - Rate Hearings	N	1	Incremental Rate Hearing Costs			1,126,000	-
Shared Services	BP&DS	L	1	Business Planning and Other	Separate business plan including instructions will be prepared	3.0%	695,024	20,851
Shared Services	BP&DS	L	2	Regulatory Finance - Major Rate Apps			0	-
Shared Services	BP&DS	L	3	Regulatory Finance - Monthly Reporting			0	-
Shared Services	BP&DS	L	4	Decision Support			381,538	-
Shared Services	BP&DS	L	5	Health and Safety			128,768	-
Shared Services	BP&DS	L	10	OTHER DEPARTMENT ACTIVITIES			0	-
Shared Services	BP&DS	N	1	General departmental expenses			13,314	-
Shared Services	BP&DS	N	2	Lead Lag Study			9,898	-
Shared Services	BP&DS	N	3	Cost Allocation Study			17,183	-
Shared Services	BP&DS	N	4	Common Asset Study			2,397	-
Shared Services	BP&DS	N	5	Overhead Study			2,500	-

Group	Function or Services	L / N L	Line Index	Activities Performed		% B2M	Transmission-Year 1	$$ to B2M
Operations	Business Architecture	L	1	Manage Enterprise Business Processes			330,254	-
Operations	Business Architecture	L	2	Manage Enterprise Reporting and Analytics			495,381	-
Operations	Business Architecture	L	3	Support Cornerstone Value Realization Program			122,759	-
Operations	Business Architecture	L	4	Provide and assess key performance indicators and measures			165,127	-
Operations	Business Architecture	L	5	Provide Application Support and Coordinate, track and improve training curriculum and develop power user network			1,115,581	-
Operations	Business Architecture	L	6	Identify, develop, assess, and implement strategic solutions to improve upon the Cornerstone and related assets			613,795	-
Operations	Business Architecture	L	10	OTHER DEPARTMENT ACTIVITIES			149,626	-
Operations	Business Architecture	N	1	General Departmental Expenses			250,708	-
Operations	Business Architecture	N	10	OTHER DEPARTMENT ACTIVITIES			0	-
Operations	PSIT	L	1	Support to backbone, PCs and applications; Support internal telecommunications			2,202,027	-
Operations	PSIT	L	2	Develop systems required by operating businesses to meet changes in technical, operating and regulatory requirements			1,468,018	-
Operations	PSIT	L	3	Support Asset Management activities and projects			1,468,018	-
Operations	PSIT	L	4	Support Finance activities and projects			0	-
Operations	PSIT	L	5	Provide operational support for Transmission and Distribution activities			1,761,622	-
Operations	PSIT	L	6	Manage IT capital projects and IT strategy			2,202,027	-
Operations	PSIT	L	7	Support Inergi operations			0	-
Operations	PSIT	L	8	Other departmental activities			440,405	-
Operations	PSIT	L	10	OTHER DEPARTMENT ACTIVITIES			0	-
Operations	PSIT	N	1	General Departmental Expenses			(6,362,231)	-
Operations	PSIT	N	10	OTHER DEPARTMENT ACTIVITIES			0	-
Operations	BIT	L	1	Support to backbone, PCs and applications; Support internal telecommunications			1,159,337	-
Operations	BIT	L	2	Develop systems required by operating businesses to meet changes in technical, operating and regulatory requirements			1,411,435	-
Operations	BIT	L	3	Support Asset Management activities and projects			352,859	-
Operations	BIT	L	4	Support Finance activities and projects			319,062	-
Operations	BIT	L	5	Provide operational support for Transmission and Distribution activities			0	-
Operations	BIT	L	6	Manage IT capital projects and IT strategy			1,764,294	-
Operations	BIT	L	7	Support Inergi operations			633,115	-
Operations	BIT	L	8	Other departmental activities			296,847	-
Operations	BIT	N	1	General Departmental Expenses			131,117	-
Operations	Security Operations	L	1	Provide Security Services for Company Assets	routine security services required to monitor lines	0.5%	2,037,888	10,189
Operations	Security Operations	L	2	Theft of Power Program (Detection and Investigation of stolen electricity)			0	-
Operations	Security Operations	N	1	Provide Security Services for Company Assets			165,585	-
Operations	SVP Planning & Operating	L	1	Time Study Results			377,575	-
Operations	SVP Planning & Operating	N	1	Time Study Results			4,431,276	-
Operations	Distribution Development	L	1	Time Study Results			196,455	-
Operations	Distribution Development	N	1	Time Study Results			16,370	-
Operations	Transmission Projects Development	L	1	Time Study Results			12,356,960	-

Group	Function or Services	L / N L	Line Index	Activities Performed		% B2M	Transmission-Year 1	$$ to B2M
Operations	Transmission Projects Development	N	1	Time Study Results			3,364,350	-
Operations	Asset Strategy	L	1	Time Study Results			4,851,943	-
Operations	Asset Strategy	N	1	Time Study Results			783,014	-
Operations	Network Operations	L	1	Time Study Results			30,966,196	-
Operations	Network Operations	N	1	Time Study Results			727,364	-
Operations	Transmission Asset Management	L	1	Time Study Results			10,509,216	-
Operations	Transmission Asset Management	N	1	Time Study Results			586,420	-
Operations	Labour Relations	L	1	Advice, guidance and training to LOBs under the Collective Agreements			304,921	-
Operations	Labour Relations	L	2	Negotiate with Bargaining Units			76,230	-
Operations	Labour Relations	L	3	Participate in grievance and arbitration filings			228,691	-
Operations	Labour Relations	L	4	Participate in OLRB hearings			114,345	-
Operations	Labour Relations	L	5	Manage WFA Department			38,115	-
Operations	Labour Relations	N	1	Advice, guidance and arbitrations			59,014	-
Operations	Labour Relations	N	2	Bargaining & Labour Relations Board			31,777	-
Operations	EVP Office - Operations	L	1	Management of Operations group			680,831	-
Operations	EVP Office - Operations	L	2	Attendence at HOI Board meetings			25,053	-
Operations	EVP Office - Operations	L	3	Management of Remotes entity			0	-
Operations	EVP Office - Operations	N	1	Management of Operations group			235,310	-
Operations	EVP Office - Operations	N	2	Attendence at HOI Board meetings			0	-
Operations	EVP Office - Operations	N	3	Management of Remotes entity			0	-
Corporate Relations	Corporate Communications and External Relations and Executive Office	L	1	Provide stakeholder consultation advice and support	Responsible for reacting to any media inquiries. Non-traditional nature of the partnership make mdeia contact more likely	5.0%	141,936	7,097
Corporate Relations	Corporate Communications and External Relations and Executive Office	L	2	Provide strategic communications advice to support various corporate initiatives			0	-
Corporate Relations	Corporate Communications and External Relations and Executive Office	L	3	Provide Media Relations advice and support for infrastructure investment, corporate sponsorships, financial results, power restoration, etc.			127,563	-
Corporate Relations	Corporate Communications and External Relations and Executive Office	L	4	Develop and implement strategic employee communications plan			382,690	-
Corporate Relations	Corporate Communications and External Relations and Executive Office	L	5	Provide other internal communications support			765,380	-

Group	Function or Services	L / N L	Line Index	Activities Performed		% B2M	Transmission-Year 1	$$ to B2M
Corporate Relations	Corporate Communications and External Relations and Executive Office	L	6	Other Department Activities			74,609	-
Corporate Relations	Corporate Communications and External Relations and Executive Office	N	1	Provide stakeholder consultation advice and support			200,222	-
Corporate Relations	Corporate Communications and External Relations and Executive Office	N	2	Provide strategic communications advice to support various corporate initiatives			0	-
Corporate Relations	Corporate Communications and External Relations and Executive Office	N	3	Media Relations	Perodic media expenses for promotion (newspaper, radio)	0.6%	179,948	1,092
Corporate Relations	Corporate Communications and External Relations and Executive Office	N	4	Develop and implement strategic employee communications plan			299,913	-
Corporate Relations	Corporate Communications and External Relations and Executive Office	N	5	Provide Government Relations Advice and Support			179,948	-
Corporate Relations	Corporate Communications and External Relations and Executive Office	N	6	Other Department Activities			35,082	-
Corporate Relations	First Nations	L	1	Provide aboriginal consultation advice and support	Will require advice and guidance from FNM dept	2.0%	475,131	9,503
Corporate Relations	First Nations	L	2	Provide advice re aborignal HR strategies			154,417	-
Corporate Relations	First Nations	L	3	Provide strategic advice to Remotes			0	-
Corporate Relations	First Nations	L	4	OTHER DEPARTMENT ACTIVITIES			534,522	-
Corporate Relations	First Nations	L	10	OTHER DEPARTMENT ACTIVITIES			0	-
Corporate Relations	First Nations	N	1	General Departmental Expenses	Will require advice and guidance from FNM dept	1.0%	697,205	6,972
Corporate Relations	First Nations	N	10	OTHER DEPARTMENT ACTIVITIES			0	-
Corporate Relations	Executive Office	L	1	General			0	-
Corporate Relations	Executive Office	N	1	General Departmental Expenses			0	-
People & Culture	People and Culture	L	1	Administer Compensation & Benefits Programs			309,870	-
People & Culture	People and Culture	L	2	Decision Support			265,712	-
People & Culture	People and Culture	L	3	Talent Management: Hiring, Succession, Management Development Programs, Executive Coaching & High Potential Employee Assessments			442,726	-
People & Culture	People and Culture	L	4	Recruitment Solutions and Diversity: Diversity Programs, Grad Program, Student/Co-op Program, LOB Resourcing			708,057	-
People & Culture	People and Culture	L	5	Administer Pension Plan			398,567	-

Group	Function or Services	L / N L	Line Index	Activities Performed		% B2M	Transmission-Year 1	$$ to B2M
People & Culture	People and Culture	L	6	SAP Master Data Administration			88,697	-
People & Culture	People and Culture	L	7	Consulting support to LOBs and corporate functions			1,239,099	-
People & Culture	People and Culture	L	8	VP Human Resources			354,028	-
People & Culture	People and Culture	L	10	OTHER DEPARTMENT ACTIVITIES			0	-
People & Culture	People and Culture	N	1	Consulting			53,369	-
People & Culture	People and Culture	N	2	Talent Management			1,157,501	-
People & Culture	People and Culture	N	3	Recruitment Solutions & Diversity			210,668	-
People & Culture	People and Culture	N	4	Pension Administration			41,899	-
People & Culture	People and Culture	N	5	Compensation & Benefits			41,899	-
People & Culture	People and Culture	N	6	Decision Support			41,899	-
People & Culture	People and Culture	N	7	HR Master Data Management/Administration			41,899	-
People & Culture	People and Culture	N	8	VP Human Resources			751,615	-
People & Culture	People and Culture	N	10	OTHER DEPARTMENT ACTIVITIES			0	-
Customer Service	Customer Care Services	L	1	Time Study Results			350,290	-
Customer Service	Customer Care Services	N	1	Time Study Results			59,284	-
Customer Service	Strategy and Conservation	L	1	Time Study Results			47,120	-
Customer Service	Strategy and Conservation	N	1	Time Study Results			17,920	-
Customer Service	SVP Customer Ops	L	1	Time Study Results			198,189	-
Customer Service	SVP Customer Ops	N	1	Time Study Results			57,188	-
Customer Service	Distributed Generation	L	1	Time Study Results			105,963	-
Customer Service	Distributed Generation	N	1	Time Study Results			6,965	-
Customer Service	Customer Business Relations	L	1	Time Study Results			3,197,350	-
Customer Service	Customer Business Relations	N	1	Time Study Results			519,640	-

Group	Function or Services	L / N I	Line Index	Activities Performed		% B2M	Transmission- Year 1	$$ to B2M
Customer Service	TxDx Settlements	L	1	Time Study Results			444,177	-
Customer Service	TxDx Settlements	N	1	Time Study Results			47,627	-
Customer Service	Account Management Director	L	1	Time Study Results			186,896	-
Customer Service	Account Management Director	N	1	Time Study Results			7,808	-
Customer Service	Advanced Distribution	L	1	Time Study Results			0	-
Customer Service	Advanced Distribution	N	1	Time Study Results			0	-
Customer Service	Value Growth	L	1	Value Growth HONI			0	-
Customer Service	Value Growth	L	2	Value Growth HOI			0	-
Customer Service	Value Growth	N	1	Value Growth HONI			0	-
Customer Service	Value Growth	N	2	Value Growth HOI			0	-
Customer Service	Pricing	L	1	Time Study Results			611,621	-
Customer Service	Pricing	N	1	Time Study Results			41,273	-
Customer Service	VP Customer Service	L	1	Time Study Results			0	-
Customer Service	VP Customer Service	N	1	Time Study Results			0	-
General Counsel and Secretariat	General Counsel and Secretariat	L	1	Overall Assignment of Time			3,096,561	-
General Counsel and Secretariat	General Counsel and Secretariat	N	1	Consultants and External Legal Counsel	Occasional legal or consultant required related to non-traditional structure	3.0%	1,129,609	33,888
General Counsel and Secretariat	General Counsel and Secretariat	N	2	General departmental expenses			1,129,609	-
Audit	Audit	L	1	Audits			1,296,423	-
Audit	Audit	L	2	Purchasing			120,597	-
Audit	Audit	L	3	IMIT			402,955	-
Audit	Audit	L	4	Human Resources			66,388	-
Audit	Audit	L	5	Finance			157,329	-
Audit	Audit	L	6	Customers			21,603	-
Audit	Audit	L	7	Corporate Scorecard			200,065	-
Audit	Audit	L	8	Regulatory			26,316	-
Audit	Audit	N	1	General Departmental Expenses			81,258	-
Inergi	CSO - Customer Support Services	I	1	Inbound calls / correspondence			0	-
Inergi	CSO - Customer Support Services	I	2	Bill Production			0	-

Group	Function or Services	L/NI	Line Index	Activities Performed		% B2M	Transmission-Year 1	$$ to B2M
Inergi	CSO - Customer Support Services	I	3	Data Services- Timesheets for field personnel, Tx operations			0	-
Inergi	CSO - Customer Support Services	I	4	CSO Support- Management; Training, Communications, Support; Application support Business Analysts			0	-
Inergi	Settlement	I	1	Settlement activities			471,600	-
Inergi	Finance	I	1	General Accounting (F&A 1)	Period end journals and other activities required	2.0%	347,660	6,953
Inergi	Finance	I	2	Non Energy AR (F&A 2)			489,147	-
Inergi	Finance	I	3	Fixed Assets (F&A 3)	Some monitoring of Fixed asset ledger	1.0%	469,863	4,699
Inergi	Finance	I	4	Planing and Analysis (F&A 4)			2,100,393	-
Inergi	Finance	I	5	Centre of Excellence (F&A 5)			641,466	-
Inergi	AP	I	1	Managing AP			883,987	-
Inergi	SMS	I	1	0			0	-
Inergi	HR - Pay Services	I	1	Payroll Operations			1,648,409	-
Inergi	HR - Pay Services	I	2	COE - MDM			228,831	-
Inergi	HR - Pay Services	I	3	COE - Reconciliations			76,104	-
Inergi	HR - Pay Services	I	4	Print Impressions			43,488	-
Inergi	HR - Pay Services	I	5	COLA			98,304	-
Inergi	ETS - CSO Apps	I	1	Support CSO Applications			0	-
Inergi	ETS - Finance Apps	I	2	Support Finance Applications			4,362,480	-
Inergi	ETS - HR Apps	I	3	Support HR Applications			2,526,713	-
Inergi	ETS - Passport Apps	I	4	Support Passport Applications / Cornerstone			4,359,589	-
Inergi	ETS - Mkt Ready Apps	I	5	Support Market Ready Applications			1,027,462	-
Inergi	ETS - Telecom	I	6	Support Telecommunications Infrastructure			158,988	-
Inergi	ETS - Infra-structure Svc. / Misc. Apps	I	7	Direct Assignments			0	-
Inergi	ETS - Infra-structure Svc. / Misc. Apps	I	8	General Infrastructure Support			12,135,201	-
Inergi	ETS - Smart Meter	I	9	Smart Meter			0	-
Telecom Services	Oper / Carrier Mgmt	T	1	Operations and Carrier Management			3,827,593	-
Telecom Services	Data Services	T	2	Data Network Services –Admin			3,081,172	-
Telecom Services	Voice Services	T	3	Voice Services			1,605,894	-
Telecom Services	Field Services	T	4	Field Services			1,231,185	-
Telecom Services	Smart Meter	T	5	Smart Meter			0	-
TOTAL							**192,641,313**	**224,459**

OEB INTERROGATORY #11

Reference:

(1) Exhibit B, Tab 1, Schedule 3, Page 5

Interrogatory:

Preamble:

At the above noted reference, NRLP states:

> *The majority of NRLP's OM&A services are provided by HONI through a Service Level Agreement. The Agreement and the charges therefore are in accordance with the Affiliate Relationships Code and are billed on a cost basis. Efficiencies gained by HONI are passed through to NRLP. [emphasis added]*

Questions:

a) As stated in the above reference, Hydro One fulfils the majority of NRLP's OM&A services. Please indicate the OM&A services not covered by the service level agreement.

b) Please identify who, other than Hydro One, provides these services given that NRLP has no staff.

Response:

A limited number of items are not included in the Hydro One bundle of services. They include services such as: Insurance (provided by Marsh Canada Ltd.), Website hosting (provided by Netfirms Inc.), Website design services (provided by Creative Fire), Meeting Supplies (various), Printing (various), and other small items from time to time that might be required by the company.

OEB INTERROGATORY #12

<u>Reference:</u>
(1) Exhibit D, Tab 1, Schedule 1, Page 1
(2) B2M LP Settlement Proposal (EB-2018-0271), filed January 7, 2019

<u>Interrogatory:</u>
Preamble:
At the above noted reference, NRLP stated the following:

> *Given the nature of NRLP's assets, the performance of the equipment does not lend itself to applying the typical measures that might be in place for other transmitters. NRLP's assets consist of a single 230kV double circuit transmission line between the Allanburg and Middleport Transmission Stations, but do not include any terminal breakers or other operable assets. The demarcation point of each of the circuits is at a tower outside of the station, as noted in Exhibit B, Tab 1, Schedule 1. NRLP does not have any customer delivery points (or meter assets), which are the basis of interruption-based reliability performance measures like SAIDI and SAIFI. In addition to these operating characteristics, the life-cycle portfolio also detracts from meaningful comparisons. NRLP's single transmission line is relatively new; whereas other transmitters own a portfolio of assets that traverse the various stages of asset life.*
>
> *For NRLP to adopt a slate of performance measures similar to other transmitters would not readily provide meaningful comparisons. On this basis, NRLP proposes that System Average Interruption Frequency and System Average Interruption Duration not be measured. Furthermore, NRLP has no customers, so no Customer Focus measures have been proposed.*

At Page 16 of the B2M LP Settlement Proposal, accompanying these interrogatories as Attachment 1, the parties to the Settlement Proposal stated the following with respect to performance monitoring:

> *The Parties agree that in the absence of SAIDI and SAIFI metrics, additional information will be provided to reflect the performance of B2M LP's transmission circuits. B2M LP agreed that it would provide two performance metrics, which measure interruptions to Hydro One delivery points caused by B2M LP's circuits. The proposed contribution measures would not be B2M LP's T-SAIDI and T-SAIFI measure because B2M LP has no delivery points, but the denominator would be all Hydro One Networks Inc. delivery points.*

Question:

a) Subject to the OEB's approval of the B2M LP Settlement Proposal, would NRLP agree to track and report the same reliability performance measures agreed to for B2M LP in the Settlement Proposal? If not, why not?

Response:

a) In the recent B2M LP settlement, discussed at length in IR #28, B2M LP agreed to make best efforts to provide an additional metric attempting to isolate the contribution of NRLP's line to the total SAIDI of HONI. Without prejudice, NRLP would be willing to discuss the provision of a similar metric if a settlement conference is held.

OEB INTERROGATORY #13

Reference:
(1) Exhibit D, Tab 1, Schedule 1, Page 2

Interrogatory:
Preamble:
At the above noted reference, NRLP stated the following:

> *NRLP is proposing to track and demonstrate its performance by utilizing the same measures proposed for B2M LP in its recent application (EB-2019-0178). Filing a common set of measures as B2M LP serves to accomplish the following:*
>
> *a) Provide meaningful comparisons in asset performance with a similar transmitter,*
> *b) Minimize ratepayer costs by optimizing administrative costs through a single set of items, and,*
> *c) Provide the Board and customers with confidence that NRLP is meeting its five-year plan as described in this Application.*
>
> *The performance measures will be tracked annually, and the results of this tracking will be reported to the Board at the next proceeding. A description of the performance measures is provided in Appendix A of this schedule.*

Questions:
a) For each performance measure described in Appendix A, please indicate how in future proceedings NRLP will demonstrate achievement against each. For example, will a single metric to demonstrate performance against the Average System Availability (ASA) measure be established? For the NERC Vegetation Compliance, will NRLP only provide a statement indicating its compliance with FAC-003-02, or will NRLP detail the vegetation prevention related actions it has undertaken?

b) As it relates to the proposed ASA measure, on what basis will NRLP determine success? I.e., what is NRLP's proposed ASA target for 2020 against which success will be measured?

Response:

a) As described, the metrics will be captured annually and reported at the next proceeding.

- The ASA will be provided as a single percentage metric for each year, with 100% being complete availability. A single metric of ASA for NRLP circuits can demonstrate performance against the ASA for all Hydro One circuits of the same voltage level.
- The NERC Compliance will be a statement or attestation of compliance with the applicable standard.
- The ROE measure is part of the annual RRR submission to the OEB via the RRR portal. NRLP has offered an asymmetrical earnings sharing mechanism with a 100 bps range. This will also be filed in the next proceeding along with the ROE results.
- In the recent B2M LP settlement, discussed at length in IR #28, B2M LP agreed to make best efforts to provide an additional metric attempting to isolate the contribution of NRLP's line to the total SAIDI of HONI. Without prejudice, NRLP would be willing to discuss the provision of a similar metric if a settlement conference is held.

b) As NRLP only has a single dual-circuit line, there would be a small population bias, and this would make a single year ASA performance metric not meaningful. The ASA metric is a better indicator of longer-term performance. NRLP would suggest a rolling average ASA to measure its performance relative to Hydro One's circuits of the same voltage level in the same period.

OEB INTERROGATORY #14

Reference:

(1) Exhibit F, Tab 3, Schedule 1, Page 4

Interrogatory:

Preamble:

At the above noted reference, NRLP stated the following regarding its dispute resolution procedures with Hydro One Networks:

> *If the parties have a dispute under the agreement that cannot be resolved by a conference of their respective senior officers, a written notice outlining the specifics of the dispute will be passed to the parties' respective Presidents. Five business days after receipt of written notice, if the dispute remains unresolved, the matter is referred to arbitration for final resolution.*

Question:

a) As NRLP has no staff, please identify the senior officers who will represent NRLP during disputes. Please describe how these senior officers will monitor Hydro One's performance against its obligations defined in the services agreement. Please also identify whether and how NRLP will be independently represented in any dispute resolution processes.

Response:

a) Hydro One Indigenous Partnerships (HOIP) is the General Partner of NRLP. HOIP has a Managing Director who carries a fiduciary duty to represent the interests of NRLP. Furthermore, NRLP has an Advisory Committee made up of representatives of the partners that also review company matters. If such a dispute arose, the Managing Director would discuss it with the Advisory Committee and, where applicable, they would be expected to provide guidance and instruction on how to proceed.

OEB INTERROGATORY #15

Reference:

(1) Exhibit F, Tab 2, Schedule 1, Table 1
(2) Exhibit F, Tab 1, Schedule 1, Table 1

Interrogatory:

Preamble:

At the above noted first reference, NRLP identifies total OM&A costs of $0.83 million for 2020.

At the above noted second reference, NRLP identifies total OM&A costs of $0.85 million for 2020.

Question:

a) Please confirm the correct forecast of total OM&A costs for 2020.

Response:

a) The correct value is $0.85M.

OEB INTERROGATORY #16

Reference:

(1) Ontario provincial government's Bill 2 (i.e. Schedule 1 of Bill 2 is *the Hydro One Accountability Act, 2018*),[1] February 21, 2019 Directive, and the Hydro One Networks Distribution March 7, 2019 decision and order

Interrogatory:

Question:

a) Please confirm whether NRLP's executive compensation and costs for its board of directors are in compliance with Bill 2, the February 21, 2019 Directive, and the Hydro One Networks Distribution March 7, 2019 decision and order.[2]

Response:

a) NRLP does not have executive compensation or board of directors compensation.

[1] The Urgent Priorities Act, 2018
[2] EB-2017-0049

OEB INTERROGATORY #17

Reference:

(1) Exhibit G, Tab 1, Schedule 1
(2) Letter from OEB regarding Cost of Capital Parameters for 2020[1]
(3) B2M LP Settlement Proposal (EB-2018-0271), filed January 7, 2019

Interrogatory:

Preamble:

On page 4 of Exhibit G, Tab 1, Schedule 1, NRLP states:

> *NRLP will update the long-term debt rate for the 2020 Test year based on NRLP's weighted average of the OEB's deemed long-term debt rate for 2020 and the September 2019 Consensus Forecast, along with the proposed update of the return on common equity and deemed short-term interest rate.*

NRLP has also requested that its revenue requirement be updated for 2021 reflecting its actual debt re-issuance scheduled to occur in 2020.

On October 31, 2019, the OEB issued its approved cost of capital parameters for rates effective in 2020, in accordance with the OEB's policies in the *Report of the Board on the Cost of Capital for Ontario's Regulated Utilities*. The OEB's letter set out the following cost of capital parameters for 2020:

Cost of Capital Parameter	Value for Applications for rate changes in 2020
ROE	8.52%
Deemed LT Debt rate	3.21%
Deemed ST Debt rate	2.75%

[1] https://www.oeb.ca/sites/default/files/Ltr-2020-Cost-of-Capital-Update-20191031.pdf

The deemed LT (long-term) debt rate represents long-term or 30-year bond rate for a low-risk utility with a credit rating of A or higher. The deemed ST (short-term) rate represents a short-term, 3-month rate that a commercial bank would lend money at with a preferred and low-risk commercial customer.[2]

The OEB, in its *Handbook of Utility Rate Applications,* states the following:[3]

> *Utilities have the opportunity to recover their cost of capital through their rates. The OEB sets the cost of capital using a formula-based approach, which has streamlined the regulatory process considerably.[24] The same approach is used for all utilities, and the results are predictable, stable and fully transparent. The general expectation is that the cost of capital parameters will remain unchanged throughout the rate-setting term, typically 5-years.*
>
> *24 Report of the Board on the Cost of Capital for Ontario`s Regulated Utilities, December 11, 2009 and OEB Staff Report: Review of the Cost of Capital for Ontario's Regulated Utilities, January 14, 2016 and associated OEB cover letter.*

Questions:

a) Please explain how NRLP is proposing to update its 2020 long-term debt rate as documented above, and what specific information from Consensus Forecasts NRLP is intending to use.

b) In its evidence, NRLP has identified the weighted average debt rate to be 3.82% for 2020 and a forecast new long-term debt rate of 3.63% for 2021. This is well above the 3.21% deemed long-term debt rate that the OEB has calculated as being applicable for 2020.

    i. Please provide an updated forecasted long-term debt rate for the replacement debt based on current market conditions. If NRLP believes that the rate it forecasts will exceed the 3.21% deemed long-term debt rate issued by the OEB

[2] *Report of the Board on the Cost of Capital for Ontario's Regulated Utilities* (EB-2009-0084), December 11, 2009, Appendices C and D
[3] *Handbook of Utility Rate Applications*, October 13, 2016, Appendix 2, p. iii

and calculated in accordance with the OEB's cost of capital policy,[4] please provide a detailed explanation for its debt rate forecast.

c) Since the cost of capital parameters are not changed during an IRM plan (e.g., price cap or revenue cap), please explain how NRLP's proposals to update the long-term debt rate, and hence the cost of capital, in its revenue requirement for 2020 and 2021 outside of the revenue cap formula, are not "inconsistent with the Revenue Cap framework."[5]

d) Please update Table 1, shown on page 2 of Exhibit G, Tab 1, Schedule 1, to reflect the OEB's 2020 cost of capital letter of October 31, 2019,

e) Please update all tables in the application as appropriate to reflect the updates cost of capital parameters.

f) Please indicate whether NRLP's updated cost of capital parameters, and the proposed treatment for the new debt to be issued April 30, 2019, differ in any material way from what is documented in the B2M LP Settlement Proposal filed on January 7, 2020.

<u>Response:</u>

a) As discussed on line 25 page 1 to line 2 page 2 of Exhibit G, Tab 1 Schedule 1, to reflect the terms of the external issue in its revenue requirement, NRLP proposes to make a one-time update of the cost of long-term debt at the first annual update of rates for 2021[6]. This update will include the actual market rate achieved on the long-term debt to be issued in 2020.

As discussed on page 8 of the same schedule, NRLP assumes that, for rates effective January 1, 2020, the forecast interest rate for Hydro One Inc.'s debt issues will be based on the September 2019 Consensus Forecasts and the average of indicative new issue spreads for September 2019 that will be obtained from the Hydro One Inc. MTN dealer group for each planned issuance term.

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[4] *Report of the Board on the Cost of Capital for Ontario's Regulated Utilities* (EB-2009-0084), December 11, 2009

[5] Exhibit I, Tab 1, Schedule 5, part e)

[6] To minimize ratepayer costs, HOIP intends to execute the external issue of NRLP debt commensurate with the same issue of debt for B2M LP. The intended update of the debt rate for 2021 is intended to be identical to that of B2M LP.

Below is an updated Table 4 from Exhibit G, Tab 1 Schedule 1

Updated Table 4 - Forecast Yield for 2020 Issuance Terms – September 2019

	2020		
	5-year	**10-year**	**30-year**
Government of Canada	1.52%	1.50%	1.70%
Hydro One Spread	0.80%	1.16%	1.61%
Forecast Hydro One Yield	2.33%	2.66%	3.31%

Each rate comprises the forecast Government of Canada bond yield plus the Hydro One Inc. credit spread applicable to that term. The ten-year Government of Canada bond yield forecast for 2020 is based on the average of the three-month and 12-month forecast from the September 2019 Consensus Forecast. The five-year Government of Canada bond yield forecasts are derived by subtracting the September 2019 average spreads (five-year to ten-year for the five-year forecast) from the ten-year Government of Canada bond yield forecast. The thirty-year Government of Canada bond yield forecasts are derived by adding the September 2019 average spreads (30-year to ten-year for the 30-year forecast) to the ten-year Government of Canada bond yield forecast. Hydro One's credit spreads over the Government of Canada bonds are based on the average of indicative new issue spreads for September 2019 obtained from the Company's MTN dealer group for each planned issuance term.

Based on updated forecast rates, NRLP has calculated the weighted average debt rate to be 3.05% for 2020 and the forecast long-term debt rate is 2.94% for 2021. Please consider pages 1 and 2 of Attachment 1 of this IR response as an update to Exhibit G, Tab 1, Schedule 2.

b)

i. Updated forecast debt rates based on September 2019 Consensus Forecast and September 2019 data are updated in Table 4 in response to part (a). Updated weighted average rates of 3.05% for 2020 and the forecast new long-term debt rate of 2.94% for 2021, which are both below the 3.21% deemed long-term debt rate issued by the OEB. As discussed on lines 13 to 15, page 5 of Exhibit G, Tab 1 Schedule 1, the long-term debt rate for 2020 is calculated as the weighted average cost rate of 3.21% on its deemed long-term debt until April

30, 2020 (based on 2019 OEB cost of capital parameters), and forecast debt planned to be issued in 2020. The reason for using the deemed long-term debt rate is discussed on lines 14 to 16, page 4 of Exhibit G, Tab 1 Schedule 1, consistent with the OEB's policy, stated on page 54 of its Cost of Capital report, the deemed long-term debt rate will be used where an electricity distribution utility has no actual debt.

c) Underlying the intent of the Revenue Cap Framework is the fact that the base year should represent the recovery of fair and prudent costs. A unique circumstance for NRLP (and B2M LP concomitantly), is that materially all of its Long Term Debt needs are to be refinanced simultaneously during the rate period. This creates refinancing risk for both the utility and customers.

NRLP's proposal to reduce this risk in the future by implementing a one-time reset of the rates because of the extraordinary scale of the refinancing. This protects both the utility and ratepayers from inappropriate additional costs/savings. In terms of validity within the Revenue Cap Framework, NRLP would assert that this is an appropriate proposal under a Custom IR framework given the fact that the circumstances for NRLP are atypical. NRLP also notes that B2MLP and intervenors agreed on the exact same mechanism.

d) Below is an updated Table 1 of Exhibit G, Tab 1, Schedule 1, to reflect the OEB's 2020 cost of capital letter of October 31, 2019, and responses to the supplemental interrogatories.

Updated Table 1 - 2020 Cost of Capital

2020				
Amount of Deemed Return	**($M)**	**%**	**Cost Rate (%)**	**Return ($M)**
Long-term debt	65.99	56%	3.05%	2.01
Short-term debt	4.71	4%	2.75%	0.13
Common equity	47.14	60%	8.52%	4.02
Total	**117.84**	**100%**	**5.39%**	**6.16**

e) The revenue requirement tables outlined in Exhibit E, Tab 1, Schedule 1, which have been impacted by the Cost of Capital components, are provided below.

Table 1 - Revenue Requirement ($ Millions)

Components	2020
OM&A	0.85
Depreciation	1.59
Income Taxes	0.06
Return on Capital	6.16
Base Revenue Requirement	**8.66**
Deduct External Revenues and Other[2]	0.0
Add/(Deduct) Regulatory Accounts Disposition/Foregone/Other	6.38
Rates Revenue Requirement	**15.04**

Table 5 - Return on Capital ($ Millions)

	2020
Return on Debt	2.14
Return on Equity	4.02
Return on Capital	**6.16**

f) The proposed treatment for the new debt to be issued April 30, 2019, does not differ from what is documented in the B2M LP Settlement Proposal filed on January 7, 2020. As discussed on page 4 of Exhibit G, Tab 1 Schedule 1, Hydro One Inc. plans to issue debt to third party public debt investors at the same time that B2M LP's debt refinancing will be done in mid-2020, depending on market conditions at the time. The long-term debt rate on 2020 long-term debt differs from B2M LP's because B2M LP issued five-year debt on April 30, 2015, which matures on April 30, 2020, whereas NRLP currently has no externally issued debt. As discussed in part (b) i) above and on page 4 of Exhibit G, Tab 1 Schedule 1, consistent with the OEB's policy, stated on page 54 of its Cost of Capital report, the deemed long-term debt rate will be used where an electricity distribution utility has no actual debt.

Niagara Reinforcement Limited Partnership
Cost of Long-Term Debt Capital
Test Year (2020)
Year ending December 31

Line No.	Offering Date	Coupon Rate	Maturity Date	Principal Amount Offered ($Millions)	Premium Discount and Expenses ($Millions)	Net Capital Employed: Total Amount ($Millions)	Net Capital Employed: Per $100 Principal Amount (Dollars)	Effective Cost Rate	Total Amount Outstanding at 12/31/2019 ($Millions)	Total Amount Outstanding at 12/31/2020 ($Millions)	Avg. Monthly Averages ($Millions)	Carrying Cost ($Millions)	Projected Average Embedded Cost Rates
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
1	18-Sep-19	3.21%	30-Apr-20	66.88	0.00	66.88	100.00	3.21%	66.88	0.00	20.58	0.66	
2	30-Apr-20	2.33%	30-Apr-25	22.00	0.11	21.89	99.50	2.44%	0.00	22.00	15.23	0.37	
3	30-Apr-20	2.66%	30-Apr-30	22.00	0.11	21.89	99.50	2.72%	0.00	22.00	15.23	0.41	
4	30-Apr-20	3.31%	30-Apr-50	22.00	0.11	21.89	99.50	3.34%	0.00	22.00	15.23	0.51	
5		**Subtotal**							66.88	66.00	66.27	1.95	
6		Treasury OM&A costs										0.02	
7		Other financing-related fees										0.05	
8		**Total**							66.88	66.00	66.27	2.02	3.05%

Niagara Reinforcement Limited Partnership
Cost of Long-Term Debt Capital
2021
Year ending December 31

Line No.	Offering Date	Coupon Rate	Maturity Date	Principal Amount Offered ($Millions)	Premium Discount and Expenses ($Millions)	Capital Employed Total Amount ($Millions)	Capital Employed Per $100 Principal Amount (Dollars)	Effective Cost Rate	Total Amount Outstanding at 12/31/2020 ($Millions)	Total Amount Outstanding at 12/31/2021 ($Millions)	Avg. Monthly Averages ($Millions)	Carrying Cost ($Millions)	Projected Average Embedded Cost Rates
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
1	30-Apr-20	2.330%	30-Apr-25	22.0	0.1	21.9	99.50	2.44%	22.0	22.0	22.0	0.5	
2	30-Apr-20	2.660%	30-Apr-30	22.0	0.1	21.9	99.50	2.72%	22.0	22.0	22.0	0.6	
3	30-Apr-20	3.310%	30-Apr-50	22.0	0.1	21.9	99.50	3.34%	22.0	22.0	22.0	0.7	
4		**Subtotal**							66.0	66.0	66.0	1.9	
5		Treasury OM&A costs										0.0	
6		Other financing-related fees										0.1	
7		**Total**							66.0	66.0	66.0	1.9	2.94%

OEB INTERROGATORY #18

Reference:

(1) Exhibit A, Tab 3, Schedule 1, Page 2

(2) EB-2011-0268 Hydro One Networks Inc. – Transmission, Decision and Order, November 23, 2011, page 10

Interrogatory:

Preamble:

At the above noted first reference, NRLP stated that it is requesting an order allowing NRLP to utilize United States Generally Accepted Accounting Principles ("US GAAP") for financial reporting purposes.

At the above noted second reference, the OEB stated the following in a previous decision and order:

> *It should be noted that the Board does not regulate the accounting system adopted by any regulated utility for general financial reporting purposes. Unless otherwise constrained by other regulatory requirements, utilities are free to adopt whatever accounting system they choose for such purposes…*

Question:

a) Please explain why NRLP is seeking approval to use US GAAP for financial reporting purposes, considering the prior OEB direction at the above noted second reference. This direction was that the OEB "does not regulate the accounting system adopted by any regulated utility for general financial reporting purposes."

Response:

a) NRLP is requesting that the OEB approve the use of United States Generally Accepted Accounting Principles ("US GAAP") as its accounting standard for the purpose of rate setting, regulatory accounting, and regulatory reporting.

   For additional details, refer to the response in OEB Interrogatory #19.

OEB INTERROGATORY #19

<u>Reference:</u>

(1) Exhibit A, Tab 6, Schedule 1, Page 1

(2) EB-2011-0268 Hydro One Networks Inc. – Transmission, Decision and Order, November 23, 2011, pp. 5-6

(3) EB-2011-0268 Hydro One Networks Inc. – Transmission, Decision and Order, November 23, 2011, page 12

<u>Interrogatory:</u>

Preamble:

At the above noted first reference, NRLP stated the following:

> *NRLP is seeking permission to US GAAP as its accounting standard for the purpose of rate setting, regulatory accounting, and regulatory reporting as authorized under section 74 of the Act.*
>
> *In this regard, NRLP relies on the following provision of the Act:*
>
> *i. Subsection 70(1), which states that a licence under Part V of the OEB Act may prescribe the conditions under which a person may engage in an activity set out in section 57 and such other conditions as are appropriate having regard to the objectives of the Board and the purpose of the Electricity Act, 1998; and*
>
> *ii. Subsection 70(2), which provides examples of conditions that may be included in a licence, one of which, as set out in paragraph (f), is a condition requiring the licensee to maintain specific accounting records or to prepare accounting recordings according to specified principles.*
>
> *Both HONI's distribution and transmission businesses have received OEB approval to utilize US GAAP as its approved framework for rate setting, regulatory accounting and regulatory reporting. Approval to use US GAAP for NRLP*

> *will facilitate Hydro One Inc.'s consolidated reporting for securities filing purposes, thus avoiding incremental costs and/or reduced productivity.*

At the above noted second reference, some of the advantages and disadvantages of Hydro One Networks Inc. Transmission moving to US GAAP were outlined.

At the above noted third reference, the OEB stated the following:

> *In summary, the advantages of Hydro One transitioning to [US GAAP] argue in favour of granting the applicant's request to use [US GAAP] for regulatory purposes…*

Questions:

a) Please confirm that the advantages and disadvantages of NRLP using US GAAP for regulatory purposes would be similar to those as outlined in the previous Hydro One Networks Inc. Decision and Order referenced above.

b) If this is not the case, please explain.

Response:

a) Certain details regarding the preference for the use of USGAAP are influenced by specific characteristics of Hydro One Networks (e.g. – higher retained earnings – estimated at $2 billion). Otherwise, the advantages and disadvantages outlined in the previous Hydro One Networks Inc. Decision and Order referenced above would be similar for NRLP.

   As both Hydro One Networks Transmission and Distribution are currently using US GAAP as their approved framework for rate setting, regulatory accounting, and regulatory reporting, it is beneficial for NRLP to do the same. This simplifies Hydro One Inc.'s consolidated reporting for securities filing purposes, thus avoiding incremental costs, increased regulatory burden and/or reduced productivity. Hydro One Networks Transmission and B2M Limited Partnership (which account for approximately 96% of Ontario's transmission capacity) currently use US GAAP. This further supports the use of a consistent standard.

OEB INTERROGATORY #20

<u>Reference:</u>

(1) EB-2018-0275 Niagara Reinforcement Limited Partnership Decision and Order, Application for a Deferral Account, September 26, 2019, page 2

(2) EB-2018-0275 Niagara Reinforcement Limited Partnership Decision and Order, Application for a Deferral Account, September 26, 2019, page 6

(3) Exhibit A, Tab 3, Schedule 1, Page 16

(4) EB-2018-0275/0276/0278 Application for NRLP and Hydro One Networks Inc. Approvals for the NR Project, August 1, 2019, page 19 and Appendix 5 (page 2)

<u>Interrogatory:</u>

Preamble:

At the above noted first reference, NRLP stated the following regarding the NRLP deferral account (NRLPDA):

> *NRLP's request for the establishment of a new deferral account to record the revenue requirement for the NR project is approved…*

At the above noted second reference, NRLP stated the following:

> *The effective date of the deferral account is September 1, 2019, as requested by NRLP. The OEB is not approving the calculation of the interim revenue requirement or the specific accounting order put forward by NRLP at this time…*

At the above noted third reference, NRLP provided the following table regarding the proposed NRLPDA balance as at December 31. 2019:

Table 8 – Forecast Balance in NRLPDA on December 31 ($ Million)

Components	2019
OM&A	0.28
Depreciation	0.79
Income Taxes	0.03
Return on Capital	3.57
Start-Up and Development Costs Recovery	1.71
Total	**6.38**

At the above noted fourth reference, NRLP indicated that the start-up costs were estimated to be $1.15 million.

Question:

OEB staff has generated interrogatories below regarding the components of the proposed NRLPDA balance of $6.38 million.

OM&A

a) OEB staff notes that the NRLPDA 2019 OM&A of $0.28 million is calculated by taking the proposed 2020 OM&A of $0.85 million1 multiplied by 4/12 months. As noted at the above noted second reference, the OEB approved the NRLPDA effective September 1, 2019, so multiplying the proposed amount by 4/12 months may be reasonable.

   i. Please confirm whether NRLP is in agreement with OEB staff's calculations of the NRLPDA 2019 OM&A of $0.28 million.

   ii. If this is not the case, please explain.

Depreciation

b) OEB staff notes that the NRLPDA 2019 depreciation amount of $0.79 million reflects the following:

   - The proposed 2019 capital additions of $119.43 million[2]
   - The multiplication by 50% for the half year rule

[1] Exhibit A, Tab 3, Schedule 1, Page 9, Table 2
[2] Exhibit B, Tab 2, Schedule 1, Page 6

- The division by an average useful life of approximately 76 years

i. Please confirm whether NRLP is in agreement with OEB staff's calculations of the NRLPDA 2019 deprecation of $0.79 million.

ii. If this is not the case, please explain.

iii. Please confirm whether NRLP agrees that the NRLPDA 2019 depreciation should instead be $0.26 million. This amount would be comprised of the proposed NRLPDA 2019 depreciation of $0.79 million multiplied by 4/12 months to reflect the NRLPDA effective date of September 1, 2019.

iv. If this is not the case, please explain.

Income Taxes

c) OEB staff notes that the NRLPDA 2019 income taxes of $0.03 million is calculated by taking the proposed 2020 income taxes of $0.06 million[3] multiplied by 50%.

i. Please provide the rationale for NRLP having multiplied the proposed 2020 income taxes of $0.06 million by 50% to generate the NRLPDA 2019 income taxes of $0.03 million.

ii. Please confirm whether NRLP is in agreement with OEB staff's calculations of the NRLPDA 2019 income taxes of $0.03 million.

iii. If this is not the case, please explain.

iv. Please confirm whether NRLP is in agreement that the NRLPDA 2019 income taxes should instead by $0.02 million. This amount would be comprised of the proposed 2020 income taxes of $0.06 million multiplied by 4/12 months to reflect the NRLPDA effective date of September 1, 2019.

v. If this is not the case, please explain.

[3] Exhibit A, Tab 3, Schedule 1, Page 9, Table 2

Return on Capital

d) Please provide the calculations and rationale for the NRLPDA 2019 return on capital amount of $3.57 million, including any detailed spreadsheet analysis used to arrive at this amount.

Start-Up and Development Costs Recovery

e) Please provide more details on the NRLPDA 2019 Start-Up and Development Costs Recovery amount of $1.71 million, as there is no explanation in NRLP's application, including any detailed spreadsheet analysis used to arrive at this amount.

f) Please explain why the one-time setup cost was previously estimated to be $1.15 million in the deferral account application submitted on August 1, 2019 (as per the above noted fourth reference), and then updated to $1.71 million in the current application submitted on October 25, 2019. Please also explain the delta.

<u>Response:</u>

a) OM&A

Hydro One does not confirm the OEB staff's notion that the 2019 OM&A was calculated by using 2020 OM&A as a base. The 2019 forecast was built using estimates from the appropriate sources. The final OM&A estimate was subsequently calculated by applying the 4/12 months to the 2019 OM&A figure of $0.83 million. The 2020 estimate of $0.85 million was largely derived by inflating the 2019 estimate.

This describes how the estimate was calculated. Note that the actual amount of OM&A incurred in 2019 will be captured in the deferral account. Details of this are included in part e) of this response.

b) Depreciation

i. The calculation of the $0.79 million is confirmed.

ii. N/A

iii. NRLP disagrees with the OEB proposed calculation. The depreciation expense within the first year of service is based on the cost of the in-serviced assets, the appropriate depreciation rate, with the half-year rule applied - irrespective of the in-service date. For example, if the asset was put in place on March 31st, 2019, the appropriate depreciation expense requires only six months of depreciation. This accounting treatment is consistent with US GAAP.

iv. See response to iii.

c) Income Taxes

OEB staff correctly noted that the NRLPDA 2019 income taxes is $0.03 million, and the proposed 2020 income tax is $0.06 million. However, OEB staff was incorrect in concluding that the NRLPDA 2019 income tax estimate is based on the proposed 2020 income taxes multiplied by 50%.

It is important to note that on Page 3 of Exhibit F, Tab 6, Schedule 1, both the 2019 and 2020 tax amounts represent the anticipated Ontario corporate minimum tax ("OCMT"), a minimum tax computed based on financial statement income. As financial statement income represents the return on equity, which is based on the rate base, the 2019 and 2020 tax amounts are in fact, driven by the 2019 and 2020 average rate bases. As noted in Exhibit B-1-3, Attachment 1, Page 16, Table 4, NRLP is not anticipating the need for any planned capital spending in the 2020 test year.

Consequently, the 2019 ending rate base and the 2020 ending rate base would be similar but for depreciation expense. As the rate base used in determining the return of equity is an average of the year in question and the prior year, it is logical to expect the 2019 average rate base to be approximately half of the 2020 average rate base[4]. Thus, the reason why the NRLPDA 2019 income taxes appears to be 50% of the proposed 2020 income taxes is due to the combination of the minimum tax amounts being based on accounting return on equity, and the average rate base (being the basis of determining the return on equity) for 2019 being approximately 50% of the 2020 average rate base.

i. N/A – the NRLPDA 2019 income taxes of $0.03 million was not determined based on NRLP multiplying the proposed 2020 income taxes of $0.06 million by 50%. As discussed above, the 2019 and 2020 income taxes represented OCMT and were ultimately determined based on the average rate base for the respective year.

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[4] For further clarity, the 2019 average rate base would be calculated as (2018 ending rate base + 2019 ending rate base)/2. The 2018 ending rate base is 0 so the 2019 average would result in a number equal to approximately half of the total assets. The 2020 average rate base would include the full 2019 rate base amount and therefore be in line with the total asset amount.

ii. No – while NRLP's expected value of the NRLPDA 2019 income taxes is materially consistent with OEB Staff's value of $0.03 million, NRLP is not in agreement with OEB staff's calculations of the NRLPDA 2019 income taxes of $0.03 million.

iii. Please refer to the above narrative for details. As discussed, the 2019 income tax estimate was not based on 2020 income taxes but on the 2019 average rate base, which coincidentally is similar to the amount determined by multiplying 50% to 2020 average rate base.

iv. No – NRLP is not in agreement that the NRLPDA 2019 income taxes be adjusted to $0.02 million and that it should remain at $0.03 million.

v. Please refer to the above narrative for details.

d) Return on Capital

Please refer to Figure 1 for a copy of the table with details of the capital cost calculations included in the NRLPDA estimate.

The original calculation used a 6-month time frame of capital employed to estimate the costs. This has been adjusted for the actual transaction date of September 18, 2019. Included in this analysis is a revised calculation of the capital cost for 2019.

Table 1: Capital Cost Calculations for 2019

Rate Base (6-Months)				
	Opening Balance		0.00	
	Additions		119.43	
	Depreciation		(0.79)	
	Closing Balance		118.64	
	Average Rate Base		59.32	
Capital Structure				
	Long Term Debt	56%	33.22	
	Short Term Debt	4%	2.37	
	Equity	40%	23.73	
			59.32	
Capital Cost			**2019 Estimate**	**Revised***
	Long Term Debt	4.13%	1.37	0.79
	Short Term Debt	2.82%	0.07	0.04
	Equity	8.98%	2.13	1.23
			3.57	2.06

* The original calculation used a 6-month time frame to estimate capital cost.
The transaction was concluded on September 18, 2019.
Therefore, capital was employed for 12 days in September - 40% of a month
The revised number therefore include 3.4/6 * the original estimate.

e) Start-Up and Development Costs Recovery

NRLP has, as directed, been entering its relevant costs into the NRLPDA and is seeking recovery of those costs. While the amounts have not been audited, NRLP is providing a copy of its entries in the NRLPDA and is requesting $4.50 million for recovery. In the event that a difference arises during the final audited amount and the amount shown here, NRLP will bring those to the Board for consideration at a future proceeding. One difference that will exist is the interest improvement that will continue to accumulate in 2020 on the outstanding balance until the amount is recovered. This amount is estimated at approximately $10 thousand per month. The original estimate of the NRLPDA and the current amount entered in the account are included in Table 2 along with explanations for the variances.

Table 2: NRLPDA Reconciliation

NRLPDA Reconciliation ($million)		Original Estimate	Entries to Date	Variance	Note
OM&A		0.28	0.19	(0.09)	1
Transition Costs		1.71	1.39	(0.32)	2
Depreciation		0.79	0.80	0.01	
Return on Debt		1.44	0.83	(0.61)	3
Return on Equity		2.13	1.22	(0.91)	3
Income tax		0.03	0.06	0.03	4
	Total	**6.38**	**4.50**	**(1.89)**	

1 Maintenance Costs were less ($0.07) primary due to the circumstance that the forestry cycle did not call for work in Q4 of 2019. Also minor variances arose when actuals were entered on a Sept 18th commencement basis ($0.02) rather than a whole month charge as of September 1.

2 Most of the costs were in line with estimates ($0.32 net difference). The exception was a contingency amount of $250k that was not used. Legal costs were about 8% below estimate. Details provided below.

Start-Up OM&A Costs:		Estimate	Entered	NRLPDA Variance
Legal		0.98	0.91	(0.07)
Accounting		0.05	0.05	0.00
Inergi		0.43	0.43	0.00
Other / Contingency		0.25	0.00	(0.25)
	Total	1.71	1.39	(0.32)

3 See Table 1 for details of Capital Cost Variances

4 Estimates provided by tax based on the sum of monthly calculations. The final tax cost will not be available until completion of year end activities.

OEB INTERROGATORY #21

Reference:

(1) EB-2018-0275 Niagara Reinforcement Limited Partnership Decision and Order, Application for a Deferral Account, September 26, 2019, page 6

Interrogatory:

Preamble:

At the above noted reference, the OEB stated that it was not approving "the specific accounting order put forward by NRLP at this time." The OEB also stated that the methodology for recording entries in the deferral account, including the appropriateness of interest charges, was also to "be considered in the proceeding for the revenue requirement planned to be filed in October 2019" (i.e. the current proceeding).

Question:

a) Please provide NRLP's proposed accounting order for the NRLPDA, as it was not approved in the prior decision and order.

b) Please explain NRLP's rationale for including carrying charges on the NRLPDA.

Response:

a) Please see Accounting Order on the following page.

b) As per the Accounting Procedures Handbook, under 1508 Other Regulatory Assets: Carrying charges shall apply to this account. These amounts shall be calculated using simple interest applied to the monthly opening balances in the account (exclusive of accumulated interest) and shall be recorded monthly in a separate carrying charges sub-account related to this account. The interest rate shall be the rate prescribed by the Board.

TRANSMISSION ACCOUNTING ORDER
NRP Transmission Line Revenue Requirement Deferral Account

NRLP proposes the establishment of a new "NRP Transmission Line Revenue Requirement Deferral Account" to capture the preliminary revenue requirement relating to the operation associated with this project before such time that a S.78 Revenue Requirement application can be approved by the OEB and the associated Revenue Requirement can be included in the Uniform Transmission rates ("UTR") rates.

The account will be established as Account 1508, Other Regulatory Assets – Sub Account "NRP Transmission Line Revenue Requirement Deferral Account" effective September 1, 2019 to December 31, 2019. NRLP will record interest on the balance in the sub-account using the prescribed interest rates set by the Board. Simple interest will be calculated on the opening monthly balance of the account until the balance is fully disposed.

The following outlines the proposed accounting entries for this account:

USofA # Account Description

Dr: 1508	Other Regulatory Assets – Sub account "NRP Transmission Line Revenue Requirement Deferral Account"
Cr: 4110	Transmission Service Revenue

To record the revenue related to NRLP's 2019 Interim Revenue Requirement for the NRP transmission facilities.

Dr: 1508	Other Regulatory Assets – Sub account "NRP Transmission Line Revenue Requirement Deferral Account"
Cr: 6035	Other Interest Expense

To record interest improvement on the principal balance of the "NRP Transmission Line Revenue Requirement Deferral Account".

OEB INTERROGATORY #22

<u>Reference:</u>
(1) EB-2018-0275 Niagara Reinforcement Limited Partnership Decision and Order, Application for a Deferral Account, September 26, 2019, page 4

<u>Interrogatory:</u>
Preamble:
At the above noted reference, the OEB stated the following in a decision and order:

> *As part of its revenue requirement application, NRLP is requesting a new deferral account, the NRP Transmission Line Revenue Deferral Account (NRLPDA), to record the revenue requirement relating to the transmission assets transferred from HONI regarding the NR Project…*

Question:
a) Please confirm that the transmission assets transferred from Hydro One Networks regarding the NR Project have not already been incorporated into a prior OEB approved Hydro One Networks revenue requirement.

b) If the assets have been incorporated into a prior OEB approved Hydro One Networks revenue requirement, please explain.

<u>Response:</u>
a) After informing the Board of significant delays to the Project, on April 4, 2018, Hydro One informed the OEB of a material change to the project and was seeking approval to complete construction of the line in accordance with the conditions of Hydro One's leave to construct approval[1].

In that letter, specifically in the *Revenue Requirement Recovery* section, Hydro One explains that the costs associated with the NRP were in Hydro One Transmission's construction work-in-progress account. As a result of the pending partnership with The Six Nations of the Grand River and The Mississaugas of New Credit, Hydro One informed the OEB that it <u>would not</u> include the in-service addition of the NRP in its

[1] EB-2004-0476

2018 rate base, as part of its upcoming 2019- 2022 transmission rate filing. The letter has been provided as Attachment 7 of Exhibit I, Tab 1, Schedule 2 though it is already available in the OEB web drawer as a post-hearing filing for docket EB-2004-0476.

b) Please refer to a.

OEB INTERROGATORY #23

Reference:

(1) Exhibit F, Tab 6, Schedule 1, Page 4
(2) Exhibit B, Tab 2, Schedule 1, Page 4
(3) OEB Letter, Accounting Direction Regarding Bill C-97 and Other Changes in Regulatory or Legislated Tax Rules for Capital Cost Allowance, July 25, 2019
(4) Exhibit H, Tab 1, Schedule 1, Page 6
(5) Exhibit A, Tab 3, Schedule 1, Page 11

Interrogatory:

Preamble:

At the above noted first reference, NRLP stated the following:

> *CCA is calculated on a declining balance and, as a result, the amount of CCA available to reduce taxable income decreases. Under the Accelerated Investments Incentive program included in the Bill C-97, the Budget Implementation Act, 2019, No. 1, it provides for a first-year increase of CCA deductions for eligible capital assets acquired after November 20, 2018, and placed into service prior to January 1, 2028 (Accelerated CCA). Although the NRLP assets were placed into service in 2019, a large percentage of the assets were completed prior to the November 20, 2018 date. As such, only a small portion of the costs incurred during the period from November 21, 2018, to the in-service date would be eligible for the Accelerated CCA. This has been reflected in the computation of the taxable income for the applicable years.*

At the above noted second reference, NRLP provided the following table:

Table 1 – Chronology of Project Value for NRP

Reference Point	Project Value	(Planned) In-service Date
Leave to Construct – Jul 2005	$116.0 million	Summer 2007
Project Update Letter – Apr 2018	$129.2 million	May 2019
Current Application	$135.2 million	August 30, 2019

At the above noted third reference, the OEB stated that it “expects Utilities to record the impacts of CCA rule changes in the appropriate account (Account 1592 - PILs and Tax Variances and similar accounts for natural gas utilities and OPG) for the period November 21, 2018 until the effective date of the Utility’s next cost-based rate order.”

At the above noted fourth reference, NRLP has requested an accounting order to reflect Account 1592 which NRLP has been labelled “Tax Rate and Rule Changes Variance Account.”

At the above noted fifth reference NRLP indicated that there is no planned capital spending over the 2020 to 2024 planning period and no capital additions will be incurred.

Question:

a) Please provide a high level analysis to support NRLP’s assertion at the above noted first reference that a “large percentage of the assets were completed prior to the November 20, 2018 date.” In NRLP’s response, please consider the table it provided at the above noted second reference which shows approximately $6 million more capital expenditures were estimated to be incurred since its evaluation on April 2018, as well as $13.2 million more capital expenditures that were expected to be incurred since its evaluation on July 2005

b) Please explain whether the impacts of the CCA rule change on the relevant capital additions will be included in Account 1592, as well as NRLP’s requested accounting order, in 2019. If not, please explain why not.

c) NRLP has forecasted $0 capital additions from 2020 to 2024 and therefore, there will be no accelerated CCA to apply to new additions. Please describe how NRLP plans to implement accelerated CCA for tax purposes if there are capital additions in the next five years.

Response:

a) The OEB has been kept up-to-date on the status of this Project.

   In EB-2006-0501, the OEB provided Hydro One with relief from the carrying charges that it would incur on the funds used to finance the NRP, allowing Hydro One to recover AFUDC, based on the project’s $98 million cost incurred up to that point in time. The current application confirms that the total construction costs for the line are

$135.2M. Therefore, a large percentage of the assets was completed prior to the November 20, 2018 date. This is not surprising given the original intent was to in-service this asset in the Summer of 2007.

b) Yes, the impacts of the CCA rule change on the relevant 2019 capital additions, as reflected in the rate application, will be included in the proposed Tax Rate and Rule Changes Variance Account (Account 1592).

c) The tax rules that provide for accelerated CCA are reflected in the rate application period, and the CCA deduction will reflect the accelerated CCA impact to the extent the rules are still applicable at the time. In the event there are capital additions in the next five years, the CCA deduction attributable to these new capital additions will reflect the accelerated CCA impact.

OEB INTERROGATORY #24

Reference:

(1) Exhibit A, Tab 5, Schedule 1, Page 2

(2) Exhibit F, Tab 6, Schedule 1, Attachment 1

Interrogatory:

Preamble:

OEB staff has prepared the following table based on information from the above noted references and notes that there are some discrepancies that need to be explained, as follows.

OEB Staff Table A - NRLP Allocations ($ and %) to Affiliates

	Allocation % from Exhibit A, Tab 5, Schedule 1, Page 2 (Organization Chart)	Allocation % of Taxable Income - Based on Column D	Allocation % of Income for Corporate Minimum Tax Calculation - Based on Column E	$ of Taxable Income from Exhibit F, Tab 6, Schedule 1, Attachment 1	$ of Accounting Income for Corporate Minimum Tax Calculation from Exhibit F, Tab 6, Schedule 1, Attachment 1
	A	B	C	D	E
Hydro One Networks Inc	0.0%	54.0%	55.6%	$ (1.75)	$ 2.39
Hydro One B2M LP Inc.	54.9%	0.0%	0.0%	$ -	$ -
Hydro One Indigenous Partnerships GP Inc	0.1%	0.0%	0.0%	$ -	$ -
11100726 Canada Limited (Six Nations)	25.0%	25.6%	24.7%	$ (0.83)	$ 1.06
Mississaugas of the New Credit First Nation Toronto Purchase Trust	20.0%	20.4%	19.8%	$ (0.66)	$ 0.85
	100.0%	100.0%	100.0%	$ (3.24)	$ 4.30

Question:

a) Please confirm whether NRLP agrees with the calculations in the above OEB Staff Table A. If this is not the case, please explain.

b) Please explain the differences in the allocations of ownership, taxable income, and accounting income.

c) Please explain why taxable income (Column B and Column D) and accounting income (Column C and Column E) are allocated to Hydro One Networks Inc. at the above noted second reference, when Hydro One Networks Inc. is not included on the "Organization Chart for the NRLP Shareholder Structure" (Column A) at the above noted first reference.

Response:

Upon reviewing the referenced exhibits, it was noted that an error was made in Exhibit A, Tab 5, Schedule 1, Page 2. Instead of Hydro One B2M LP Inc. owning 54.9% of the limited partnership interest in NRLP, Hydro One Networks Inc., another wholly-owned entity of Hydro One Inc., is the actual entity that owns the 54.9% interest. NRLP apologizes for the confusion. Please see the response to IR # 9 for a corrected diagram.

a) Column A: NRLP agrees with the calculation but for the error noted above whereby Hydro One Networks Inc. is in fact the 54.9% limited partner as opposed to Hydro One B2M LP Inc. Moreover, while NRLP agrees with the calculation, NRLP is of the view that the heading “Allocation %” is misleading as the percentages noted only represent the ownership %.

   Based on the agreement reached amongst the partners and as documented in the limited partnership agreement, the allocation of accounting and taxable income is based on a prescribed formula, and as a result, the accounting and taxable income allocation % can vary year to year. While the percentages computed in Column A reflect the ownership percentage in NRLP by the various partners, the ownership percentage is only but the starting point to determining how accounting and taxable income is allocated. Please refer to response in b) for further details.

   Column B: based on the data in Column D, the calculation is correct and is the allocation of taxable income estimated for 2020 test year; however, it is worth noting that the allocation of taxable income can vary from year to year as a result of the agreement reached between the partners in how the taxable income will be allocated. Please refer to response in b) for further details.

   Column C: based on the data in Column E, the calculation is correct and is the allocation of accounting income estimated for 2020 test year; however, it is worth noting that the allocation of accounting income can vary from year to year as a result of the agreement reached between the partners in how the accounting income will be allocated. Please refer to response in b) for further details.

   Columns D and E: NRLP agrees with the values noted in Columns D and E as the taxable income and accounting income allocated to the partners in the 2020 test year, respectively.

b) NRLP, notwithstanding the error noted above, is a partnership set to be 54.9% owned by Hydro One Networks Inc., (HONI), 0.1% by Hydro One Indigenous Partnerships GP Inc. (HOIP GP), 25% by Six Nations of the Grand River Development Corporation (Six Nations), and 20% by Mississaugas of the Credit First Nation (Mississaugas).

While the proportionate investment percentage in NRLP provides for an allocable share of the accounting income, HONI and HOIP GP as the sole taxable partners (collectively, taxable corporations) are also allocated the taxes recoverable through annual revenue requirements. As such, the allocation of taxable and accounting income is not simply based on a straight proration of units held as outlined in the partnership agreement.

Any taxes arising from the revenue requirement should be allocated to Hydro One to cover the tax expense (First Nations are tax-exempt and have no taxes payable related to the partnership) and the remaining income (after allocating revenue relating to taxes to Hydro One) is allocated based on ownership percentage. Please refer to below for a calculation based on 2020 test year inputs to further different allocations of taxable income and accounting income.

	HONI	HOIP GP	Six Nations	Mississaugas	
Allocation of taxable income					
2020 taxable income/(loss)	(3.24)	(3.24)	(3.24)	(3.24)	[A]
Less: income tax in rates	(0.06)	(0.06)	(0.06)	(0.06)	Note 1
Amount to be allocated to partners	(3.30)	(3.30)	(3.30)	(3.30)	
Ownership %	**54.9%**	**0.1%**	**25.0%**	**20.0%**	
Sub-total	(1.81)	(0.00)	(0.83)	(0.66)	
Add: tax allocable only to taxable corporations	0.06	0.00	N/A	N/A	Note 1
Total allocation in the year	(1.75)	(0.00)	(0.83)	(0.66)	[B]
Effective %	**54.1%**	**0.1%**	**25.5%**	**20.4%**	[B]/[A]
Allocation of accounting income					
2020 accounting income	4.30	4.30	4.30	4.30	[C]
Less: income tax in rates	(0.06)	(0.06)	(0.06)	(0.06)	Note 1
Amount to be allocated to partners	4.24	4.24	4.24	4.24	
Ownership %	**54.9%**	**0.1%**	**25.0%**	**20.0%**	
Sub-total	2.33	0.00	1.06	0.85	
Add: tax allocable only to taxable corporations	0.06	0.00	N/A	N/A	Note 1
Total allocation in the year	2.39	0.00	1.06	0.85	[D]
Effective %	**55.5%**	**0.1%**	**24.7%**	**19.7%**	[D]/[C]

	HONI	HOIP GP	Six Nations	Mississaugas
Percentage - by ownership	54.9%	0.1%	25.0%	20.0%
Percentage - by taxable income allocation	54.1%	0.1%	25.5%	20.4%
Percentage - by accounting income allocation	55.5%	0.1%	24.7%	19.7%

Note 1 Six Nations and Mississaugas are not taxable; therefore, the revenue requirement related to income taxes is allocated only to the taxable partners (HONI and HOIP GP). The remaining icnome is allocated based on ownership percentage.

c) Hydro One Networks Inc. was not included on the “Organization Chart for the NRLP Shareholder Structure” (Column A) at the above noted first reference in error. Hydro One B2M LP Inc. is not an entity that has any ownership in NRLP. Had Hydro One Networks Inc. been correctly reflected as owning 54.9% in Exhibit A, Tab 5, Schedule 1, Page 2, both the taxable income and accounting income will be allocated to Hydro One Networks Inc.

OEB INTERROGATORY #25

Reference:

(1) Exhibit B, Tab 2, Schedule 1, Page 6

(2) EB-2006-0117, OEB Letter, November 28, 2006, Approval of Accounting Interest Rates Methodology for Regulatory Accounts

(3) OEB webpage titled "Prescribed Interest Rates for Accounts of Natural Gas and Electricity Distributors"[1]

(4) Accounting Procedures Handbook for Electricity Distributors, December 2011, Article 410, Accounting for Specific Items, Property, Plant & Equipment and Intangible Assets, page 27

Interrogatory:

Preamble:

At the above noted first reference, NRLP provided the following table regarding borrowing costs related to construction work in progress (CWIP). These borrowing costs are referred to as allowance for funds used during construction (AFUDC).

Table 2 – Annual AFUDC Breakdown

Year	AFUDC ($M)
Up to 2006	5.02
2007- 2017	0.00
2018	4.37
2019	3.01
Total	12.40

At the above noted second reference, the OEB indicated that AFUDC should not be based on the weighted average cost of capital, which would include an equity component. The OEB's current policy can be found at the above noted second reference and reflects only a debt component and excludes an equity component for calculating AFUDC.

The OEB's CWIP rates are based on the following data which can be found at the above noted third reference:

> *The prescribed interest rate for the construction work in progress (CWIP) account is equal to the FTSE TMX*

1 https://www.oeb.ca/industry/rules-codes-and-requirements/prescribed-interest-rates-accounts

> *Canada (formerly DEX) Mid Term Bond Index All Corporate yield.*

The OEB's policy regarding AFUDC is further described at the above noted fourth reference as follows:

> *Where incurred debt is acquired on an arm's length basis, the actual borrowing costs should be used for determining the amount of carrying charges to be capitalized to CWIP for rate making during the period, in accordance with IFRS. Where incurred debt is not acquired on an arm's length basis, the actual borrowing costs may be used for rate making, provided that the interest rate is no greater than the Board's published rates. Otherwise, a distributor should use the Board's published rates.*

OEB staff notes the following regarding US GAAP and AFUDC which differs from the OEB's policy, as the OEB policy does not allow the inclusion of an equity component. US GAAP ASC 980-835 generally describes that an allowance for funds used during construction, including a designated cost of equity funds, may be capitalized in specified circumstances as part of the acquisition cost of the related asset.

Question:

a) Please confirm that NRLP's proposed AFUDC amounts of $12.4 million do not reflect an equity component.

b) Please confirm that NRLP's proposed AFUDC amounts of $12.4 million are based on either the OEB's prescribed interest rates for CWIP found at the above noted third reference, or at NRLP's actual borrowing costs. Please explain how NRLP has addressed the OEB's policy at the above noted fourth reference, as the AFUDC borrowing costs depend on whether NRLP's debt is arm's length or non-arm's length.

c) If either of the above items is not the case, please explain and restate the AFUDC.

<u>Response:</u>

a) NRLP confirms that the proposed AFUDC amount does not reflect an equity component.

b) The proposed AFUDC amounts prior to 2006 are based on the prescribed OEB rates. The proposed AFUDC amounts in 2018 and onwards is based on the weighted average cost of debt.

c) See response above.

OEB INTERROGATORY #26

Reference:

(1) Exhibit A, Tab 4, Schedule 1, Page 5 & 6
(2) Exhibit H, Tab 1, Schedule 1, Page 5

Interrogatory:

Preamble:

At the above noted first reference, NRLP stated the following:

> *NRLP proposes to share, with customers, 50% of any earnings that exceed the OEB allowed regulatory ROE by more than 100 basis points in any year of the Revenue Cap IR term. The customer share of the earnings will be adjusted for any tax impacts and will be credited to a new deferral account for clearance at the time of NRLP's next rebasing. The calculation of the actual ROE for a Test year will use the OEB-approved mid-year rate base for that period.*

At the above noted second reference, NRLP provided an accounting order for the ESM deferral account.

Question:

a) Please clarify what these tax impacts are and what type of adjustments is expected.

b) Please revise the accounting order to include details on the proposed tax adjustment.

c) Please confirm that, if NRLP does incur any capital expenditures added to rate base during the 2020-2024 plan term, it would use the actual mid-year rate base instead of the forecasted rate base.

d) Please explain why a sub-account of Account 2435 is not used for carrying charges and why the debit is going to Account 4395 and not Account 6035 Other Interest Expense

Response:

a) The tax impacts mentioned in the above reference essentially aim to capture the tax associated with items that should be considered in arriving at total regulatory return on equity subject to earnings sharing. Certain expenditures could be incurred that are not included in the rate-making process in which case the tax associated with such expenditures should be adjusted. For example, any differences between the actual interest incurred and the allowable regulatory interest can also give rise to tax impact and should be reflected in the ESM calculation.

b) Please see Accounting Order on following page.

c) NRLP intends to use the OEB approved mid-year rate base in the ROE calculation.

d) A sub-account of Account 2435 is currently proposed for carrying charges, as detailed in the Accounting Order.

   Per the Accounting Procedures Handbook, Account 4395 *shall be used to record the amounts over the return on equity ceiling or in the earnings share mechanism that will be returned to ratepayers as part of the profit-sharing mechanism incorporated in the Performance-Based Regulation or Incentive Regulation plan. This account will also include the related accrued interest, as applicable. The corresponding Deferred Credit Account is 2435, Accrued Rate-Payer Benefit.*

NRLP ACCOUNTING ORDER

Transmission Accounting Order – ESM Deferral Account

NRLP proposes the establishment of a new "Earnings Sharing Mechanism ("ESM") Deferral Account" to record 50% of any earnings that exceed the regulatory return on equity reflected in this Application by more than 100 basis points in any year of the five-year term through NRLP's transmission revenue. Applicable tax adjustments will be made in the ROE calculation. The ROE calculation will use a methodology that is similar to what is outlined in the annual RRR 2.1.5.6 filing. The calculation of actual ROE will use the OEB approved mid-year rate base for that period. The ROE calculation is to be normalized for revenue impacting items such as entries that are recorded in the year which relate to prior years to normalize the in-year net income.

The account will be established as Account 2435, Accrued Rate-Payer Benefit effective January 1, 2020. NRLP will record interest on any balance in the sub-account using the interest rates set by the OEB. Simple interest will be calculated on the opening, monthly balance of the account until the balance is fully disposed.

The following outlines the proposed accounting entries for this deferral account.

USofA #	**Account Description**
DR: 4395	Rate-Payer Benefit Including Interest
CR: 2435	Accrued Rate-Payer Benefit

Initial entry to record the over-earnings realized in any year of the five-year term.

USofA #	**Account Description**
DR: 4395	Rate-Payer Benefit Including Interest
CR: 2435	Accrued Rate Payer Benefit

To record interest improvement on the principal balance of the ESM deferral account.

OEB INTERROGATORY #27

Reference:
(1) Exhibit C, Tab 2, Schedule 4, Page 1-3

Interrogatory:
Preamble:
At the above noted reference, NRLP provided some detail on the calculation of depreciation expense.

Question:
a) Please provide a breakdown of the depreciation schedule by the Uniform System of Accounts (USoA).

Response:
The referenced exhibit is presented by USofA description for the in serviced assets under NRLP. The corresponding USofA codes to those descriptions are listed in the table below:

USofA Description	USofA Code	Depreciation Expense ($) at Sep 30 2019	Depreciation Expense ($) at Dec 31, 2019
Towers and Fixtures	1720	250,041.92	508,083.84
Overhead Conductors and Devices	1730	141,874.16	283,748.30

Note that the above table corrects Exhibit C, Tab 2, Schedule 4. No land rights were transferred to NRLP as part of the sale.

OEB INTERROGATORY #28

Reference:

(1) Exhibit A, Tab 3, Schedule 1, pp. 5-6
(2) B2M LP Settlement Proposal (EB-2018-0271), filed January 7, 2019

Interrogatory:

Preamble:

At reference (1), NRLP states:

> *NRLP operates under unique circumstances unlike other transmission companies in Ontario when considering its corporate structure, asset holdings, and operating and management arrangements. NRLP's proposal reflects these circumstances …*

NRLP then provides a description of its "unique" circumstances.

OEB staff notes that there is another electricity transmitter, B2M Limited Partnership (B2M LP), similarly owned through a partnership of Hydro One Networks Inc. (Hydro One) and First Nations. B2M LP also owns a single transmission asset, with operations and maintenance provided through service agreements with Hydro One. B2M LP's asset, while slightly older than NRLP's, is still relatively young compared to the expected service life.

B2M LP filed a 5-year (2020-2024) revenue cap application in 2019, with a similar proposed revenue cap formula.[1] B2M LP's application, as updated through the proceeding, forecasts minimal capital expenditures during the plan term. A Settlement Proposal for B2M LP's 2020-2024 revenue cap plan was filed with the OEB on January 7, 2020, and is being deliberated on by the OEB.

Question:

a) Please identify whether, and if so, how, NRLP's circumstances differ from B2M LP's, in terms of ownership, asset age and condition, operations, etc. Please identify if any differences are material.

[1] EB-2019-0178

b) Through an Alternative Dispute Resolution process, B2M LP intervenors and OEB staff have reached a settlement proposal for a 5-year revenue cap plan with specific parameters. The settlement proposal has been filed with the OEB, and the OEB is currently deliberating on it. A copy of the settlement proposal is included as Attachment 1 to these interrogatories.

   i. Should the OEB accept B2M LP's revenue cap plan per the settlement proposal, please indicate whether a similar framework for the revenue cap plan would be reasonable for the 2020-2024 plan term. OEB staff notes that whether the same parameters should necessarily apply to NRLP will depend on specific information in NRLP's Application, including the responses to OEB staff's interrogatories.

   ii. If NRLP considers that alternative plan parameters and/or conditions than those in B2M LP's settlement proposal would be required, please identify what changes are needed, and the reasons for them.

Response:

NRLP's comment regarding its uniqueness was intended to refer to the fact that it is different than a 'typical' transmitter such as Hydro One Networks or Canadian Niagara Power to name a couple.

a) NRLP acknowledges that its circumstances are similar to B2M LP. Albeit,there are also numerous differences such both on the technical side and operationally, such as size, voltage, location, partners, structure, etc. However, the fundamental setup of the company is common to the two entities. Both partnerships include HONI owning a majority stake and First Nations with a minority share. The operational characteristics of the line are fundamentally the same as they both include one dual-circuit asset with neither having operable components nor customer delivery points.

   Germane to this interrogatory, both companies have a low level of capital expenditures compared to a typical utility since they both have relatively new assets. Therefore, the amount by which the Net Book Value[2] (NBV) of the asset is reduced by depreciation is not matched or exceeded by in-service capital additions as it commonly is with a

[2] In this context, Net Book Value refers to the original gross value of the asset less the accumulated depreciation logged against that asset. For these companies with no working capital, this is essentially the same as Rate Base.

'typical' utility. While many different events can change the dynamic[3] such events are not commonplace, and therefore, NRLP's rate base will generally decline over time with the cost of capital decrease commensurately and, all things being equal, the revenue requirement will goes down over time given a 'normal' year.

B2M LP also faces the reality of decreasing revenue requirement for the same reasons. Due to its lifecycle stage, B2M LP faces some unique cost increases that curtail much of the depreciation-driven decrease. Nonetheless, as pointed out in this interrogatory, B2M LP was able to come to a settlement agreement with intervenors[4] that proposed to include an annual "Capital Reduction Factor" in its annual IRM formula to acknowledge the situation described above.

NRLP acknowledges the same situation with its assets. While B2M LP has the additional cost challenge of rising income taxes that NRLP does not have at this time, NRLP has a distinct asset profile that causes differences in the relative, forecast OM&A costs.[5]

b) If the OEB was to accept the B2M LP's revenue cap plan per the settlement proposal, NRLP believes a similar framework for its revenue cap plan for 2020-24 would be reasonable. NRLP would be open to a discussion at a future settlement conference about proposing a similar mechanism in order to ensure ratepayers enjoy the effects of the reducing revenue requirement on an annual basis. Without prejudice, NRLP envisions the Capital Reduction Factor would be largely the same in form and scale and would likely seek minimal if any variation.

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[3] Events that can change the phenomena of a decreasing revenue requirement include but are not limited to such things as: increased vegetation management, income tax changes, destructive storms, changes in standards, changes in system topography, long term load changes, refinancing situations and many more.
[4] At time of writing, the B2M LP settlement agreement has been proposed to the Board panel but has not yet been approved.
[5] NRLP's asset is a different age and voltage than B2MLP's. Much of the NRLP line was built around 2006 and thus in 2020, the vegetation has already substantially reasserted itself. Moreover, NRLP is a 230 kV line (B2M is 500 kV) and thus has a smaller right of way. This connotes a higher risk of incursion.