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Joanne Richardson
Director – Major Projects and Partnerships
Regulatory Affairs

BY COURIER

September 24, 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-2017-0364– Hydro One Networks Inc.'s Section 92 – Lake Superior Link Project Application – Responses to Interrogatories

Please find attached an electronic copy of responses provided by Hydro One Networks Inc. to Interrogatory questions. Three hard copies will be sent to the Board on the morning of September 28, 2018, in advance of the oral hearing.

Below are the Tab numbers for each intervenor

Tab	Intervenor
1	Ontario Energy Board Staff
2	NextBridge
3	Bamkushwada Limited Partnership
4	Vulnerable Energy Consumers Coalition
5	School Energy Coalition
6	Power Workers' Union
7	Consumers Council of Canada
8	Independent Electricity System Operator
9	Biinjitiwaabik Zaaging Anishinaabek
10	East Loon Lake Campers' Association
11	Long Lake #58 First Nation

An electronic copy of the Interrogatory responses has been filed using the Board's Regulatory Electronic Submission System.

Please note that of the 500+ interrogatories received, confidential treatment is being sought on only three responses, specifically with respect to: the response to OEB Staff interrogatory 18, referenced as Exhibit I, Tab 1, Schedule 18; an attachment in response to NextBridge interrogatory 24, referenced as Exhibit I, Tab 2, Schedule 24, Attachment 1; and the response to

School Energy Coalition interrogatory 21, referenced as Exhibit I, Tab 5, Schedule 21. The said three responses contain either intellectual property or competitive pricing information that, if disclosed, would significantly affect the competitive position of the Applicant.

Sincerely,

ORIGINAL SIGNED BY JOANNE RICHARDSON

Joanne Richardson

OEB Staff Interrogatory # 1

Reference:

EB-2017-0364 Evidence, Hydro One's Application filed on February 15, 2018,
Exhibit B, Tab 5, Schedule 1, Page 1

Further to the options proposed in EB-2011-0140, Hydro One also considered a High Temperature, Low Sag (HTLS) conductor alternative. Conceptual engineering was performed to ascertain whether the required power transfer could be achieved by re-conductoring the existing East-West Tie line with a HTLS conductor. The findings of the study indicated that the solution was viable both functionally and commercially. However, this solution did not meet the IESO's requirements concerning bulk power transfer, while respecting the reliability requirements of the NERC TPL-001 standard.

Interrogatory:

a) What specific IESO requirements does the re-conductoring option not meet concerning bulk transfer capability? Does this specific option meet transfer capabilities below 450 MW?

b) What specific reliability requirements of the NERC TPL-001 does re-conductoring not meet? Does this specific option meet transfer capabilities below 450 MW?

c) If the re-conductoring did meet both the IESO and NERC TPL-001 requirements, would Hydro One have considered re-conductoring the entire existing East-West Tie line in whole or part?

d) Would re-conductoring provide the transfer capability of up to 450 MW and meet all applicable NERC and NPCC requirements? If yes, would the installation of new local generation of approximately 200 MW provide the balance of the power requirements to the Northwest area over the planning horizon under consideration?

e) If re-conductoring in part or whole was in fact a viable option, what would the impact be on:
   i. The estimated capital cost of the project, including station costs
   ii. Routing and land requirements
   iii. Environmental approvals outside and inside Pukaskwa National Park
   iv. Public Consultations
   v. Indigenous consultations and participation, and
   vi. Construction schedule and planned in-service date.

f) If re-conductoring in part or whole was in fact a viable option, would any structures have to be replaced?

Response:

a) The IESO planning criteria and NERC TPL-001-4 standard require the system to meet certain performance requirements for different categories of contingencies. One of these categories involves the loss of a transmission circuit when another transmission circuit is out of service (called N-1-1 event). By replacing the existing EWT conductors with HTLS conductors, the N-1-1 event will result in separation of the Northwest system from the rest of Ontario. Although the NERC TPL requirements could be met by rejecting sufficient amount of load in the Northwest, the IESO's requirements for the amount of load loss and its duration (restoration time) could be difficult to meet in drought years when hydroelectric generation in the Northwest would be low. As a result of this high-level assessment, the reconductoring option was rejected.

   Hydro One did not assess the viability of the HTLS option for transfer capabilities below 450 MW. The anticipated transfer requirements were 450 MW in short-term and 650 MW in mid-term, as indicated in various IESO need assessment reports.

b) Please see the answer to part a) above, which covers both the IESO and NERC requirements.

c) The reconductoring option was considered for the whole line and, as indicated in part a) above, it was rejected.

d) Various transfer levels, e.g. 450 MW, or mix of generation and reconductoring options were not assessed by Hydro One. As indicated in part a) above, the reconductoring option alone was rejected based on a high level assessment.

e) The reconductoring option was rejected as not being a viable option.

f) The reconductoring option was rejected as not being a viable option and therefore the structures were not reviewed and the need for their replacement was not assessed.

OEB Staff Interrogatory # 2

Reference:

EB-2017-0364 Evidence, Technical Conference on Nextbridge's Motion on Hydro One's Lake Superior Link Application, Transcript Pages 254-255.

MR. ZACHER: Fair enough. The second question I wanted to ask -- I'm not sure if this is for you, but I wanted to ask about the two week outage that Hydro One forecasts taking in August of 2020, and this is to replace the 87 towers in the park. And so the first is how did Hydro One forecast two weeks to get that work done?

MR. KARUNAKARAN: So it was done through consultation with us and SNC-Lavalin and their construction methodologies that we were going to use for the replacement of those towers.

MR. ZACHER: I'm going to betray my ignorance of construction, but 87 towers in two weeks, and you are also upgrading the foundations at the same time; is that right?

MR. KARUNAKARAN: So there is a lot of preparatory work that gets done prior to the actual outage being taken, right. The anchors and so forth for the guy wires and so on are all installed.
The assembly works of the actual structures and so forth are done in off-site fly yards, and so hence I said there's a lot of preparatory work that gets done in advance, right.
Under the actual outage itself, the activities are really to drop the conductor, for lack of better terms, fill the old towers, remove them with the helicopter, install the new towers in location, prep up on the guys and wait them within the existing conductors.

MR. ZACHER: And I think Mr. Henderson had asked questions earlier, and indicated there is no road access. So this is all access by helicopter.

MR. KARUNAKARAN: That is correct.

MR. ZACHER: So is there any sort of reference points or historic examples that you can sort of point to doing this sort of work in the -- over the course of two weeks?

MR. KARUNAKARAN: We've engaged with a number of the actual field construction staff that we would be utilizing for this in determining the schedule, and they have direct experience of -- when we've done projects, say, in Alberta and the like where comparable construction rates have been utilized with respect to production rates.

Interrogatory:

a) Has Hydro One ever constructed 87 230 kV quad (or double circuit) towers of similar design within a span of two weeks in the province of Ontario? If yes, please provide the examples.

b) Will all the required construction work (removal of all existing towers and lines, reinforcement of existing foundations, replacement of existing foundations as required, and erection of new quad towers and stringing of the four transmission circuits and associated communication cables) be completed in the two-week window within the Pukaskwa National Park? Please provide Hydro One's construction and resourcing plans that outline the details of how this aggressive timeline will be met.

c) Has Hydro One taken into account potential weather-related delays for the two-week schedule considering it plans to use helicopters to install the new quad towers? What mitigation plans does Hydro One have to correct for weather-related delays to ensure the overall project remains on schedule?

d) Is the geographical location for the proposed quad towers within the Pukaskwa National Park a major risk factor in Hydro One's ability to meet the in-service timeline? Please explain.

e) If the outage window that Hydro One is proposing to take in August 2020 to install the quad towers within Pukaskwa is missed, when is the next two-week window? What impact would this type of delay have on Hydro One's ability to meet its proposed in-service date in 2021?

f) Have there been any communications between the IESO and Hydro One regarding the proposed two-week outage? If so, has the IESO agreed to Hydro One's proposed two-week outage, in principal? Please provide details of any discussions/communications and copies of all correspondence between Hydro One and the IESO with respect to this matter.

g) What happens if Hydro One's proposed work takes longer than two weeks?

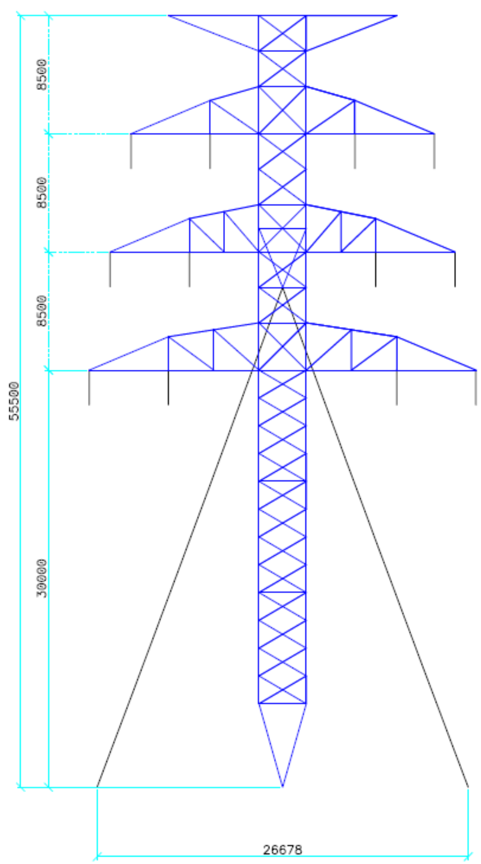
Response:

a) No, Hydro One has not had the need to construct 87, 230 kV quad circuit towers in a span of two weeks. The construction of the LSL Project will be undertaken by SNC-Lavalin through an EPC contract.

b) The self-imposed mandate for the construction within the Pukaskwa National Park ("the Park") is to:

(1) utilize the existing 150' ROW
(2) complete the necessary scope in a single two-week outage, and
(3) minimize the ground disturbances within the Park.

Hydro One has recently determined that the number of foundations requiring replacement is significant enough that it would be preferable to adopt a different design for the new quad structures. Hydro One and SNC's engineering and outage planning teams have now proposed and adopted an alternative design to the Quad Circuit structures which has been discussed with Park staff. The alternative design consists of a single mast structure offset linearly (front or back) from the existing location. These alternate structures require only a single foundation, installed prior to the outage, and will enable the decommissioning of the old foundations, as well as other advantages.



Prior to the outage, work will commence to install all foundations and the four guy anchors for the 87 guyed structures under the still-energized line. All 87 structures will be assembled in three flight yards located on either side of the Park. The guy wire, insulators and travelers will be attached to the assembled structures.

During the two-week outage, the heavy lift helicopters, with a capacity of 24,000 lbs, will be engaged for the installation of the new structures and the decommissioning of the existing structures. For every new structure, two helicopter lifts are required, while for every existing structure removal, one lift is required. Each helicopter crew is capable of achieving on average seven structures per day.

c) Yes, weather delays are accounted for in the production rate. The following contingency mitigations will be implemented:
- The new offset locations allow the existing structures to remain in place until the new structures are fully erected. This provides flexibility to manage the risks, if necessary, by allowing the 15-day outage to be extended, with the ability to recall the EWT line when required during the extension period.
- If an outage extension in 2020 becomes necessary due to unexpected interruptions and is not permitted, the existing transmission line will remain in-service and a second outage would be required in 2021 to complete the Project.

d) No.

e) Hydro One is not currently aware of the next available window. However, Hydro One will work with the IESO to arrange another suitable window to accommodate the required outage to maintain the schedule.

f) Hydro One has met with the IESO and discussed the Lake Superior Link's baseline outage requirements. The IESO has agreed in principle to this request. Additional conversations have occurred with Ontario Power Generation (OPG), Manitoba Hydro Electric Board (MHEB) and Minnesota Power (MP), as these entities' participation will also be instrumental in supporting the outage posture. Hydro One will continue the discussions with the IESO and additional stakeholders on a regular basis in preparation for the two-week outage, currently scheduled for the period of August 10 – 24, 2020.

- Hydro One has submitted the outage request to the IESO (Exhibit I, Tab 1, Schedule 2, Attachment 1).
- Exhibit I, Tab 1, Schedule 2, Attachment 2 reflects the discussions between Hydro One and the IESO regarding this outage.
- Exhibit I, Tab 1, Schedule 2, Attachment 3 is Hydro One's request from the IESO to acknowledge the discussions and the plan for this outage.
- Exhibit I, Tab 1, Schedule 2, Attachment 4 is the IESO's acknowledgement of the discussions and the plan for this outage.

g) Hydro One does not anticipate any need for an outage beyond two weeks. The outage plan has been developed to maximize all possible work (mobilization, yard preparation, foundations, tower assembly, etc.), before starting the outage. This will ensure that the outage time can be optimized to replace the towers. However, should the need arise due to an unexpected delay, please refer to contingency mitigations provided in response to sub-part c) of this interrogatory.

Outage Request Form

Work Request		Planned Outage		Actual Outage		State:	REQUESTED
Start:	Mon Aug 10/20 0800	**Start:**	Mon Aug 10/20 0700	**Start:**		**Outage ID:**	20-00493
End:	Mon Aug 24/20 1600	**End:**	Mon Aug 24/20 1700	**End:**		**Date Created:**	Mon Jul 09/18 0803
Schedule Profile:	Cont	**Weekend I/S:**	N/A	**Org.:**	Hydro One	**Requested By:**	Mike Johnson
Equipment Summary:	W21M, W22M					**Asset Category:**	Power
						Display Type:	Picklist

Outage Type: PO **Work Group:** Contractor Lines TX N **Critical:** Yes **Lob Priority:** Low

New/Changed Equip: Yes **WBS Number:** **PM:** Vladimir Curguz

WP Type: IWP **PC1 Number(s):** **Cancel Cost:** $0.00 **Delay Cost/Hr:** $0.00

Prime Sector:
Sector 4

AOR:
Lakehead

Assoc. Sector(s):

Station:
Marathon TS

Purpose:
SNC Lavalin to dismantle double circuit structures W21M/W22M and install and string W21M/ W22M and new W35M/W36M quadruple structures through Pukaskwa National Park.

Remarks:
** Do not touch this slip unless you talk to Brian Noble or Mitch Dellandrea first, as we need to ensure the timestamp is not affected **
Alain D. Delisle 416-252-5315 x 5515

NPCC Requirement: No **CCOP Process:** ☐ **IESO WAA:** ☐ **IESO SNC:** ☐ **Fdr/Fdr Bkr(s) Involved?:**

Recall:	Recall Comments:
0	None

Assignee OP NMO:

Assignee OP CTRL:

Approver OP NMO: Required

Approver OP CTRL: Required

Included Equipment

Voltage	Station	Included Equipment
230kv	Marathon TS	15-W21M
230kv	Marathon TS	15-W22M
230kv	Wawa TS	14-W21M
230kv	Wawa TS	14-W22M
230kv	Wawa TS	W21M.MAXWA
230kv	Wawa TS	W22M.MAXWA

Historical Actual Date(s)

Actual Outage Start	Actual Outage End	Grid Ready

Tasks

State	Task Desc	Required	Completed	Target Completion	Actual Completion
REQUESTED	Assess Outage Window	X		Wed Jul 08/20 0700	
REQUESTED	Submit to IESO	X	X	Wed Jul 08/20 0700	Mon Jul 09/18 1234
UNCOMMITTED	Controlling Authority Approval			Wed Jul 08/20 0700	
UNCOMMITTED	Load Transfer Settlement Report			Mon Aug 03/20 0700	
UNCOMMITTED	Feeder Transfer Load Study Review			Sat Jul 11/20 0700	
UNCOMMITTED	Long Term Manager Approval	X		Mon Aug 03/20 0700	
UNCOMMITTED	Contingency Plan Analysis & OP Manager Approval	X		Mon Aug 03/20 0700	
UNCOMMITTED	Contingency Plan Included	X		Mon Aug 03/20 0700	
UNCOMMITTED	In-Service Package Review	X		Fri Aug 07/20 0700	
UNCOMMITTED	Companion Transformer Manual Cooling Arrangement			Mon Aug 03/20 0700	
UNCOMMITTED	Defect Equipment Review			Mon Aug 03/20 0700	
UNCOMMITTED	Switching Agent Arrangement	X		Mon Aug 03/20 0700	
UNCOMMITTED	OP IWP Review	X		Fri Aug 07/20 0700	
UNCOMMITTED	Customer Notifications			Mon Aug 03/20 0700	
UNCOMMITTED	Reclose Change Requirement Assessed and Arranged			Mon Aug 03/20 0700	
UNCOMMITTED	NMS Studies			Mon Aug 03/20 0700	
UNCOMMITTED	Review Linked Outages			Mon Aug 03/20 0700	
UNCOMMITTED	Associated Sector(s) Approval			Mon Aug 03/20 0700	
UNCOMMITTED	OP Controller Review & Approval	X		Mon Aug 03/20 0700	
UNCOMMITTED	OP NMO Review & Approval	X		Mon Aug 03/20 0700	
COMMITTED	Delivered to the Control Room	X		Mon Aug 03/20 0700	
CA RECEIVED	Control Room Switching Plan			Sat Aug 08/20 0700	
CA RECEIVED	WP Package	X		Sat Aug 08/20 0700	
CA RECEIVED	Field Switching Orders			Sat Aug 08/20 0700	
CA RECEIVED	Move to Executed State	X			

Outage Request Form

IESO

IESO ID: 1-00090519 **IESO Revision #:** 1 **Has Conflict:** X **FAA:** **Advanced Approval Type:**

Outage Status: Submitted **Last Submitted to IESO:** Mon Jul 09/18 1206 **Advanced Approved By:**

Priority Date: Mon Jul 09/18 1206 **Last Modified by IESO:** Mon Jul 09/18 1206 **Date/Time of Advanced Approval:**

Outage Status Updated By: Hydro One User **Final Approved By:**

Date/Time of Outage Status Update: Mon Jul 09/18 1206 **Date/Time of Final Approval**

IESO Comments:

IESO Errors/Warnings:

Comments

Conflict Rationale

REQUESTED - Long Term Planner - Mon Jul 09/18 1152 - Mitch Dellandrea

Both WxM circuits are required O/S for clearance; it's impossible to do this work without taking both out at the same time.

Correspondence

Contact Group	Ext.	Recipient Name	Primary Contact	Interruption?	Media	Address/Phone No.	Notified By	Date Time

Link(s) for 20-00493

Bundling

Outage ID	Work Request Start	Work Request End	Planned Start	Planned End

Conflict

Outage ID	Work Request Start	Work Request End	Planned Start	Planned End

From: CHAYKA Darin
Sent: Thursday, July 12, 2018 11:24 PM
To: David Devereaux (david.devereaux@ieso.ca); Udayan.Nair@ieso.ca; Fred Ipwanshek (fred.ipwanshek@ieso.ca)
Cc: Rebellon, Pedro (pedro.rebellon@ieso.ca); frank.peng@ieso.ca; NOBLE Brian (brian.noble@HydroOne.com); Ahmed Rashwan (Ahmed.Rashwan@ieso.ca); Adam Tschirhart; Boris Vujasinovic
Subject: Hydro One EW Tie Additions

Dave/Udayan/Fred,

Thanks for taking the time last week, and previous, to discuss Hydro One's proposed double W21/22M outage to facilitate stringing the two new additional EW Tie circuits on the existing structures through the Pukaskwa National Park.

A NOMS Slip #20-00493 with corresponding IESO #1-00090519 has been submitted for the time period August 10th thru August 24th 2020 to reflect the double circuit outage. The outage will be Continuous and for now we'll work with a sliding 15 day Recall.

Although between the major Ontario stakeholders, namely the IESO, OPG and Hydro One, this will be an ongoing discussion involving respective studies, applicable System Limit determinations and production values, among other items leading towards execution, the following will hopefully serve in meeting the IESO requirement for an outage plan two years in advance of the actual outage as per instructions via the OEB hearings.

Below are some notes we discussed, plus some additional default comments we'll continue to discuss moving forward.

- For the planned 2020 outage period, our expectation is to have all Hydro One elements in the Northwest (NW) available. There will be no other major planned work and/or minor outages to impactive elements during the WxM outage.
- Priority will be placed upon this particular EW outage set.
- Any planned NW outages preceding the EW outage will be scheduled to return to service 4 weeks in advance of the August 10th start date to allow for any planned or forced extensions on elements impactive to the overall posture.
- The Northeast will be similarly postured with respect to impactive BES elements deemed supportive of the EW outage, including the Hanmer x Claireville 500 corridor thru Essa.
- We'll need to have further conversations once you've conducted your studies, specifically with OPG, Minnesota, Manitoba and MISO.
- Generation requirements and Limits specifically concerning Bowater, Thunder Bay and the Atikokan unit will also need consideration.

Below is a briefing summary I produced a few months ago and should serve as bulk requirements on our forward conversations.

Background

Hydro One has undertaken a detailed assessment to develop a competitive tender to design, build and operate the proposed East-West Tie transmission line enhancement. The project is a double-circuit

230kV transmission line, spanning approximately 450km from Lakehead TS to Marathon TS to Wawa TS, and is intended to increase the total transfer capability of the Interface from its current 300MW to 450MW by 2021, and further to 650MW by 2024.

The current East-West Tie is comprised of two 230kV circuits from Lakehead to Marathon – this overture would increase the circuit number to a total of four circuits, thereby increasing the transfer capability.

Project History

- In 2012 the Ontario Energy Board released a Request for Proposal (RFP) requesting bids for the development, construction, ownership and operation of a high voltage transmission line to increase the transmission capacity between Lakehead, Marathon and Wawa TS's in Northern Ontario.
- In 2013 NextEra and Enbridge partnered to submit a bid as Upper Canada Transmission (UCT), further referred to in this Briefing as NextBridge, and subsequently selected as the preferred bidder. Both Hydro One and SNC-Lavalin, via its subsidiary Altalink, bid the RFP independently and were deemed runners-up.
- NextBridge proceeded with the preparation and completion of an individual Environmental Assessment (EA) under the Ontario Environmental Assessment Act with the EA currently undergoing governmental review.
- In parallel, NextBridge has applied for Leave to Construct pursuant to Section 92 of the Ontario Energy Board Act.
- Upon receipt of the NextBridge Section 92 application, the Ontario Minister of Energy directed the Independent Electricity System Operator (IESO) to conduct a review of the project needs assessment and cost estimate.

Recent Developments

- In anticipation of an opportunity to submit a competing application for Leave to Construct (LTC), Hydro One and SNC-Lavalin Inc. have formed a partnership to jointly pursue the LTC with a modified corridor routing.
- The key difference between the 2 competing bids, is that the Hydro One/SNC-Lavalin proposed corridor will be shorter in length; 400km as opposed to 450km, with the route reduction to be constructed on, and take advantage of, the existing EW Tie Marathon by Wawa section right-of-way (ROW) through the Pukaskwa National Park. NextBridge's proposal is to route outside of the Park boundary.
- The proposal is also expected to have less environmental impacts and be lower in construction capital costs.

Proposal

- The map below shows the existing NextBridge route around the Pukaskwa National Park.

- The Hydro One/SNC-Lavalin proposal through the Park involves adding the 2 new circuits to modified towers on the existing Marathon by Wawa ROW.
- There is no requirement to widen the existing ROW resulting in significantly less impacts during construction.
- The steel for the tower modifications would be delivered by helicopter and lowered to the ground.
- If required, foundation modifications and guy anchors will be installed by drilling into local rock. These will anchor the tower body to the ground, increasing the towers structural capacity. The machinery is tracked and lightweight ensuring minimal impact to the ground.
- Any material(s) to be removed from the existing towers would be bundled on the ground within the existing ROW and then flown out by helicopter to off-site recycling yards.
- The conductor for the two new circuits will be installed by helicopter.

Proposal Benefits

- A 10% shorter route by utilizing the existing ROW and modifying existing towers in the Pukaskwa National Park, reducing environmental impacts and allowing for significant construction savings.
- Lower design and build cost are achievable through an optimized design solution for the portion of the route outside the Park.
- Lower Operating and maintenance costs by leveraging Hydro One’s existing maintenance and infrastructure programs
- Superior First Nations partnership involving construction and ownership benefits that are shared with communities and modeled after industry leading practices and recent successful transactions.
- Cost certainty through a “not to exceed” construction price to be confirmed in the Hydro One Leave to Construct submission.

Operational Comments

- System Operations has studied the proposed work scope considering a 15 day, No Recall double WxM circuit outage would be required to facilitate the proposal.
- Both circuits out of service constitute an Ontario East West separation.
- This posture would require a very high degree of coordination between H1, the IESO, Ontario Power Generation (OPG), Manitoba Hydro Electric Board (MHEB), Minnesota Power and Light (MPL), the Mid-West Independent System Operator (MISO) and other Stakeholders.

- This scenario would require scheduling other planned Hydro One and Customer work in the Northwest (NW) as the West system is placed in the most secure posture possible while separated from the East, including 115kV generation sources.
- There will be a heavy reliance on generation in the West from an OPG hydraulic perspective. An EW Separation bottles their NW generation, so water levels and flows would need to be managed in advance to meet forecasted BES conditions.
- There will be reliance on the Minnesota and Manitoba Ties and limit constraints are expected to manage transient stability of the NW generators.
- The K21W and K22W may be required to operate free flowing to support a contingency NW. The IESO and MHEB will have to agree to the Phase Shifters set to neutral tap.
- Both MHEB and MPL will have to agree to keep critical elements in service within their system to maintain stability. Both entities have no major work scheduled for 2020 or 2021 that would affect the Interfaces.
- The Hydro One 230V system will have to be fully in service along with all 230/115kV Auto Transformers and all Reactors available.

Operational Summary

Although not normally desirable, at this point, System Operations studies with multiple parameters indicate the proposed plan is achievable. The main issues will be controlling high voltage and OPG's ability to plan and manage hydraulic components, but again, this planned posture would require a very high degree of coordination between H1, the IESO, OPG, MHEB, MPL, MISO and other Stakeholders.

Operational Specifics

The following internal requirements are necessary for the posture to be executed.

<u>Kenora Area</u>

Kenora T1 and the attached Reactor must be available for voltage support and the 115 kV area bounded by Circuits K3D, K6F and the Kenora TS 230/115 kV Autotransformer T1 must also be in service.

In order to maintain support and stability in the Kenora area, production and water management can be split between Whitedog Falls and Caribou Falls.

<u>Dryden Area</u>

Dryden T21 and T22 with Reactors to be available.

<u>Fort Frances Area</u>

Fort T1 and T2 with Reactor to be available.

<u>Moose Lake Area</u>

Mackenzie T3 and the Reactor to be available.

<u>Lakehead Area</u>

Lakehead Auto Transformers T7 and T8, B6M and A5A to be in service.
Lakehead C8 available.
Birch TS 115kV yard fully in service.
Q9B to remain in service in order to have the Thunder Bay GS units available to the system.

Marathon Area

Marathon T11 and T12 with Reactors available for voltage control.
T1M/A5A to be in service.

Algoma Area

Algoma T5 and T6 to remain in service for voltage support to the115kV system.

Thanks again for your time, and please let me know if I've missed or misstated anything in our discussions and/or additional requirements you feel are needed on our path forward. Once you guys have some further information, lets meet again and discuss – I can arrange such when needed. ***As stated above, it is important the IESO acknowledges our plan and timestamp wrt the two year advanced outage plan requirement, so if I could ask that a formal response be sent, it would be greatly appreciated.***

As always, any questions, comments and/or concerns, please reach out.

Talk soon.

Darin

Darin Chayka
Manager, Grid Operations
Operating Planning, System Operations
Ontario Grid Control Centre
Hydro One Networks Inc.
Cell: 705 828 0150
Email: Darin.Chayka@HydroOne.com

From: Darin.Chayka@HydroOne.com [mailto:Darin.Chayka@HydroOne.com]
Sent: September 05, 2018 10:27 AM
To: David Devereaux; Udayan Nair; Fred Ipwanshek
Cc: Pedro Rebellon; Frank Peng; brian.noble@HydroOne.com; Ahmed Rashwan; Adam Tschirhart; Boris Vujasinovic
Subject: RE: Hydro One EW Tie Additions

Dave, Ahmed,

Please see the attached Re: the OEB inquiry into the EW Tie additions (LSL).

Could I ask for a formal response as per the below, in that the IESO acknowledges our plan and that we have collectively had discussions around such. I'll respond to the questions posed to me, but if you wanted to add some color on it/them, I'm more than happy to include your comments.

Bottom line is, I need an acknowledgement from you guys.

Any help is appreciated and call me if there are any issues or concerns.

Thanks.

Darin

Darin Chayka
Manager, Grid Operations
Operating Planning, System Operations
Ontario Grid Control Centre
Hydro One Networks Inc.
Cell: 705 828 0150
Email: Darin.Chayka@HydroOne.com

From: Maia Chase [mailto:maia.chase@ieso.ca]
Sent: Friday, September 07, 2018 3:24 PM
To: CHAYKA Darin
Cc: David Devereaux; Pedro Rebellon
Subject: RE: Hydro One EW Tie Additions - IESO response

*** Exercise caution. This is an EXTERNAL email. DO NOT open attachments or click links from unknown senders or unexpected email. ***

Darin

Here is the IESO response for OEB staff IR 2 (f)

"The IESO has met with Hydro One to discuss the East West tie line addition and the related outage requirement. Hydro One provided the IESO with an overview of the work that will be performed during the outage and informed the IESO that the tentative timeline for the W21M + W22M outage is Aug 2020. The IESO and Hydro One will continue to have these discussions.

Could you please confirm with your Reg Affairs group if they will be providing any of the written correspondence between the IESO and Hydro One on this issue. Also, let me know if you need anything else from us.

Thanks.

Maia

Maia Chase| Senior Advisor - Regulatory Affairs, IESO| Station A, Box 4474, Toronto, Ontario, M5W 4E5| T: 905.403.6906 C: 905.301.6179 |Email: maia.chase@ieso.ca| Web: www.ieso.ca

OEB Staff Interrogatory # 3

Reference:

EB-2017-0364 Evidence, Technical Conference on NextBridge's Motion on Hydro One's Lake Superior Link Application, Transcript Page 258.

UNDERTAKING JT 2.29

Hydro One is to advise what is the point at which field construction work must be postponed to the following year.

Response to JT 2.29

To be able to maintain the December 2021 completion date, construction work must begin no later than January 13, 2020.

Interrogatory:

a) Please provide the date on which field construction would be postponed to following year because of project delays for:
   i. Quadruple tower construction within Pukaskwa National Park, and
   ii. Transmission tower construction outside the Pukaskwa National Park.

Response:

Please refer to Exhibit I, Tab 1, Schedule 2 regarding changes to the construction of towers within Pukaskwa National Park.

a)
   i. The construction of the quad circuit towers within the Park is dependent on the double circuit outage availability window in July and August, 2020. If the construction of the quad towers is delayed and cannot be completed in August 2020, their construction would be pushed to the following year (August 2021)

   ii. Outside the Park, construction would need to commence no later than January 2020 to attain a December 2021 in-service date. After this date, construction would need to be postponed to September 2020 to avoid the environmental constraint season for clearing activities.

OEB Staff Interrogatory # 4

Reference:

EB-2017-0364 Evidence, Hydro One's Application filed on February 15, 2018,
Exhibit F, Tab 1, Schedule 1, Attachment 3, IESO SIA, March 18, 2018, Page 2, Findings, Paragraph 7 and Page 13, section 4.1 Standards and Criteria

Extreme contingencies that result in the loss of the four 230 kV circuits of the East-West Tie such as failure of a quadruple circuit tower can result in separation between the Northwest transmission zone and the rest of the IESO-controlled grid. Following such events, timely system restoration is critical to avoid the risk of supply shortages to the customers in the zone.

The Northwest zone is prone to thunderstorms from April 1st to October 31st. If there is a credible risk of four circuits tripping during those thunderstorms, especially those sharing the same towers, the IESO will need to posture the system to withstand the loss of all four circuits by either reducing the transfer pre-contingency or by arming load rejection. The updated NW SPS 2, as proposed by the connection applicant, does not provide features for detecting extreme contingencies involving more than 2 circuits. Arming for two double-contingencies in preparation for the loss of the four circuits may be acceptable, but could result in unnecessary load disconnection if a double contingency occurs.

In response to OEB staff's question at the Technical Conference on May 17, 2018 found on page 272 regarding restoration times within the Puskaskwa National Park for extreme contingencies; Mr. Young of Hydro One confirmed that there had never been a loss of both circuits in 50 years.

Interrogatory:

a) What has been Hydro One's experience to date with respect to restoration times for the Ontario's North and Northwest?

b) What has been Hydro One's experience with respect to restoration times for the existing East-West Tie line within 50 km of either side of the park for extreme contingency events in the past?

c) What has been the frequency of these events in the past, especially during both thunderstorm and ice storm seasons, impacting
   i. the Ontario's North and Northwest,
   ii. the existing East-West Tie line within 50 km outside the park boundaries.

d) Has Hydro One quantified the dollar impact in the event of an extreme contingency within the park involving, e.g. one day outage involving only minor structural repair, multi day outage involving tower and line repair or replacement?

e) Has Hydro One completed a cost benefit analysis that weighs the cost savings of going through the Puskaskwa National Park versus the cost of an extreme contingency event occurring over the planning horizon that the IESO has used for the Lake Superior Link project?

f) Has Hydro One quantified the dollar impact of potential thunderstorm strikes, ice build ups, wind storms that would trip more than two circuits located on the quadruple towers within Puskaskwa National Park?

g) What is the average yearly frequency of trips for the existing East-West Time line for the past 10 years and how does this compare to the estimated frequency that Hydro One anticipates for section of the proposed line within Puskaskwa National Park?

Response:

a) In the past ten years (July 2008 to July 2018), the North (all the transmission circuits north of Barrie) has experienced on average 19 hours and 8 minutes of outage per 100 km of transmission circuit per year. This is the accumulative outage / restoration time from all causes. For the purpose of this statistic, Hydro One tracks the average outage durations for the combined Northwest and Northeast, therefore the outage (restoration) duration for the Northwest alone is not provided.

b) In the past ten years (July 2008 to July 2018), on average, the two Wawa to Marathon transmission circuits have experienced 17 hours and 40 minutes of outage per 100 km of transmission circuit per year. This is the accumulative outage / restoration time from all causes and for the whole length of the transmission line. Hydro One does not track the outage duration for specific sections (e.g., within 50 km of either side of the park). Of interest, in the context of Question b, during the past ten years:

   i. One tower failed approximately 36 km from Wawa TS (approximately 55 km outside the Park). Both circuits of the transmission line were restored in nine days. The tower failure and the nine-day outage did not cause any interruption to customers. The resources in the Northwest were sufficient to meet the demand while the EWT line was being restored.

ii. There were three equipment failures (conductor, skywire and insulator), each resulting in the outage of one circuit (the second circuit remaining in-service) for two to four days.

iii. There were three sustained outages on one circuit caused by lightning, each lasting for six or seven minutes. There were six momentary outages of one circuit and five momentary outages of two circuits, caused by lightning.

c) In the past ten years (July 2008 to July 2018), the outage frequency from all causes, on average, has been:

i. 2.4 incidents per 100 km per year for all the transmission circuits in the North (Northwest and Northeast combined). On a monthly basis, July has had the highest number of outages.

ii. 0.76 incidents per 100 km per year for the whole length of the two Wawa to Marathon transmission circuits. On a monthly basis, September has had the highest number of outages. According to the records, these outages were not caused by ice storms. As indicated in response b) above, thunderstorms (lightning) have caused 19 momentary and sustained outages in ten years over the whole 336.6 circuit-km of this transmission line.

d) Hydro One has not assessed the cost impact of the above outages.

e) Hydro One has not assessed the cost impact of the extreme contingency in the Park. Extreme events inside and outside the Park, involving the loss of more than two circuits, have similar cost and reliability impact, as accessibility of some of the sections outside the Park are as challenging as the section inside the Park. The section inside the Park is sheltered more than some of the other sections and less prone to damage by storms.

f) Hydro One has not quantified the cost impact of these events. Please also refer to answer to e) above.

g) As indicated in response to c) above, the average yearly frequency of outages of the two Wawa to Marathon transmission circuits in the past 10 years has been 0.76 incidents per 100 km from all causes, including station equipment failures. There were three line equipment failures over the 336.6 circuit-km of the line.

The frequency of the LSL outages as a result of equipment failure within the Park is expected to be less than that of the existing EWT line since the LSL is designed for one-in-one hundred year events. The frequency of the LSL outages caused by lightning within the park is expected to be comparable to that of the existing EWT line and designed to meet the OEB minimum design criteria

OEB Staff Interrogatory # 5

Reference:

EB-2017-0364 Evidence, Hydro One's Application filed on February 15, 2018, Exhibit B, Tab 1, Schedule 1, Page 12

Hydro One requests that a decision on this its application be rendered by October 2018.

Interrogatory:

a) Does Hydro One need a decision by October 2018 to meet its proposed December 2021 in-service date? If not, when does Hydro One need a decision from the OEB? Please explain and identify critical path items in Hydro One's project scheduling and planning.

b) What requirements (approvals, permits etc.) does Hydro One need to satisfy before it can start construction, if Hydro One is selected to build the new East-West Tie line?

Response:

a) In order to meet the December 2021 Hydro One will require:
   - leave to construct approval no later than January, 2019, to initiate procurement activities associated with long lead time items; and
   - EA approval by August, 2019, so that construction can commence.

See the Table below for an updated construction schedule that assumes Leave to Construct approval in January of 2019. Additionally, a scenario analysis is provided at Exhibit I, Tab 1, Schedule 7, to illustrate the impact to the schedule and cost should an EA approval not be received by August of 2019.

The current schedule is provided in the Table below:

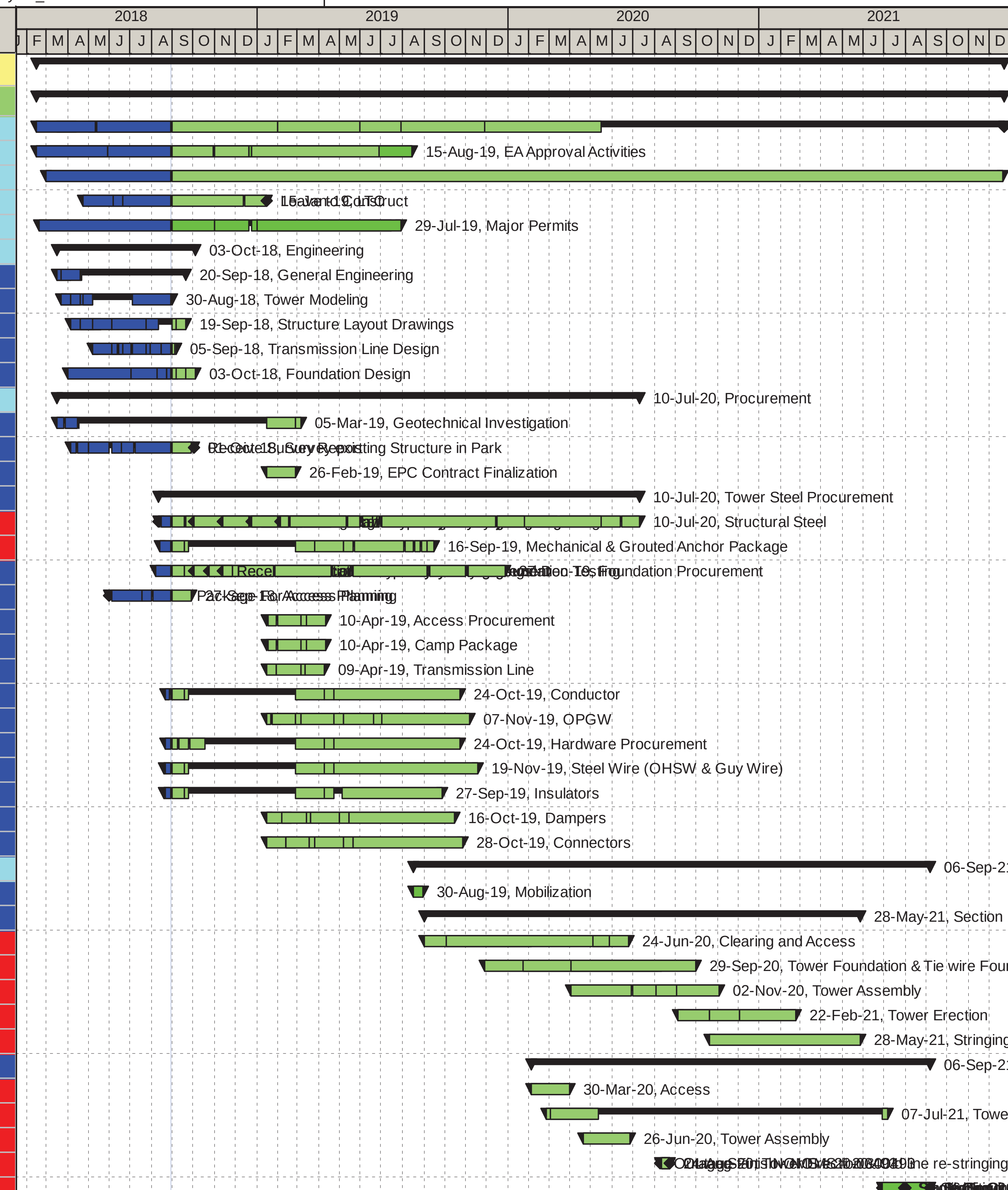
TASK	**START**	**FINISH**
Submit Section 92 Application to OEB		February 2018
Projected Section 92 Approval	February 2018	January 2019
Execute EPC Contract with SNCL		January 2019
Environment Assessment and Consultation		
Obtain EA Approval from MOECC	January 2018	August 2019[1]
Ongoing First Nations & Métis Consultation and Consultation with Stakeholders	February 2018	December 2021
Lines Construction Work		
Real Estate Land Acquisition	March 2018	May 2020
Detailed Engineering	March 2018	Oct 2019
Tender and Award Procurement	January 2019	July 2020
Construction	September 2019	November 2021
Commissioning	September 2021	December 2021
In Service		**December 2021**

[1] Assumption: Declaration Order approved by MECP Minister
Please refer to Attachment 1 for Gantt Chart

b) Final requirements for approvals and permits will be outlined in EA approval documents. Studies and consultation conducted as part of the EA will inform this final determination.

Lake Superior Link Project Schedule - Preferred Route_2018.08.30 R02 | Classic WBS Layout_1 | 20-Sep-18

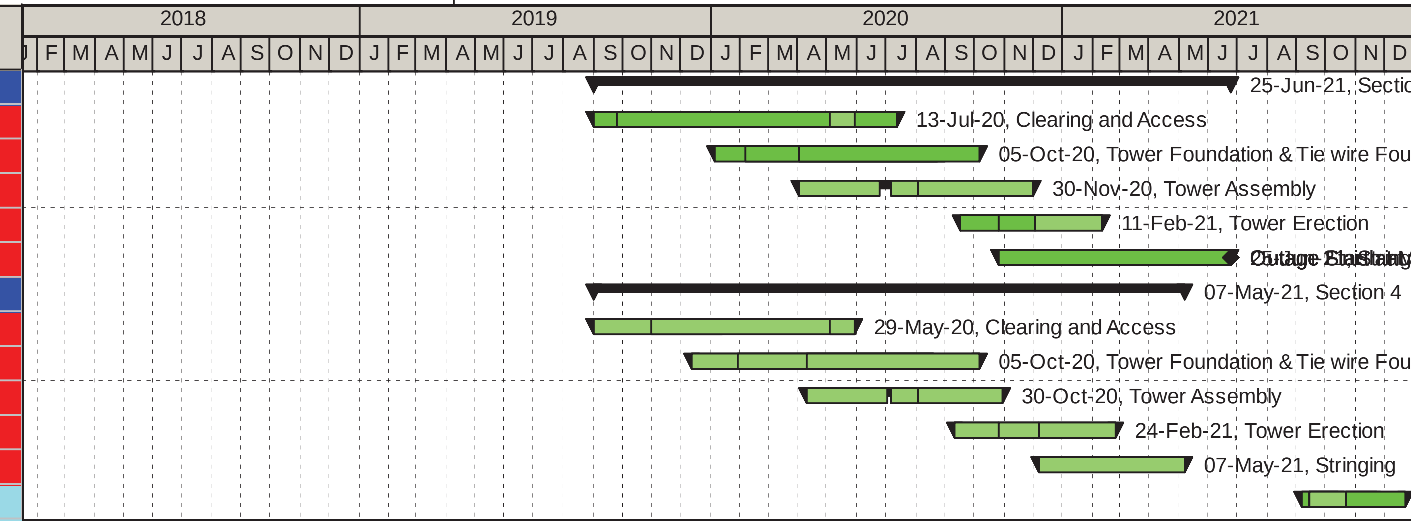
Activity ID	Activity Name	Duration	Start	Finish
	Lake Superior Link Project Schedule - Preferred Route_2018.08.30 R02	1007	14-Feb-18 A	22-Dec-21
	Lake Superior Link Project Schedule	1007	14-Feb-18 A	22-Dec-21
	Project	1007	14-Feb-18 A	22-Dec-21
	EA Approval Activities	392	15-Feb-18 A	15-Aug-19
	Community & Indigenous Relation Activities	994	01-Mar-18 A	20-Dec-21
	LTC	193	23-Apr-18 A	15-Jan-19
	Major Permits	377	19-Feb-18 A	29-Jul-19
	Engineering	144	16-Mar-18 A	03-Oct-18
	General Engineering	135	16-Mar-18 A	20-Sep-18
	Tower Modeling	114	23-Mar-18 A	30-Aug-18
	Structure Layout Drawings	119	06-Apr-18 A	19-Sep-18
	Transmission Line Design	87	08-May-18 A	05-Sep-18
	Foundation Design	133	02-Apr-18 A	03-Oct-18
	Procurement	607	16-Mar-18 A	10-Jul-20
	Geotechnical Investigation	254	16-Mar-18 A	05-Mar-19
	Survey existing Structure in Park	126	06-Apr-18 A	01-Oct-18
	EPC Contract Finalization	30	16-Jan-19	26-Feb-19
	Tower Steel Procurement	502	10-Aug-18 A	10-Jul-20
	Structural Steel	502	10-Aug-18 A	10-Jul-20
	Mechanical & Grouted Anchor Package	287	13-Aug-18 A	16-Sep-19
	Foundation Procurement	366	06-Aug-18 A	27-Dec-19
	Access Planning	85	01-Jun-18 A	27-Sep-18
	Access Procurement	61	16-Jan-19	10-Apr-19
	Camp Package	61	16-Jan-19	10-Apr-19
	Transmission Line	60	16-Jan-19	09-Apr-19
	Conductor	310	20-Aug-18 A	24-Oct-19
	OPGW	212	16-Jan-19	07-Nov-19
	Hardware Procurement	308	22-Aug-18 A	24-Oct-19
	Steel Wire (OHSW & Guy Wire)	328	20-Aug-18 A	19-Nov-19
	Insulators	291	20-Aug-18 A	27-Sep-19
	Dampers	196	16-Jan-19	16-Oct-19
	Connectors	204	16-Jan-19	28-Oct-19
	Construction	537	16-Aug-19	06-Sep-21
	Mobilization	11	16-Aug-19	30-Aug-19
	Section 1	455	02-Sep-19	28-May-21
	Clearing and Access	213	02-Sep-19	24-Jun-20
	Tower Foundation & Tie wire Foundation	211	28-Nov-19	29-Sep-20
	Tower Assembly	153	02-Apr-20	02-Nov-20
	Tower Erection	114	04-Sep-20	22-Feb-21
	Stringing	150	21-Oct-20	28-May-21
	Section 2	406	05-Feb-20	06-Sep-21
	Access	39	05-Feb-20	30-Mar-20
	Tower Foundation & Tie wire Foundation	348	26-Feb-20	07-Jul-21
	Tower Assembly	50	20-Apr-20	26-Jun-20
	Tower Erection & Old line re-stringing	11	10-Aug-20	24-Aug-20
	New Lines Stringing	51	28-Jun-21	06-Sep-21



Remaining Level of Effort | Actual Work | Critical Remaining Work | Summary
Actual Level of Effort | Remaining Work | Milestone

TASK filter: All Activities

Activity ID	Activity Name	Duration	Start	Finish
	Section 3	475	02-Sep-19	25-Jun-21
	Clearing and Access	226	02-Sep-19	13-Jul-20
	Tower Foundation & Tie wire Foundation	196	06-Jan-20	05-Oct-20
	Tower Assembly	173	02-Apr-20	30-Nov-20
	Tower Erection	98	17-Sep-20	11-Feb-21
	Stringing	166	27-Oct-20	25-Jun-21
	Section 4	440	02-Sep-19	07-May-21
	Clearing and Access	195	02-Sep-19	29-May-20
	Tower Foundation & Tie wire Foundation	204	13-Dec-19	05-Oct-20
	Tower Assembly	147	09-Apr-20	30-Oct-20
	Tower Erection	111	11-Sep-20	24-Feb-21
	Stringing	101	08-Dec-20	07-May-21
	Commissioning & Close Out	77	07-Sep-21	22-Dec-21



Remaining Level of Effort | Actual Work | Critical Remaining Work | Summary
Actual Level of Effort | Remaining Work | Milestone

TASK filter: All Activities

OEB Staff Interrogatory # 6

Reference:

EB-2017-0364 Evidence, Hydro One's Application filed on February 15, 2018, Exhibit B, Tab 11, Schedule 1, Page 1

Hydro One projects an in-service date of December 2021.

Interrogatory:

a) Hydro One is projecting that it will complete construction of its proposal in 38 months; from OEB approval to the in-service date.
   i. Please provide a list of transmission projects that Hydro One has completed within a comparable timeline in the past 10 years.

b) If approved, will Hydro One require internal resources to be re-allocated to ensure that it meets the proposed project timeline?

c) If Hydro One schedule falls behind, what corrective measures will Hydro One take to bring the project back on track?

Response:

a) A list of transmission projects that Hydro One has completed within a comparable timeline in the last 10 years is provided in Attachment 1. In this list, Hydro One has also identified Projects that have been subject to OEB leave to construct approval.

b) Due to the EPC contract with SNC-Lavalin, limited internal resources will need to be reallocated to ensure that Hydro One meets the proposed project timeline.

c) Hydro One will monitor the SNC-Lavalin contract through regular project updates against defined reporting requirements. Standard project and contract management techniques will be used to bring the project back on track if the schedule falls behind such as looking at utilization of additional resources, overtime, etc. Also note that within the EPC contract SNC-Lavalin has risk exposure of liquidated damages should their substantial completion date not be met, and are therefore incentivized to deliver the project on schedule.

Transmission Capital Projects In Service with Execution Duration between 30 to 45 months

(excludes Tx Projects related to Distributed Generation work)

Driver (Tx)	AR	Project Description	Execution Duration (Months)	In-Service Date
N.T.C.2.11	21376	Northgate Minerals- 7km Line Transfer to Hydro One	30	10/7/2013
N.T.C.2.12	21787	X3H - Connect Kingston Solar Project	30	9/3/2015
N.T.C.1.43	23390	Richview TS T5/T6; Component Replacement	30	7/13/2017
N.T.C.1.41	23243	Brant TS T1/T2	31	11/18/2016
N.T.C.2.03	21518	Reactors at Marathon TS	31	5/14/2015
N.T.C.2.11	17037	Long Lac T1: Replace End-of-Life 115-44 kV Transfo	31	10/31/2011
N.T.C.1.15	18371	H2JK & K6J - Replace HV UG Cables	31	12/14/2014
N.T.C.2.21	21610	Main TS HV Breakers	31	4/30/2014
N.T.C.1.41	23247	Cumberland TS T3/T4	31	12/16/2016
N.T.C.1.08	22319	OverBrook TS, EOL Transformer Asset Replacement	31	12/15/2017
N.T.C.1.42	23252	Alliston TS T3/T4; PCT & Component Replacement	31	12/16/2016
N.T.C.1.44	23170	Frontenac TS EOL Stat Reinvstmt proj	31	3/26/2018
N.T.C.1.21	17577	Burlington TS 230kV Drainage Improvements	32	12/14/2012
N.T.C.1.43	23442	Dufferin TS T2/T4; Component Replacement	32	12/21/2017
N.T.C.2.03	18505	Hanmer TS - Install Additional 149 MVAr Shunt Cap	32	10/12/2012
N.T.C.2.12	22600	Lennox TS 500kV Bus -Connect Napanee GS	32	3/10/2018
N.T.C.1.19	21470	Beck#2-NYPA - Tie-Line Protection Replacement	33	12/7/2014
N.T.C.2.12	21286	Q6S:Connect the Amherst Island Wind Tx FIT Project	33	5/2/2018
N.T.C.1.17	18001	Replace Failed Beck R76 400 MVA 230 kV Reg	33	12/31/2012
N.T.C.1.08	20661	Dundas TS, EOL Asset Replacement Project	33	12/21/2015
N.T.C.1.08	21817	Cooksville TS Transformer Replacement Project	33	9/30/2015
N.T.C.2.03	18239	Kapuskasing TS - Install 21.6 MVAr Cap Bank	33	8/25/2014
N.T.C.1.12	23606	C25H # Line Refurbishment	34	4/14/2016
N.T.C.2.21	18309	Erindale TS - T5/T6 Rod Gaps Replacement & HV/LV S	34	3/1/2012
N.T.C.1.08	20663	Gerrard TS, EOL T1,T2,T3,T4 Asset Replacement	35	8/14/2016
N.T.C.1.25	19469	Microwave Replacement - Phase 3 drawings	35	11/28/2012
N.T.C.1.14	20883	Hwy 407 East Ext.-Reloc at Leskard Rd-Recoverable	35	4/29/2016
N.T.C.1.42	23476	CMS Station Service and Yard Supply Replacement	35	12/15/2017
N.T.C.1.08	22298	Wiltshire TS - Tx Station Re-investment Project	35	11/29/2016
N.T.C.1.44	23246	Longueuil TS T3/T4	36	4/26/2017
N.T.C.1.08	20605	Pickering 'A' SS - Station Re-Investment	36	3/28/2014
N.T.C.1.08	22420	Strathroy TS # EOL Station Refurbishment	36	12/15/2017
N.T.C.1.08	20593	Timmins TS EOL 115kV Asset Replacement Project	36	9/30/2016
N.T.C.1.08	20576	Wallaceburg: Reconfigure TS to Address Failed Xfmr	36	5/30/2014
N.T.C.1.08	21670	Goderich TS - Station Reconfiguration	37	12/1/2017
N.T.C.1.19	17759	Moses GS-St. Lawrence Line Differential Protection	38	3/15/2013
N.T.C.1.12	23392	Line Refurbishment - C22J/C24Z/C21J/C23Z	38	12/20/2017
N.T.C.2.12	21516	Abitibi Bowater CTS - G6 Generator Connection	39	5/3/2017
N.T.C.2.21	21574	Basin TS HV Reactors	39	12/23/2014
N.T.C.2.03	18390	Kirkland Lake TS - Install SVC	39	10/17/2011
N.T.C.2.12	17418	Lower Mattagami Generation Connection	40	11/5/2014
N.T.C.1.08	20600	Burlington TS: ABCB Replacement Project	41	11/18/2016
N.T.C.1.08	20537	Hanmer TS - Transmission Station Re-Inve	41	7/18/2014
N.T.C.3.08	22265	Extreme Space Weather Prepardness Phase II	41	11/11/2015
N.T.C.1.08	18589	Pinard TS: Reconfig 115 kV, Build Swyrd, Demerge	41	7/4/2014
N.T.C.2.21	20706	Allanburg TS: Uprate Short Circuit Capability	42	11/14/2014
N.T.C.3.08	21295	Extreme Space Weather Prepardness	42	12/31/2014

N.T.C.1.17	22215	Manitouwadge T1- Replace EOL Transformers	42	7/12/2016
N.T.C.2.21	17425	Mitigate Reliability Problems of HV Shunt Capacit	43	7/16/2012
N.T.C.1.40	23241	Buchanan TS BULK	44	12/15/2017
N.T.C.2.02	18836	Meadowvale TS Cap Banks Adding 2 New	45	3/26/2010
Recent Projects Subject to Leave to Construct				
N.T.C.2.02	17259	Leaside TS x Bridgman TS: Build new 115kV circuit (Midtown)	62	12/1/2016
N.T.C.2.02	17298	Woodstock Area Transmssion Reinforcement (WATR) (Woodstock Tx Reinforcement)	42	4/30/2011
N.T.C.2.02	17052	Hurontario Station and Transmission Line Reinforc (West Brampton)	36	2/11/2010
N.T.C.2.02	17389	Guelph Area Transmission Refurbishment (Guelph)	33	11/28/2016
N.T.C.2.03	18839	New 500 kV Bruce to Milton Double Circuit Line (BxM H1N S99)	33	12/1/2012
N.T.C.2.11	20831	Lower Mattagami Construction Power (Lower Mattagami)	25	12/1/2012
N.T.C.2.03	20518	Lambton to Longwood Transmission Upgrade (Lambton to Longwood)	22	9/25/2014
N.T.C.2.11	18805	Commerce Way TS:Build new TS (Woodstock East)	21	12/19/2012
N.T.C.2.12	21285	Niagara Region Wind Farm FIT project (NRWC)	18	9/29/2016

List of Appropriation Requests In-Service
(T.C. SP 203/224)

Driver (Tx)	AR	AR Description	Execution Duration (Months)	Fcst/Actual EMPP	In-Service Date	In-Service Year
N.T.C.1.25	17248	Interface Protections to Fiber network # Ottawa	114	1/1/2008	6/15/2017	2017
N.T.C.2.21	17517	Lambton TS: Station Service Upgrade	106	11/1/2009	8/26/2018	2018
N.T.C.2.03	17128	Nanticoke TS: Add 500 kV, 350 MVAr SVC	85	7/7/2009	9/30/2016	2016
N.T.C.1.20	20265	Bruce A & B Station Service Upgrades	79	3/15/2010	9/30/2016	2016
N.T.C.1.25	18679	DC signalling replacement in Hamilton area	82	1/1/2006	10/19/2012	2012
N.T.C.2.19	21253	Havelock TS M3 ID12950-Tx Kawartha Biogas	76	2/23/2011	6/30/2017	2017
N.T.C.2.02	17259	Leaside TS x Bridgman TS: Build new 115kV circuit	81	9/30/2010	7/16/2017	2017
N.T.C.2.19	21797	Coboconk DS F2 ID16140 Tx Norland Hydropower	64	11/30/2011	4/3/2017	2017
N.T.C.2.19	21228	Dobbin TS M4 ID11650-TX London Street GS-Expansion	60	7/20/2011	7/18/2016	2016
N.T.C.2.11	20731	Hinchey TS: Add switching to idle trfr windings	68	2/28/2011	10/28/2016	2016
N.T.C.2.19	21568	Kent TS-M15-ID274-Tx-PV mitigation	62	8/30/2012	11/5/2017	2017
N.T.C.1.18	21292	Lakehead TS # C8 Synchronous Condenser Refurb	64	8/19/2011	12/20/2015	2015
N.T.C.2.02	20171	Manby TS: Uprate 115kV Switchyard	66	8/31/2011	2/25/2017	2017
N.T.C.2.19	21579	Muskoka TS M7 ID14110 -Tx Bracebridge Falls	67	9/12/2011	3/31/2017	2017
N.T.C.2.19	21606	Muskoka TS M7 ID14120 -Tx Wilson#s Falls Gen	66	9/24/2011	3/31/2017	2017
N.T.C.1.24	18566	PLC Replacement in Ottawa/Eastern Region	69	7/30/2004	4/30/2010	2010
N.T.C.2.19	21114	Wilson TS M12 ID12810 - Tx Ballyduff Wind Farm	71	11/4/2011	9/25/2017	2017
N.T.C.2.03	17136	BSPS Modifications for Bruce for 2009	54	5/1/2008	11/11/2012	2012
N.T.C.2.02	17811	Burlington TS: 115KV Switchyard Reconstruction	59	1/15/2008	12/19/2012	2012
N.T.C.1.08	20139	Carlaw A6-A7 Metalclad Swgr	53	6/25/2013	12/6/2017	2017
N.T.C.2.03	20112	Clarington TS: New 500/230kV station	51	1/15/2014	4/25/2018	2018
N.T.C.2.19	22543	Duart TS - M5 - Tx - DG 487 Distance Limitation	53	11/15/2012	4/15/2017	2017
N.T.C.1.17	21851	Dymond TS T3&T4 Transformer Replacement Prog.	59	1/21/2013	12/15/2017	2017
N.T.C.2.02	17389	Guelph Area Transmission Refurbishment	54	2/26/2014	8/27/2018	2018
N.T.C.2.11	19297	Kirkland Lake TS - Add 44kV Feeder Position	57	8/27/2012	5/16/2017	2017
N.T.C.1.17	21850	Lakehead TS T7&T8 Transformer Replacement Prog.	53	3/29/2013	8/18/2017	2017
N.T.C.2.02	20556	Leaside TS - 115kV Switchyard Uprate	49	12/1/2010	12/31/2014	2014
N.T.C.1.08	20256	Merivale GIS 'ITE' Bus Replacement	49	3/31/2011	4/24/2015	2015
N.T.C.1.08	17185	Orangeville TS - Transmission Station Re-Inve	48	12/6/2010	12/6/2014	2014
N.T.C.2.19	22397	Orillia TS M1 ID20150-TX 555 Memorial Ave	50	10/15/2012	12/8/2016	2016
N.T.C.2.19	21104	P&C W-TC219- DG Connection Advancement for $107.7M	58	12/27/2010	10/30/2015	2015
N.T.C.1.29	19917	Physical Security	56	5/2/2011	12/18/2015	2015
N.T.C.1.08	21257	Pickering 'A' T3L7 & T2L8 Brk Remov, Decommiss Air	56	4/22/2013	12/15/2017	2017
N.T.C.1.25	22295	PMR Base Station Alarm System	58	3/1/2013	12/15/2017	2017
N.T.C.1.10	22810	Scarboro TS ISCR	55	6/1/2013	12/22/2017	2017
N.T.C.2.19	21015	TC219 - DG Connection Advancement for $107.7M	51	12/31/2012	3/23/2017	2017
N.T.C.1.08	20944	Trafalgar T14 750 MVA Autotransformer Re-Invest	53	7/1/2011	12/11/2015	2015
N.T.C.1.19	20322	Underfrequency Load Shedding Upgrades	50	12/2/2011	1/22/2016	2016
N.T.C.2.02	17298	Woodstock Area Transmssion Reinforcement (WATR)	53	10/18/2007	3/26/2012	2012
N.T.C.1.12	21986	H24C - Line Refurbishment	50	6/23/2013	8/28/2017	2017
N.T.C.2.11	17320	Terry Fox MTS: Build New 230kV Line Tap	58	2/4/2013	12/15/2017	2017
N.T.C.1.19	17013	2004 Monitoring: Bruce GS Add SER and Decommissio	46	1/11/2010	10/30/2013	2013
N.T.C.1.08	18538	2005-06 Nanticoke TS TSI & ABCB Repl. Prog.	47	6/1/2007	4/28/2011	2011
N.T.C.2.21	20706	Allanburg TS: Uprate Short Circuit Capability	42	5/26/2011	11/14/2014	2014
N.T.C.2.21	21574	Basin TS HV Reactors	39	10/1/2011	12/23/2014	2014
N.T.C.1.19	20230	Bridgman TS Relay Building & Equipment Replacement	48	1/1/2011	12/19/2014	2014
N.T.C.1.40	23241	Buchanan TS BULK	44	5/1/2014	12/15/2017	2017
N.T.C.1.08	20600	Burlington TS: ABCB Replacement Project	41	7/5/2013	11/18/2016	2016
N.T.C.1.42	23245	Buttonville TS T3/T4; PCT & Component Replacement	46	7/29/2013	5/26/2017	2017
N.T.C.2.19	21308	Dryden TS-M3 ID 12070 TX- Wainwright Solar Park	38	6/26/2011	8/22/2014	2014
N.T.C.3.08	21295	Extreme Space Weather Prepardness	42	6/29/2011	12/31/2014	2014
N.T.C.3.08	22265	Extreme Space Weather Prepardness Phase II	41	6/7/2012	11/11/2015	2015
N.T.C.2.19	21432	Fergus TS M6 ID12820-Tx Bellwood Windfarm	39	7/6/2011	10/15/2014	2014
N.T.C.2.19	20040	Funds Transferred from DC203	38	12/16/2009	2/13/2013	2013

Driver (Tx)	AR	AR Description	Execution Duration (Months)	Fcst/Actual EMPP	In-Service Date	In-Service Year
N.T.C.1.08	21670	Goderich TS - Station Reconfiguration	37	10/20/2014	12/1/2017	2017
N.T.C.1.08	20537	Hanmer TS - Transmission Station Re-Inve	41	2/15/2011	7/18/2014	2014
N.T.C.2.19	22171	Hanover TS-H1E-ID17750-Tx-East Durham Wind Energy	39	4/11/2012	7/24/2015	2015
N.T.C.2.19	21112	Hearst TS-M2-ID 12080- Tx- Mattawishkwia Solar Par	41	3/15/2011	7/30/2014	2014
N.T.C.2.02	17052	Hurontario Station and Transmission Line Reinforc	37	2/14/2007	3/8/2010	2010
N.T.C.2.19	21276	Kapuskasing TS M4 ID12020 Kap Solar TX	39	6/1/2011	8/15/2014	2014
N.T.C.2.19	22915	Kingsville TS M6 ID 21860 TX Leamington Pollution	43	8/15/2013	3/16/2017	2017
N.T.C.2.03	18390	Kirkland Lake TS - Install SVC	39	7/1/2008	10/17/2011	2011
N.T.C.2.19	21381	Kirkland Lake TS M62 ID12890 - Tx Wendigo Waterpo	44	8/10/2011	4/1/2015	2015
N.T.C.1.18	22094	Large Diesel Generator Upgrade Project	46	2/21/2012	12/8/2015	2015
N.T.C.2.19	22250	Longueuil TS-M24-ID964 & 965-Tx PV mitigation	40	6/1/2012	9/30/2015	2015
N.T.C.1.17	22215	Manitouwadge T1- Replace EOL Transformers	42	1/1/2013	7/12/2016	2016
N.T.C.2.02	18836	Meadowvale TS Cap Banks Adding 2 New	45	7/12/2006	3/26/2010	2010
N.T.C.2.19	21002	Midhurst TS M4 ID12200-Tx RE Midhurst 4	37	1/14/2011	2/12/2014	2014
N.T.C.2.21	17425	Mitigate Reliability Problems of HV Shunt Capacit	43	12/22/2008	7/16/2012	2012
N.T.C.2.21	20946	Modify Lennox X21X22 LEO Protection	46	2/7/2012	12/16/2015	2015
N.T.C.2.19	21205	Morrisburg TS M23 ID12570-Tx Edwardsburgh 1	42	2/14/2011	8/7/2014	2014
N.T.C.1.19	17759	Moses GS-St. Lawrence Line Differential Protection	38	1/1/2010	3/15/2013	2013
N.T.C.2.19	22923	Norfolk TS M5 ID18230-TX UDI Port Ryerse Wind Farm	38	9/9/2013	11/18/2016	2016
N.T.C.2.19	21238	Orangeville TS M4 ID12830-Tx Whittington Wind Farm	42	5/1/2011	10/22/2014	2014
N.T.C.2.19	21242	Orillia TS M2 ID11790-Tx Wasdell Falls Waterpower	46	6/29/2011	5/7/2015	2015
N.T.C.2.19	23311	Picton TS M5 ID24780 Tx-AGRIS Solar Garden 11	44	8/8/2012	4/14/2016	2016
N.T.C.1.08	18589	Pinard TS: Reconfig 115 kV, Build Swyrd, Demerge	41	1/20/2011	7/4/2014	2014
N.T.C.2.19	22137	Port Hope TS DESN2 M1 ID16040 - Penn Energy Van-TX	42	5/24/2012	11/20/2015	2015
N.T.C.2.19	21211	Ramore TS M5 ID12050-Tx Ramore Solar Park	40	3/9/2011	7/22/2014	2014
N.T.C.2.19	21766	Stewartville TS M3 ID14950-Tx LowerPlant Rehabilit	41	10/10/2011	3/2/2015	2015
N.T.C.2.19	22330	Strathroy TS-M1-ID 17760-Tx-Napier Wind Farm	40	8/9/2012	12/2/2015	2015
N.T.C.1.08	20593	Timmins TS EOL 115kV Asset Replacement Project	36	9/30/2013	9/30/2016	2016
N.T.C.2.19	21399	Trout Lake TS- M7- ID#11850- Tx- Okikendawt Hydro	48	6/10/2011	6/5/2015	2015
N.T.C.1.08	20576	Wallaceburg: Reconfigure TS to Address Failed Xfmr	36	5/15/2011	5/30/2014	2014
N.T.C.2.19	20354	Wallace TS M4 ID549 Greenview Power TX	40	9/20/2011	2/2/2015	2015
N.T.C.2.19	21973	Wilson TS M15 ID10250 Tx - Clarington #1	38	1/13/2012	3/26/2015	2015
N.T.C.2.12	21516	Abitibi Bowater CTS - G6 Generator Connection	39	2/12/2014	5/3/2017	2017
N.T.C.1.12	23392	Line Refurbishment - C22J/C24Z/C21J/C23Z	38	10/8/2014	12/20/2017	2017
N.T.C.2.12	17418	Lower Mattagami Generation Connection	40	7/4/2011	11/5/2014	2014
N.T.C.1.18	18234	2009 Resistive Load Center Purchase	28	7/9/2009	11/14/2011	2011
N.T.C.1.45	23781	A5A M2D W6CS 115kV Line Protection NERC Upgrades	27	7/7/2015	9/25/2017	2017
N.T.C.1.42	23252	Alliston TS T3/T4; PCT & Component Replacement	31	5/1/2014	12/16/2016	2016
N.T.C.1.44	23224	Almonte TS T3/T4	27	5/1/2014	7/22/2016	2016
N.T.C.2.11	23381	Aylmer TS: Add 2 Breakers - ETPC & H1Dx	26	2/27/2015	5/15/2017	2017
N.T.C.1.19	21470	Beck#2-NYPA - Tie-Line Protection Replacement	33	3/7/2012	12/7/2014	2014
N.T.C.2.21	19998	Belleville TS: Replace Neutral Reactors	27	8/1/2011	10/25/2013	2013
N.T.C.1.41	23243	Brant TS T1/T2	31	5/1/2014	11/18/2016	2016
N.T.C.2.19	21693	Brown Hill TS- M11- ID15920- Tx- EarthLight LP	29	5/9/2013	10/16/2015	2015
N.T.C.2.19	21740	Brown Hill TS M4 ID 15950 - Tx BeamLight LP	28	5/3/2013	8/25/2015	2015
N.T.C.2.03	23632	Bruce A TS & Longwood TS: Reactor Switching Scheme	29	3/22/2016	8/21/2018	2018
N.T.C.2.02	17215	Build two 3-km circuits from Hurontario SS to Jim	29	10/3/2007	3/8/2010	2010
N.T.C.1.21	17577	Burlington TS 230kV Drainage Improvements	32	4/26/2010	12/14/2012	2012
N.T.C.2.19	21726	Chesterville TS M2 ID15990 Tx - MightySolar	25	6/14/2012	7/3/2014	2014
N.T.C.1.17	22436	Claireville 750 MVA Autotranf Replacement - T15	25	11/15/2012	12/8/2014	2014
N.T.C.1.17	21294	Claireville 750 MVA Autotransf Replacement - T14	29	5/18/2012	10/24/2014	2014
N.T.C.1.42	23476	CMS Station Service and Yard Supply Replacement	35	1/8/2015	12/15/2017	2017
N.T.C.2.19	23211	Commerce WayTS M1 ID22500 TX Gunn's Hill Wind Farm	28	7/5/2014	11/11/2016	2016
N.T.C.1.08	21817	Cooksville TS Transformer Replacement Project	33	12/19/2012	9/30/2015	2015
N.T.C.2.19	20819	Crosby TS M2 ID11950-TX Rideau Lakes	29	12/27/2010	5/14/2013	2013
N.T.C.2.19	21046	Crosby TS M2 ID11970-TX Northland Solar Crosby	29	12/6/2010	5/7/2013	2013
N.T.C.2.19	21434	Crowland TS M1 ID12590-Tx Axio Welland Ridge Rd	34	9/29/2011	7/28/2014	2014
N.T.C.2.19	20752	Crystal Falls TS M2 Crystal Falls Conn. ID-10 TX	28	10/15/2010	2/22/2013	2013

Driver (Tx)	AR	AR Description	Execution Duration (Months)	Fcst/Actual EMPP	In-Service Date	In-Service Year
N.T.C.1.41	23247	Cumberland TS T3/T4	31	5/1/2014	12/16/2016	2016
N.T.C.2.03	17859	Detweiler TS: Add 230 kV, 350 MVAr SVC	30	6/18/2009	12/2/2011	2011
N.T.C.2.19	22597	Douglas Point TS-M1-ID20940-Tx-Meyer Wind Farm	31	1/16/2013	8/3/2015	2015
N.T.C.2.19	22462	Douglas Point TS-M6-ID20530-Quixote One WE -Tx	32	11/13/2012	7/16/2015	2015
N.T.C.1.43	23442	Dufferin TS T2/T4; Component Replacement	32	5/1/2015	12/21/2017	2017
N.T.C.1.42	23242	Ellesmere TS T3/T4; PCT & Component Replacement	27	5/1/2014	7/15/2016	2016
N.T.C.2.19	21288	Elliot Lake TS M3 - ID 12310 Pecors Power TX	29	6/30/2011	12/1/2013	2013
N.T.C.2.21	18309	Erindale TS - T5/T6 Rod Gaps Replacement & HV/LV S	34	5/4/2009	3/1/2012	2012
N.T.C.1.45	22329	Espanola TS EOL Stat Reinvstmt proj	27	2/9/2015	5/19/2017	2017
N.T.C.1.44	23170	Frontenac TS EOL Stat Reinvstmt proj	31	8/18/2015	3/26/2018	2018
N.T.C.2.19	21220	Gardiner TS_M14_ID12,600_2225054 Ontario Odessa_Tx	32	3/21/2011	11/21/2013	2013
N.T.C.2.19	21222	Gardiner TS_M14_ID12,620_2225055 ON Hwy2 South_Tx	31	4/1/2011	11/11/2013	2013
N.T.C.2.19	21193	Gardiner TS_M3_ID12,580_2225128 ON Unity Road_Tx	33	3/15/2011	12/20/2013	2013
N.T.C.1.08	20663	Gerrard TS, EOL T1,T2,T3,T4 Asset Replacement	35	9/17/2013	8/14/2016	2016
N.T.C.2.04	21296	Goderich TS - Station Upgrade	26	5/12/2011	6/28/2013	2013
N.T.C.1.43	23238	Goreway TS T4/T5/T6; T4, PCT & Component Replaceme	25	5/1/2014	6/17/2016	2016
N.T.C.2.03	18505	Hanmer TS - Install Additional 149 MVAr Shunt Cap	32	2/11/2010	10/12/2012	2012
N.T.C.2.02	18260	Hearn TS: Rebuild Hearn SS	28	9/30/2011	1/31/2014	2014
N.T.C.3.08	23835	HMI Replacement	28	11/10/2015	2/28/2018	2018
N.T.C.2.02	22279	Holland TS - Add Breakers and Re-terminate Lines	25	11/30/2015	12/15/2017	2017
N.T.C.2.19	21540	Ingersoll TS M45 Tx-ID14340 RE Breen 2	32	6/14/2011	2/7/2014	2014
N.T.C.2.03	18239	Kapuskasing TS - Install 21.6 MVAr Cap Bank	33	11/3/2011	8/25/2014	2014
N.T.C.2.19	21537	Kapuskasing TS M3 - ID 11740 - Old Woman Falls TX	27	7/6/2011	9/20/2013	2013
N.T.C.2.19	21539	Kapuskasing TS M3 -ID 11750 - White Otter Falls TX	24	7/6/2011	7/5/2013	2013
N.T.C.2.19	23139	Kingsville TS M4 ID22910-Tx Mucci Farms	24	8/19/2014	8/26/2016	2016
N.T.C.2.19	23142	Kingsville TS M4 ID22920-Tx Agriville Farms	32	8/19/2014	4/28/2017	2017
N.T.C.2.11	17503	Leamington TS: New 230/27.6 kV DESN and Line cone	25	5/10/2016	5/26/2018	2018
N.T.C.1.44	23459	Lennox TS BULK:OPG Sync Breaker Replacement Coord	25	12/15/2015	1/11/2018	2018
N.T.C.2.19	21888	Lindsay TS M6 ID16150 Tx- Perpetual Cleanpower	33	1/27/2012	10/23/2014	2014
N.T.C.2.19	22494	Lindsay TS M7 ID20780 Tx Balsam Lake Green Energy	27	11/23/2012	2/23/2015	2015
N.T.C.2.19	21464	Lindsay TS M8 ID12850 Tx Skypower Glenarm LP	27	7/24/2012	10/20/2014	2014
N.T.C.2.11	17037	Long Lac T1: Replace End-of-Life 115-44 kV Transfo	31	4/7/2009	10/31/2011	2011
N.T.C.2.19	21227	Longueuil TS M26-ID12550-Tx Malbouef Solar Farm	30	6/10/2011	11/28/2013	2013
N.T.C.1.44	23246	Longueuil TS T3/T4	36	5/1/2014	4/26/2017	2017
N.T.C.2.21	21610	Main TS HV Breakers	31	10/1/2011	4/30/2014	2014
N.T.C.2.19	21503	Malden TS-M8-ID 689-Tx-PV mitigation	29	10/31/2012	4/14/2015	2015
N.T.C.2.19	21530	Martindale TS- M7- ID12840- Tx-SkyPower Val Caron	32	8/26/2011	4/28/2014	2014
N.T.C.1.25	19469	Microwave Replacement - Phase 3 drawings	35	1/1/2010	11/28/2012	2012
N.T.C.1.80	20391	Midhurst Perimeter Security Upgrade	25	6/30/2011	8/2/2013	2013
N.T.C.2.19	21000	Midhurst TS M4 ID12220-Tx RE Midhurst 3	32	2/14/2011	10/23/2013	2013
N.T.C.2.19	21004	Midhurst TS M9 ID12210-Tx RE Midhurst 6	32	3/1/2011	10/29/2013	2013
N.T.C.2.19	21141	Midhurst TS M9 ID12230-Tx RE Midhurst 2	33	2/1/2011	10/30/2013	2013
N.T.C.2.19	21684	Morrisburg TS M25 ID12800 Tx-Southbranch Wind Farm	28	11/3/2011	2/18/2014	2014
N.T.C.2.19	21178	Muskoka TS M10 ID12250-Tx Burks Falls East Solar	28	5/12/2011	8/29/2013	2013
N.T.C.2.19	21582	Napanee TS M3 ID 12390 TX- 2225053 Ontario	31	1/5/2012	7/21/2014	2014
N.T.C.2.03	18623	Nobel SS: Install series capacitor banks	29	7/1/2008	11/30/2010	2010
N.T.C.2.11	18864	North Bay TS: Upgrade to a 115-44 kV TS	25	2/1/2011	2/28/2013	2013
N.T.C.2.03	17260	Northeast Transmission Reinforcement: Install SVC	30	7/1/2008	12/15/2010	2010
N.T.C.2.11	21376	Northgate Minerals- 7km Line Transfer to Hydro One	30	4/8/2011	10/7/2013	2013
N.T.C.2.03	22734	Northwest Special Protection Scheme	24	11/25/2014	12/15/2016	2016
N.T.C.1.42	23244	Orillia TS T1/T2; Component Replacement	25	5/1/2014	5/16/2016	2016
N.T.C.2.19	20871	Otonabee TS M10 ID 12130-Tx Bensfort Road Landfill	29	12/3/2010	4/25/2013	2013
N.T.C.2.11	19948	Ottawa Area- Build Orleans TS	27	4/10/2013	6/28/2015	2015
N.T.C.1.08	22319	OverBrook TS, EOL Transformer Asset Replacement	31	5/12/2015	12/15/2017	2017
N.T.C.1.08	20605	Pickering 'A' SS - Station Re-Investment	36	4/1/2011	3/28/2014	2014
N.T.C.2.19	23302	Picton TS M5 ID24790 Tx-AGRIS Solar Garden 15	27	10/16/2014	1/3/2017	2017
N.T.C.2.19	23334	Picton TS M5 ID25050 Tx-FRITZ solar 34	25	8/12/2014	8/26/2016	2016
N.T.C.2.19	22031	Picton TS M7 ID16620 Tx Sunny Shores Solar Farm	29	1/30/2012	6/30/2014	2014

Driver (Tx)	AR	AR Description	Execution Duration (Months)	Fcst/Actual EMPP	In-Service Date	In-Service Year
N.T.C.2.19	22006	Port Hope TS M17 ID12920-TX Hamilton Port Hope 4	32	12/6/2011	7/25/2014	2014
N.T.C.2.03	21518	Reactors at Marathon TS	31	10/24/2012	5/14/2015	2015
N.T.C.2.19	23110	Recloser Retrofit Project - Tx	27	1/14/2014	3/31/2016	2016
N.T.C.2.19	20700	Red Lake TS-M6-Two Feathers Forest Prdt ID-1777-TX	29	8/4/2010	1/1/2013	2013
N.T.C.2.19	22616	Red Rock HVDS F3 ID20990 Tx-Black Bay Solar	28	1/30/2013	6/15/2015	2015
N.T.C.1.17	18001	Replace Failed Beck R76 400 MVA 230 kV Reg	33	3/19/2010	12/31/2012	2012
N.T.C.1.43	23390	Richview TS T5/T6; Component Replacement	30	12/30/2014	7/13/2017	2017
N.T.C.2.04	20753	Sandusk SS # In-Line Circuit Brks for Pt Dover and	26	9/1/2011	10/28/2013	2013
N.T.C.2.12	20494	Sandusk SS - Port Dover and Nanticoke Wind Project	27	9/1/2011	11/26/2013	2013
N.T.C.1.19	17757	Saunders-St. Lawrence Line Differential Protection	25	9/1/2009	10/15/2011	2011
N.T.C.2.19	22162	Seaforth TS-ID17740-Tx-St Columban 2 Wind Project	34	5/25/2012	3/31/2015	2015
N.T.C.2.19	21074	Smiths Falls TS M21 ID14330-Tx RE Smiths Falls 4	29	6/9/2011	10/23/2013	2013
N.T.C.2.19	21225	Smiths Falls TS M26 ID14320-TX Smiths Falls 3	32	5/20/2011	1/23/2014	2014
N.T.C.2.19	21501	Smiths Falls TS M28 ID14370-Tx Smiths Falls 1	32	6/17/2011	2/6/2014	2014
N.T.C.2.19	21698	St. Lawrence TS M25 ID16470-Tx Glengarry St. Lawre	33	11/28/2011	9/4/2014	2014
N.T.C.1.08	22420	Strathroy TS # EOL Station Refurbishment	36	12/19/2014	12/15/2017	2017
N.T.C.2.19	24005	Striker DS F1 - ID29560 - Tx North Shore Power	26	4/14/2016	6/28/2018	2018
N.T.C.2.19	24007	Striker DS F1 - ID29570 - Tx North Shore Power	26	4/15/2016	6/21/2018	2018
N.T.C.2.19	23320	Sturgeon Falls DS F2 ID24660-TX FRITZ Solar 32	29	7/31/2014	12/16/2016	2016
N.T.C.2.19	23321	Sturgeon Falls DS F2 ID24670-TX FRITZ Solar 31	29	7/31/2014	12/16/2016	2016
N.T.C.2.19	23396	Sturgeon Falls DS - F2 ID24810- Tx AGRIS 14	27	9/24/2014	12/16/2016	2016
N.T.C.2.19	23317	Sturgeon Falls DS - F2 ID24830- Tx AGRIS 13	26	10/8/2014	12/16/2016	2016
N.T.C.2.19	22731	Timmins TS-M11-ID251-Tx PV mitigation	32	5/1/2013	12/16/2015	2015
N.T.C.1.20	22453	To be Closed- CMS Station Service & Yard Supply	26	12/19/2012	2/28/2015	2015
N.T.C.1.40	23453	Walker TS #1 T3/T4; Component Replacement	27	4/22/2015	7/25/2017	2017
N.T.C.2.19	22263	Wallaceburg TS-Feeder M1- ID 17530-SA3	31	5/28/2012	1/7/2015	2015
N.T.C.2.19	20983	Waubaushene TS M1 ID12000-Tx Waubaushene 5	25	1/17/2011	1/31/2013	2013
N.T.C.2.19	21777	Whitby TS M23 ID 15750- Tx Index Energy Mills Road	29	9/13/2012	2/23/2015	2015
N.T.C.2.19	21696	Wilson TS M14 ID16030-Tx Illumination	32	3/22/2013	11/6/2015	2015
N.T.C.1.08	22298	Wiltshire TS - Tx Station Re-investment Project	35	12/18/2013	11/29/2016	2016
N.T.C.2.19	22168	Wingham TS-ID17730-Tx-St Columban Wind Proje	32	8/25/2012	5/6/2015	2015
N.T.C.3.08	22056	WIRELESS SCADA FOR DG Multisite	28	12/31/2008	4/30/2011	2011
N.T.C.1.14	18411	A6P - Line Refurbishment Program (2010-2012)	29	7/15/2010	12/19/2012	2012
N.T.C.2.12	21664	B23D - Connect Grand Bend Wind Farm	25	12/5/2013	12/21/2015	2015
N.T.C.2.12	21762	B563L (Ashfield SS) - Connect K2 Wind Generator	24	3/6/2013	3/10/2015	2015
N.T.C.2.19	19206	Bruce x Milton OPGW	27	2/22/2010	5/16/2012	2012
N.T.C.1.12	23606	C25H # Line Refurbishment	34	6/26/2013	4/14/2016	2016
N.T.C.2.12	20479	Connect the Summerhaven WEC Tx FIT Project	25	7/1/2011	8/8/2013	2013
N.T.C.2.12	21517	Dryden TS - Install Redundant NSD570 for Domtar	25	4/19/2016	5/18/2018	2018
N.T.C.1.15	18371	H2JK & K6J - Replace HV UG Cables	31	5/18/2012	12/14/2014	2014
N.T.C.1.14	20883	Hwy 407 East Ext.-Reloc at Leskard Rd-Recoverable	35	5/24/2013	4/29/2016	2016
N.T.C.2.12	22780	L28C - Connect Green Electron Power Plant	24	2/3/2014	2/11/2016	2016
N.T.C.2.12	22600	Lennox TS 500kV Bus -Connect Napanee GS	32	6/29/2015	3/10/2018	2018
N.T.C.2.03	18839	New 500 kV Bruce to Milton Double Circuit Line	26	3/1/2010	5/14/2012	2012
N.T.C.1.14	18884	P3S/P4S - Line Refurbishment Program (2009-2010)	29	3/2/2009	7/30/2011	2011
N.T.C.2.12	21286	Q6S:Connect the Amherst Island Wind Tx FIT Project	33	7/31/2015	5/2/2018	2018
N.T.C.2.11	23387	"Vaughan MTS#4"- Provide 230 kV Connection	25	6/29/2016	7/30/2018	2018
N.T.C.2.12	20474	White River Tx FIT Projects	29	9/18/2013	2/25/2016	2016
N.T.C.2.12	21787	X3H - Connect Kingston Solar Project	30	3/4/2013	9/3/2015	2015
N.T.C.1.19	20135	2010 Beck #2TS - Q21P Q22P Protection Replacement	18	6/1/2010	12/6/2011	2011
N.T.C.1.19	20170	2010 Newton TS Building Expansion	21	3/31/2010	12/30/2011	2011
N.T.C.2.02	22156	Almonte TS - Install new 230 kV Breaker	17	12/18/2013	5/15/2015	2015
N.T.C.2.19	20981	Almonte TS M28 ID12760 Effisolar Beckwith TX	17	7/3/2012	12/2/2013	2013
N.T.C.1.42	23966	Armitage TS - Paving Upgrade	20	2/2/2015	9/22/2016	2016
N.T.C.1.41	23607	ASW Steel CTS; Hydro One Component Replacement	15	3/2/2015	5/24/2016	2016
N.T.C.1.08	20594	Aylmer TS EOL Asset Replacement	23	6/18/2015	5/15/2017	2017
N.T.C.2.19	23195	Aylmer TS M1 ID21470 TX IGPC Cogeneration Project	16	5/20/2014	9/17/2015	2015
N.T.C.2.21	21471	B5G/B6G - Provide Transfer Trip Protection	18	5/31/2011	12/12/2012	2012

Driver (Tx)	AR	AR Description	Execution Duration (Months)	Fcst/Actual EMPP	In-Service Date	In-Service Year
N.T.C.2.11	19902	Barwick TS: Build a new 115-44 kV TS	13	8/1/2013	9/5/2014	2014
N.T.C.2.19	22977	Barwick TS- M2- ID12030- Tx- Morley Solar Park	12	10/11/2013	10/15/2014	2014
N.T.C.2.19	22989	Barwick TS-M2- ID12040- Tx- Dave Rampel Solar Park	16	10/11/2013	1/30/2015	2015
N.T.C.2.19	23001	Barwick TS-M2- ID12060- Tx- Vanzwolf Solar Park	12	10/11/2013	10/15/2014	2014
N.T.C.2.19	23372	Battersea HVDS - F2 ID25590 - Tx 10 Foster	13	8/26/2014	9/29/2015	2015
N.T.C.2.19	21702	Beaverton TS- M23- ID15880- Tx- GoodLight LP	17	1/15/2013	6/26/2014	2014
N.T.C.2.19	21703	Beaverton TS-M24-ID15900-Tx-Sparkle Light	19	3/22/2013	10/24/2014	2014
N.T.C.2.19	21713	Beaverton TS M24 ID15910 Tx-DiscoveryLight LP	19	3/22/2013	10/24/2014	2014
N.T.C.2.19	23970	Belle River TS M4 ID28210 TX GE004	16	11/3/2015	3/16/2017	2017
N.T.C.2.19	21732	Belleville TS M2 ID16020-Tx - Lunar Light LP	19	6/12/2013	1/15/2015	2015
N.T.C.2.19	21133	Belleville TS M6 ID12360-Tx 2225051 Ontario Inc	23	1/10/2012	12/6/2013	2013
N.T.C.2.11	24363	Bermondsey TS - Support THESL M1 Breaker Upgrade	14	8/26/2016	10/30/2017	2017
N.T.C.2.11	24580	Bermondsey TS - Support THESL M9 and M11 upgrade	16	4/27/2017	8/31/2018	2018
N.T.C.2.19	22451	Brant TS M12 ID20070-TX Ferrero Canada Quattro-Gen	14	9/17/2012	11/10/2013	2013
N.T.C.2.19	21375	Brockville TS M7 ID12140-TX 2176047	18	4/12/2011	9/25/2012	2012
N.T.C.2.19	21674	Brown Hill TS- M12- ID15940- Tx- GoldLight LP	22	3/22/2013	1/20/2015	2015
N.T.C.2.21	20517	Bruce A TS: Address SC Rating of 3 Breakers	20	4/15/2011	12/28/2012	2012
N.T.C.2.21	20575	Bruce A TS: Convert Frame Leakage Prot to B Supp	15	3/28/2011	6/30/2012	2012
N.T.C.2.19	19290	Buchanan TS M22 ID1994 Green Valley Biogas Power P	22	2/22/2010	12/14/2011	2011
N.T.C.2.11	18808	Build New Duart TS	18	6/18/2010	12/13/2011	2011
N.T.C.2.19	23725	Carling TS ID26860 TX Chaudiere Hydro GS2	24	6/30/2015	6/28/2017	2017
N.T.C.1.21	20446	Cherrywood TS Drainage and Roads	23	4/30/2010	3/15/2012	2012
N.T.C.2.19	23319	Chesters Corners DS-F3-ID23540-Tx-AGRIS Solar 1	15	6/26/2014	10/1/2015	2015
N.T.C.2.19	23305	Chesters Corners DS-F3-ID24060-Tx-AGRIS Solar 4	15	6/26/2014	10/1/2015	2015
N.T.C.2.11	19947	Chesterville TS -Add 44kV Feeder	18	6/19/2012	12/18/2013	2013
N.T.C.2.19	21720	Chesterville TS M4 ID16000-TX CityLights LP	14	9/13/2013	11/20/2014	2014
N.T.C.1.21	19274	Claireville TS-Cable Trenches-Repair/Replace	18	1/11/2010	7/24/2011	2011
N.T.C.2.11	18805	Commerce Way TS:Build new TS	23	4/1/2011	2/28/2013	2013
N.T.C.2.19	23354	COUTSVILLE DS-F1-ID25140-TX Gengrowth Garden 06	12	8/31/2014	9/10/2015	2015
N.T.C.2.19	23326	Coutsville DS-F3-ID24,040-Tx-AGRIS Solar 3	16	6/26/2014	10/15/2015	2015
N.T.C.2.19	23380	COUTSVILLE DS-F3-ID25120-TX Gengrowth Garden 05	13	9/29/2014	11/3/2015	2015
N.T.C.2.19	20745	Crysler DS F2 Tx-ID12100 Ferme Geranik Biogas	13	9/1/2010	9/23/2011	2011
N.T.C.2.19	22152	Crystal Falls TS M1 ID18380 Tx-WNPG Turbines Upgrd	17	7/1/2012	12/2/2013	2013
N.T.C.2.19	23366	Crystal Falls TS - M2 ID25360- Tx 07 Rivet	19	8/18/2014	3/23/2016	2016
N.T.C.2.19	23370	Crystal Falls TS - M2 ID25630 - Tx 08 Guenette	18	10/1/2014	3/23/2016	2016
N.T.C.2.02	17061	De Beers Mine in northeast	12	6/16/2010	6/30/2011	2011
N.T.C.1.41	23343	DeCew Falls SS; P&C, Component Replacement	12	5/16/2016	5/19/2017	2017
N.T.C.1.19	21969	Des Joachims W1/HT2 Bus Protection Upgrade	18	5/3/2013	11/7/2014	2014
N.T.C.2.11	20291	Detour Lake - 230kV Mine Connection	16	7/9/2011	10/31/2012	2012
N.T.C.2.19	21645	DG Connection Advancement for $29.76M - TC219	23	7/24/2013	6/30/2015	2015
N.T.C.2.19	22607	Douglas Point TS-M1-ID20930-Tx-Majestic Wind Farm	23	1/16/2013	12/16/2014	2014
N.T.C.2.19	21502	Douglas Point TS-M8-ID11600-Canadian Auto WCW -Tx	21	6/8/2011	3/6/2013	2013
N.T.C.2.11	22918	Dunnville TS: Add 1x27.6kV Feeder Breaker Position	22	9/6/2013	7/12/2015	2015
N.T.C.2.19	23348	Dymond TS - M1 - ID25110-TX Gengrowth Garden 04	17	8/31/2014	1/15/2016	2016
N.T.C.2.19	23375	Dymond TS - M1 - ID25190-TX Gengrowth Garden 01	15	10/1/2014	1/15/2016	2016
N.T.C.2.19	24718	Elgin TS ID31690 TX Alectra Utilities 2MW Cogen	13	6/2/2017	6/30/2018	2018
N.T.C.1.08	20599	Elmira TS, EOL T1, T2 Asset Replacement Project	24	6/29/2012	6/17/2014	2014
N.T.C.2.19	21481	Elmira TS - M1 - ID13310 - Elmira Pet Products	23	4/4/2012	3/6/2014	2014
N.T.C.2.03	18238	Essa TS - Install 245 Mvar Cap Bank	21	2/26/2010	12/1/2011	2011
N.T.C.2.11	24325	Fairchild TS M8 - Support THESL Protection Upgrade	12	6/23/2016	6/23/2017	2017
N.T.C.2.19	23524	Fergus TS - M4 - ID25250- TX Haja	15	11/30/2014	3/8/2016	2016
N.T.C.2.19	23518	Fergus TS - M4 - ID25260-TX Cripton	13	11/30/2014	1/7/2016	2016
N.T.C.2.19	22393	Fergus TS M7 ID19780 TX GSC Muegge	13	10/19/2012	11/26/2013	2013
N.T.C.2.19	24044	Fergus TS M7 ID28770 - Tx Elora GS	14	2/24/2016	4/13/2017	2017
N.T.C.1.25	20730	Fiber Cable Condition Monitoring System	21	11/11/2013	7/31/2015	2015
N.T.C.2.19	20198	Fort William TS ID 767 Skypower Thunde Bay Hy(TX)	13	8/30/2010	10/7/2011	2011
N.T.C.2.19	20184	Fort William TS M5 ID 765 Fort William First (TX)	18	8/30/2010	2/29/2012	2012
N.T.C.3.08	21138	Frame-Relay Replacement Project	14	1/31/2013	3/31/2014	2014

Driver (Tx)	AR	AR Description	Execution Duration (Months)	Fcst/Actual EMPP	In-Service Date	In-Service Year
N.T.C.2.11	22131	Ft. Frances TS: Remove T3 and Reconnect SC1&2	22	12/19/2014	10/20/2016	2016
N.T.C.2.19	21208	Gardiner TS_M14_ID12520_Tx 2225055 ON Hwy2 North	21	10/16/2012	7/3/2014	2014
N.T.C.2.11	21143	Gold Corp # Line Tap from 115 kV line E2R	16	2/1/2012	5/30/2013	2013
N.T.C.2.19	24359	Havelock TS-M1-ID29970-Tx-Antonio West	22	9/30/2016	7/18/2018	2018
N.T.C.2.19	24353	Havelock TS-M1-ID29980-Tx-O'Brien	22	9/30/2016	7/18/2018	2018
N.T.C.2.19	24371	Havelock TS-M1-ID30090-Tx-Card	22	9/30/2016	7/18/2018	2018
N.T.C.2.19	24373	Havelock TS-M1-ID30100-Tx-Conlon	22	9/30/2016	7/18/2018	2018
N.T.C.2.19	24366	Havelock TS-M1-ID30110-Tx-Donovan	22	9/30/2016	7/18/2018	2018
N.T.C.2.19	24362	Havelock TS-M1-ID30130-Tx-Kelly North	22	9/30/2016	7/18/2018	2018
N.T.C.2.19	24375	Havelock TS-M1-ID30140-Tx-Forcier	22	9/30/2016	7/18/2018	2018
N.T.C.2.19	24379	Havelock TS-M1- ID30,170 -Tx- Switzer G	22	9/21/2016	7/18/2018	2018
N.T.C.2.19	24391	Havelock TS-M1-ID30180-Tx-Scheurer	22	9/21/2016	7/18/2018	2018
N.T.C.2.19	24393	Havelock TS-M1-ID30930-Tx-Blakely	22	9/21/2016	7/18/2018	2018
N.T.C.2.19	24395	Havelock TS-M1-ID30940-Tx- Kyte	22	9/21/2016	7/18/2018	2018
N.T.C.2.19	24397	Havelock TS-M1-ID30950-Tx-Cox	22	9/21/2016	7/18/2018	2018
N.T.C.2.19	24381	Havelock TS-M1-ID30960-Tx-McGinn	22	9/21/2016	7/18/2018	2018
N.T.C.2.19	24383	HavelockTS-M1-ID31000-Tx-Lambe	22	9/21/2016	7/18/2018	2018
N.T.C.2.19	24385	HavelockTS-M1-ID31010-Tx-Watson	23	9/21/2016	8/10/2018	2018
N.T.C.2.19	24387	HavelockTS-M1-ID31020-Tx-Kelly South	22	9/21/2016	7/18/2018	2018
N.T.C.2.11	23706	Hawthorne TS T7/T8 DESN: Add 44 kV Breaker for HOL	18	10/24/2016	4/30/2018	2018
N.T.C.2.19	22291	Highbury TS M11 ID19570-TX RE Sunningdale 1	21	7/31/2012	4/17/2014	2014
N.T.C.2.19	24637	Hinchey TS QZ BUS ID32620 Hull2 HOL	16	3/24/2017	7/30/2018	2018
N.T.C.2.11	19210	Horner TS: Install 2 x 27.6 kV Feeder Positions	13	11/1/2010	11/25/2011	2011
N.T.C.2.19	23517	Horner TS - M4 - ID26490-TX Campbell Company of Ca	22	1/15/2014	11/4/2015	2015
N.T.C.2.19	24761	Ingersoll TS M46 ID33650 TX - Greenholm Farms	14	6/30/2017	8/16/2018	2018
N.T.C.2.19	22197	Ingersoll TS M49 ID19610-TX ORSINC 450 Rooftop	20	6/6/2012	2/3/2014	2014
N.T.C.2.04	20307	In-Line Circuit Breakers (Summerhaven)	23	7/1/2011	6/4/2013	2013
N.T.C.2.21	17786	Jarvis TS: Install Current Limiting Reactors & Loa	17	3/1/2010	7/29/2011	2011
N.T.C.2.11	21137	Jungbunzlauer CTS:Provide 115 kV Connection	16	11/25/2011	4/3/2013	2013
N.T.C.2.02	17779	Kapuskasing TS 115KV Breaker Installation	18	1/23/2008	7/30/2009	2009
N.T.C.2.19	20292	Kent TS -M15-Erie Ridge Project - ID 487 - Tx Cost	12	5/7/2010	5/17/2011	2011
N.T.C.2.19	23100	Kent TS M8 ID20260 TX Entegrus Powerlines	15	5/22/2014	8/28/2015	2015
N.T.C.2.19	22283	Kingsville TS M1 ID19900-Tx Oxley Wind Farm	15	11/8/2012	1/23/2014	2014
N.T.C.2.19	22638	Kingsville TS M1 ID21640 Tx - Brian Curtis	14	2/22/2013	5/2/2014	2014
N.T.C.2.19	22550	Kingsville TS M5 ID21110 Tx - Kingvsille Plastic 2	19	3/6/2013	9/30/2014	2014
N.T.C.2.19	22547	Kingsville TS M5 ID21520 - TX - Wigle Ave Solar	15	3/6/2013	6/20/2014	2014
N.T.C.2.19	22545	Kingsville TS-M7-ID20300-200 Clark St -Tx	13	11/26/2012	12/20/2013	2013
N.T.C.2.19	21048	Kirkland Lake TS M62 ID11730-Tx Charlton Dam	13	12/7/2010	12/26/2011	2011
N.T.C.2.19	23898	Kirkland Lake TS - M62 - ID26950 - Tx GT CH4	18	4/26/2016	10/16/2017	2017
N.T.C.2.19	23918	Kirkland Lake TS - M62 - ID26970 - Tx GT CH2	21	4/19/2016	1/10/2018	2018
N.T.C.2.19	23925	Kirkland Lake TS - M62 - ID26980 - Tx GT CH9	17	4/26/2016	9/22/2017	2017
N.T.C.2.19	23927	Kirkland Lake TS - M62 - ID26990 - Tx GT CH13	16	4/26/2016	8/27/2017	2017
N.T.C.2.19	23929	Kirkland Lake TS - M62 - ID27000 - Tx GT CH7	16	4/21/2016	8/23/2017	2017
N.T.C.2.19	23936	Kirkland Lake TS - M62 - ID27010 - Tx GT CH14	16	4/26/2016	8/27/2017	2017
N.T.C.2.19	23940	Kirkland Lake TS - M62 - ID27140 - Tx GT CH3	19	4/26/2016	11/30/2017	2017
N.T.C.2.19	23931	Kirkland Lake TS - M62 - ID27150 - Tx GT CH8	17	4/26/2016	9/22/2017	2017
N.T.C.2.11	18067	Kirkland Lake TS: Reconnect Idle K4 Line	16	6/1/2010	9/22/2011	2011
N.T.C.2.12	21663	L7S - Connect Goshen Wind Energy Centre	18	7/10/2013	1/22/2015	2015
N.T.C.2.03	20518	Lambton to Longwood Transmission Upgrade	22	11/21/2012	9/30/2014	2014
N.T.C.2.19	23286	Lauzon TS DESN2-M26- ID22580- Tx- Manning Pumping	20	7/29/2014	4/11/2016	2016
N.T.C.2.19	24641	Lisgar TS QZ Bus ID32610 Tx 1GS HOL	16	3/24/2017	7/30/2018	2018
N.T.C.2.19	23085	Lorne Park TS M4 ID22470-TX C2-5 Biogas Handling	17	7/24/2014	12/23/2015	2015
N.T.C.2.02	23471	M20/21D Install 230 kV In-Line Switches	20	2/26/2016	10/27/2017	2017
N.T.C.2.19	21203	Manitouwadge TS M2 ID931 Tx-Becker Cogen	23	12/23/2011	12/6/2013	2013
N.T.C.2.19	24010	Manotick DS F5 ID28120 TX 7251572 Canada Ltd.	16	6/9/2016	9/25/2017	2017
N.T.C.2.11	18409	Marchwood MS - 2nd Tap Connection	23	3/30/2012	3/7/2014	2014
N.T.C.2.19	23030	Meadowvale TS M3 ID22460-TX CCS-Mississauga Gen	21	10/13/2015	7/27/2017	2017
N.T.C.2.02	20509	Midhurst TS & Orillia TS: Install 4 LV Cap Banks	17	1/19/2011	6/7/2012	2012

Driver (Tx)	AR	AR Description	Execution Duration (Months)	Fcst/Actual EMPP	In-Service Date	In-Service Year
N.T.C.1.42	23378	Midhurst TS T1/T2; Component Replacement	20	4/13/2015	12/12/2016	2016
N.T.C.1.18	21800	Milton SS Generator Replacement	24	5/28/2013	5/21/2015	2015
N.T.C.2.21	24337	MSO and Jumper Installations	16	6/20/2016	10/8/2017	2017
N.T.C.2.11	21167	Muskoka TS - Add 44kV Fdr Position &Chnge CT Ratio	17	8/27/2012	2/15/2014	2014
N.T.C.2.23	24536	Muskoka TS Cap-Switcher Installation	20	12/9/2016	7/25/2018	2018
N.T.C.1.08	18192	Nanticoke TS-'A' & 'B' Protection Separation	16	8/17/2009	12/31/2010	2010
N.T.C.1.41	23843	Nanticoke TS; CGVB Switch Replacement	18	5/30/2016	11/24/2017	2017
N.T.C.2.23	24213	Napanee TS Cap-Switcher Installation	12	10/25/2016	11/3/2017	2017
N.T.C.2.19	20516	Napanee TS M2 ID1505 Lennox #3 (Tx)	23	6/16/2010	5/12/2012	2012
N.T.C.2.19	24066	Napanee TS - M2 - ID29150 - Tx - SFF 14 Solar PV	20	3/30/2016	12/1/2017	2017
N.T.C.2.19	24068	Napanee TS - M2 - ID29160 - Tx - SFF 09 Solar PV	20	3/30/2016	12/1/2017	2017
N.T.C.2.19	24075	Napanee TS - M2 - ID29190 - Tx - SFF 23 Solar PV	18	3/30/2016	10/1/2017	2017
N.T.C.2.19	24076	Napanee TS - M2 - ID29220 - Tx - SFF 01 Solar PV	18	3/30/2016	10/1/2017	2017
N.T.C.2.11	20968	Nebo TS:Increase Capacity of 230/27.6 kV T1T2 DESN	19	5/3/2012	12/20/2013	2013
N.T.C.2.19	22363	Neustadt DS F2 ID18550-Tx Normanby Solar 3	15	12/14/2012	3/3/2014	2014
N.T.C.1.25	23865	Niagara Area Fiber Infrastructure Development	13	9/3/2015	9/30/2016	2016
N.T.C.1.25	20918	Niagara TS Telecom Relocation	20	5/1/2011	12/19/2012	2012
N.T.C.2.21	20270	Orangeville TS: Motorize B4/5V Ground Switches	18	5/1/2010	10/28/2011	2011
N.T.C.2.19	22091	Orillia TS M1 ID16880-TX H06-3225 Monarch	24	7/30/2012	7/15/2014	2014
N.T.C.2.19	22257	Orillia TS M4 ID17100 625 Harvie Orillia	12	6/4/2012	6/7/2013	2013
N.T.C.1.42	23664	Orillia TS: Spill Cont. & Component Replacements	13	12/20/2016	1/24/2018	2018
N.T.C.2.21	22656	Oshawa Wilson TS: Install Neutral Reactors	12	7/29/2014	7/31/2015	2015
N.T.C.2.19	22269	Otonabee TS M27 ID18480-TX Lakefield College Schoo	15	7/7/2012	10/11/2013	2013
N.T.C.2.19	23933	Parry Sound TS M4 ID 27760-TX-Lakeland Power	19	2/26/2016	10/6/2017	2017
N.T.C.1.29	23268	Physical Security	20	10/7/2014	6/9/2016	2016
N.T.C.1.29	23409	Physical Security Expansion Pilot Project	15	9/29/2016	12/31/2017	2017
N.T.C.2.19	23332	Picton TS M5 ID24800 Tx AGRIS Solar Garden 10	14	9/25/2014	11/26/2015	2015
N.T.C.2.19	21971	Picton TS M6 ID15960 Tx-FotoLight LP	23	11/20/2012	10/28/2014	2014
N.T.C.1.24	18703	PLC Replacement 2007-8 (H22D/L20D/W3C/S1C/P5M)	24	10/31/2006	10/23/2008	2008
N.T.C.2.03	17778	Porcupine TS - Install 2x100 MVAr Shunt Cap Bank	23	2/1/2010	12/31/2011	2011
N.T.C.2.03	21035	Porcupine TS: Modify T7 & T8 Tap Changer Logic	22	2/10/2012	12/18/2013	2013
N.T.C.2.21	22332	Port Arthur TS#1: Install Series Reactors	15	1/23/2013	4/30/2014	2014
N.T.C.3.08	21799	Provincial Mobile Radio System Expansion	18	10/15/2013	3/31/2015	2015
N.T.C.2.21	20573	Put 230kV Inline Switch on X1P at Massanoga Jct	14	11/5/2012	1/15/2014	2014
N.T.C.2.11	23231	Rainy River Gold Project	14	10/30/2015	12/20/2016	2016
N.T.C.1.14	18416	Recoverable - Newmarket - Relocate Twr 809	15	9/1/2010	11/23/2011	2011
N.T.C.1.43	23391	Richview TS T7/T8; Component Replacement	24	12/15/2014	12/15/2016	2016
N.T.C.3.08	22631	Ring 6 Capacity Remediation Project	13	9/24/2013	10/24/2014	2014
N.T.C.2.19	24613	Riverdale TS ID31620 CHP Carleton University	18	3/8/2017	8/31/2018	2018
N.T.C.2.21	24506	S2B - Surge Arrestors on 115kV circuit	17	1/10/2017	6/14/2018	2018
N.T.C.2.19	24059	Schomberg DS F4 ID29370 TX Foothill Greenhouses	14	4/26/2016	6/17/2017	2017
N.T.C.1.80	22121	Scott TS Perimeter Security Upgrade	13	2/17/2012	3/19/2013	2013
N.T.C.2.19	21476	Smiths Falls TS M23 ID14460-Tx Burritts Rapids	23	6/8/2011	4/30/2013	2013
N.T.C.1.25	18188	SONET Sync Clock Replacement	18	6/30/2011	12/31/2012	2012
N.T.C.1.42	23430	Stayner TS T3/T4; Component Replacement	16	6/25/2015	10/24/2016	2016
N.T.C.2.11	19946	St Isidore TS: Add 44 kV Feeder breaker	16	2/21/2014	6/9/2015	2015
N.T.C.2.19	20379	St. Isidore TS- M2- ID 1212- St. Isidore B	19	3/17/2010	10/26/2011	2011
N.T.C.2.19	21076	St Isidore TS_M2_ID12,330_Lafleche Landfill Gas_Tx	21	3/2/2011	12/12/2012	2012
N.T.C.2.19	21811	St. Isidore TS M2 ID14420-Complexe JR Brisson	19	10/18/2011	5/27/2013	2013
N.T.C.2.19	22246	Strathroy TS-M1-ID 17870-Tx-Ruby Farms Solar One	14	5/23/2012	7/15/2013	2013
N.T.C.2.19	22458	Strathroy TS-M3-ID 21170-Tx-RE Adelaide 1 ULC	13	11/6/2012	11/25/2013	2013
N.T.C.2.19	23465	Striker HVDS F2 ID25090 Tx Solvation-VF	14	10/3/2014	12/11/2015	2015
N.T.C.2.19	23350	Striker HVDS F2 ID25150 Tx Solvation-V	14	10/16/2014	12/11/2015	2015
N.T.C.2.19	23486	Striker HVDS F2 ID25180 Tx Solvation-S	16	10/17/2014	2/5/2016	2016
N.T.C.2.19	23329	Striker HVDS F2 ID25200 Tx Solvation-F	17	10/3/2014	3/1/2016	2016
N.T.C.2.19	23584	Tillsonburg TS-M2-Tx work_DG 281 and 282	16	1/29/2015	5/29/2016	2016
N.T.C.2.11	23889	Tomken TS: Revenue Metering Upgrade	20	1/12/2016	9/18/2017	2017
N.T.C.2.11	18671	TREMAINE TS : Build New Transformer Station	19	5/6/2011	12/17/2012	2012

Driver (Tx)	AR	AR Description	Execution Duration (Months)	Fcst/Actual EMPP	In-Service Date	In-Service Year
N.T.C.2.12	21656	W2S - Connect Suncor Adelaide Wind Power Project	18	8/30/2013	2/25/2015	2015
N.T.C.2.19	21691	Waubaushene TS M2 ID15860-Tx Aria LP	24	10/7/2013	9/29/2015	2015
N.T.C.2.19	24036	Wilson TS M1 ID29460-TX Oshawa PUC Microgrid Resea	16	4/5/2016	8/14/2017	2017
N.T.C.2.19	23477	Wilson TS M6 ID22420-TX Oshawa PUC Networks Inc La	15	8/29/2014	11/30/2015	2015
N.T.C.2.12	21830	B22D- Connect Armow Wind Farm	20	3/4/2014	11/12/2015	2015
N.T.C.2.12	21655	B562L (Evergreen SS) - Connect JAB windfarms	19	1/4/2013	8/6/2014	2014
N.T.C.2.12	23904	C23Z :Connect Belle River Wind Project	14	6/22/2016	8/31/2017	2017
N.T.C.2.12	21644	Connect Bluewater Wind Energy Centre	17	4/17/2013	9/8/2014	2014
N.T.C.2.12	20131	Connect the Samsung Chatham Tx Project	20	5/30/2012	2/7/2014	2014
N.T.C.2.12	20132	Connect the Samsung Nanticoke Tx Project	22	11/22/2012	10/2/2014	2014
N.T.C.2.12	20493	Dufferin Wind Farm Project	18	5/9/2013	10/25/2014	2014
N.T.C.2.12	23634	Gemini Power - Smooth Rock Fls Upgrade	18	3/9/2016	9/17/2017	2017
N.T.C.1.14	21032	Guelph-Line Modification of B5G/B6G_Recoverable	15	12/9/2011	2/28/2013	2013
N.T.C.1.12	23505	J5D, Keith TS-Mid R. JCT Waterman, Tx Line Refurb.	18	3/4/2016	8/25/2017	2017
N.T.C.1.15	22931	John TS to Esplanade TS Tunnel Water Mgt Sys Upgrd	19	3/14/2014	10/9/2015	2015
N.T.C.2.12	22351	Mississagi TS - Add Goulais Wind to GR Scheme	23	6/25/2013	5/22/2015	2015
N.T.C.2.12	22496	Mississaugi TS - Add Bow Lake Wind to GR Scheme	22	7/18/2013	5/22/2015	2015
N.T.C.2.12	20486	Namewaminikan Tx FIT Project Connection	22	8/4/2015	6/15/2017	2017
N.T.C.2.12	23462	New Post Creek GS Connection	12	12/14/2015	12/15/2016	2016
N.T.C.2.12	21285	Niagara Region Wind Farm Tx FIT Project	18	3/20/2015	9/29/2016	2016
N.T.C.2.12	21447	Northland Power FIT Connection-Long Lake Solar	21	8/20/2013	5/28/2015	2015
N.T.C.1.14	20864	Oshawa-Hwy 407 E Ext. Thickson Road_Recoverable	13	4/29/2011	5/31/2012	2012
N.T.C.1.12	23790	Q11/12S - Beck GS #1 "Super" Str. Refurb + Conduct	15	2/15/2016	5/25/2017	2017
N.T.C.1.15	22449	Riverdale TS Pumping Plant Replacement	13	11/6/2013	12/15/2014	2014
N.T.C.1.12	20453	S2B Steel Structure Replacement	17	6/5/2012	10/30/2013	2013
N.T.C.1.14	20151	Toronto-TTC Maintenance Facility_Recoverable	18	1/11/2012	7/9/2013	2013
N.T.C.1.14	23960	Two Abandoned Towers near E2R Removal Non-Recovera	22	2/23/2016	12/16/2017	2017
N.T.C.1.12	23682	Tx Lines Insulator Replacement SGB	14	10/21/2016	12/15/2017	2017
N.T.C.1.14	21680	Waterloo - LRT _ Recoverable	14	2/18/2014	4/30/2015	2015
N.T.C.2.12	20495	X22: Connect White Pines Wind Farm Tx FIT Project	21	5/16/2016	2/1/2018	2018
N.T.C.2.12	19534	YEC 393 MW Generation Connections	13	10/12/2010	11/8/2011	2011
N.T.C.2.11	18408	2010 Kitchener MTS#9 Tap Connection	9	3/9/2010	12/21/2010	2010
N.T.C.2.19	24339	Almonte M25 ID 63 # Mississippi River Power SCADA	11	3/6/2017	1/31/2018	2018
N.T.C.2.19	24000	Almonte TS M25 ID26880 TX Enerdu Generation Expans	6	12/18/2015	6/30/2016	2016
N.T.C.2.11	21170	Arlen MTS - Provide Line Connection for New MTS	6	5/31/2011	11/30/2011	2011
N.T.C.1.14	21403	B10/B20H Reconductoring Project	9	8/3/2011	4/30/2012	2012
N.T.C.2.11	20530	Bathurst TS: Provide Additional Breaker Positions	5	7/27/2011	12/21/2011	2011
N.T.C.2.11	24566	BATHURST TS:Support Breaker Installation for THESL	6	6/8/2017	12/6/2017	2017
N.T.C.2.19	22278	Beamsville TS M3 ID17460 Niagara Catholic TX	3	5/25/2012	8/22/2012	2012
N.T.C.2.12	19531	Beck #1 SS - Install Bus Work in G9 Bay	5	4/15/2010	9/1/2010	2010
N.T.C.2.11	25214	Bermondsey -M23 & M26 relay & fibre duct supp work	2	6/26/2018	8/17/2018	2018
N.T.C.2.19	23689	Birch TS M3 ID 27030 TX CMC CHP	11	5/28/2015	4/21/2016	2016
N.T.C.2.19	23683	Birch TS M8 ID 27060 TX Thunder Bay RHSC CHP	8	4/30/2015	12/16/2015	2015
N.T.C.2.11	18455	Bloomsburg MTS Modification	2	10/13/2009	11/30/2009	2009
N.T.C.2.19	22791	Brant TS M14 21700 GEDS - 29: St. George - German	3	6/13/2013	9/12/2013	2013
N.T.C.2.11	23981	Bridgman TS - THESL T12/T13 13.8 kV Cable Upgrades	7	11/30/2015	6/20/2016	2016
N.T.C.2.11	23275	Bridgman TS - Toronto Hydro 13.8kV Cable Upgrades	10	2/5/2015	12/15/2015	2015
N.T.C.2.19	24592	Brocks Beach DS F2 ID 30820 - TX - Storage Zone	3	1/25/2017	5/10/2017	2017
N.T.C.2.19	23531	Brockville TS ID26230 TX 2MW Cogeneration System	11	1/16/2015	12/31/2015	2015
N.T.C.2.21	22681	Brockville TS: Install Neutral Reactor	9	2/21/2013	11/29/2013	2013
N.T.C.2.19	23737	Brockville TS M5 & B1R ID27020 TX Invista Maitland	6	6/25/2015	12/22/2015	2015
N.T.C.2.19	22892	Brockville TS M7 Tx-ID12140 Station Anti-islanding	10	7/10/2013	4/30/2014	2014
N.T.C.2.19	22459	Buchanan TS M25 ID16970 London Health Science Cntr	11	8/31/2012	8/8/2013	2013
N.T.C.2.12	20447	Bus-tie Reactor at Walker #1 TS	7	3/1/2011	9/15/2011	2011
N.T.C.2.19	23747	Caledonia TS M3 ID26810 TX Oneida Business Park	5	5/8/2015	10/9/2015	2015
N.T.C.2.19	23464	Campbell TS M14&24 ID25800-TX-Guelph-Ind EnergyCtr	11	10/28/2014	10/7/2015	2015
N.T.C.2.19	24054	Carling TS KY Bus ID29920 TX The Royal Ottawa Coge	4	5/3/2016	9/9/2016	2016
N.T.C.2.12	19783	Chatham 101.2 MW Wind Farm Connection	3	5/25/2010	9/1/2010	2010

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N.T.C.2.19	21361	Cobalt DS F2 ID12500-Tx Latchford Dam	9	6/14/2011	3/1/2012	2012
N.T.C.2.19	21463	Cobalt DS F2 ID12630-Tx Latchford Dam 2	8	7/13/2011	3/1/2012	2012
N.T.C.2.12	20472	Connect the Pointe Aux Roches Wind Tx FIT Project	7	4/25/2011	11/9/2011	2011
N.T.C.2.19	24338	Cooksville TS-EZ Bus-ID28280-Lakeview Water Treatm	8	10/30/2016	7/1/2017	2017
N.T.C.2.11	22032	Crawford TS -Recoverable Review and Monitoring	1	11/25/2011	12/20/2011	2011
N.T.C.2.19	20877	Crowland TS M13 ID12400-Tx Wainfleet WInd Energy	3	3/10/2014	6/13/2014	2014
N.T.C.2.19	25126	Crowland TS M19 ID35130 TX - GE BTM	6	1/3/2018	7/13/2018	2018
N.T.C.1.14	22947	Cumberland - Tamarack Watermain - Recoverable	4	11/1/2013	3/5/2014	2014
N.T.C.1.14	20899	D1A/D3A - Line Refurbishment Project (2013)	8	4/8/2013	12/15/2013	2013
N.T.C.1.19	21161	Des Joachims A Bus Protection Upgrade	7	2/25/2011	9/11/2011	2011
N.T.C.1.19	21968	Des Joachims H Bus Protection Upgrade	5	5/9/2012	10/11/2012	2012
N.T.C.2.19	21759	Dobbin TS-M7-ID16540-Tx-Trent University Peterbo	8	9/15/2012	5/1/2013	2013
N.T.C.2.19	24073	Dundas TS M8 ID29310 TX Neven Produce CoGen	12	5/18/2016	5/10/2017	2017
N.T.C.2.19	23201	EdgewareTS-M7- ID24300- Tx- Formet 800 kW CHP Sys	3	5/19/2014	8/29/2014	2014
N.T.C.2.19	24861	Elmira TS M1 ID33390 Tx-Elmira Solid Battery SS	7	7/25/2017	2/16/2018	2018
N.T.C.2.19	22106	Elmira TS M2 ID18,280 Tx- 1541 Floradale	4	7/1/2012	10/16/2012	2012
N.T.C.2.19	22107	Elmira TS M2 ID18,290 Tx- 5328 Arthur Street North	9	7/4/2012	3/27/2013	2013
N.T.C.2.19	22741	Elmira TS M2 ID20,550 Tx- 1551 Floradale	5	6/24/2013	11/19/2013	2013
N.T.C.2.19	24082	Erindale TS - M42 - ID29470 - PepsiCo	7	4/19/2016	11/4/2016	2016
N.T.C.2.19	24567	Espanola TS - M2 - ID30900 - Helios Queensway	2	1/9/2017	3/1/2017	2017
N.T.C.2.02	18545	Essa TS x Stayner TS Two Circuit 230 kV Line	1	6/15/2009	7/17/2009	2009
N.T.C.2.11	23698	Essex TS - Connect Enwin Feeder to M10 Breaker	2	9/15/2015	12/4/2015	2015
N.T.C.2.19	22221	Everett TS M6 ID20180-TX Norus Solar 1	2	7/10/2012	9/6/2012	2012
N.T.C.2.11	23015	F2B Protection Changes at Ft. Frances TS	6	4/15/2015	10/26/2015	2015
N.T.C.2.11	22061	Festival Hydro: Provide Line Connection to New MTS	7	11/22/2012	6/26/2013	2013
N.T.C.2.11	23952	Finch/Warden/Runnymede Customer Fiber Support Work	11	1/4/2016	12/7/2016	2016
N.T.C.2.19	24100	Forest Jura HVDS-ID69-SCADA Upgrade	8	9/26/2016	6/1/2017	2017
N.T.C.1.19	20906	Gardiner EOL Invista Protection Replacement	5	1/27/2011	7/8/2011	2011
N.T.C.2.19	24964	Gardiner TS-M24-33250-Tx-Invista Swordfish	6	11/21/2017	6/1/2018	2018
N.T.C.2.19	22927	Gardiner TS M24,M25 ID22320-TX Kingston Cogen	8	10/30/2013	6/16/2014	2014
N.T.C.2.11	22010	Glendale TS: Relocate Feeder Egress	9	2/9/2012	11/7/2012	2012
N.T.C.2.19	24486	Goderich TS - M4 - ID30870 - Compass LDG	6	9/19/2016	4/3/2017	2017
N.T.C.2.11	21964	Goderich TS - New Feeder Position	10	7/19/2012	5/5/2013	2013
N.T.C.2.12	19392	Gosfield 50.6 MW Wind Project	7	1/4/2010	7/23/2010	2010
N.T.C.2.12	19503	Greenwich Lake Wind Farm	9	6/17/2010	3/31/2011	2011
N.T.C.2.19	22277	Hanover TS-M3-ID18710-Price shonstrom Westario Pow	3	8/15/2012	11/2/2012	2012
N.T.C.2.19	22472	Holland TS M4 ID21190-Tx 430 Holland St West	3	3/12/2013	6/11/2013	2013
N.T.C.1.29	22917	Hub Site IPS Replacement Project	4	8/1/2013	12/15/2013	2013
N.T.C.2.19	22196	Ingersoll TS M49 ID19600-TX ORSINC 160 Rooftop	10	6/6/2012	4/9/2013	2013
N.T.C.2.04	20274	In-Line Circuit Breakers (Spence)	6	6/18/2010	12/10/2010	2010
N.T.C.2.20	17992	Install 115kV Switch at L7S Tap to St Marys Cement	11	5/1/2010	3/31/2011	2011
N.T.C.2.11	22076	Iroquois Falls: Conductor Upgrade	3	6/15/2012	9/15/2012	2012
N.T.C.1.14	19223	Iroquois Falls -Hwy 577 Modifications_Recoverable	3	3/8/2010	5/27/2010	2010
N.T.C.1.19	23872	ITC - L4D L51D Line Protection and Telecom Replace	11	2/22/2017	1/10/2018	2018
N.T.C.1.19	20597	Kapuskasing TS-27H9K Cross Trip	6	4/21/2011	10/18/2011	2011
N.T.C.2.19	22460	Keith TS DESN2 M5 ID21160-TX Vollmer Center Solar	4	10/4/2012	2/14/2013	2013
N.T.C.2.19	24675	Keith TS M1 ID31600 TX - K+S Windsor Salt	10	8/1/2017	6/15/2018	2018
N.T.C.2.19	22625	Kent TS M17 ID21490 - TX - Chatham St N	11	3/6/2013	1/27/2014	2014
N.T.C.2.19	20429	Kent TS-M2-ID273-Kent Breeze-Tx	8	8/17/2010	4/19/2011	2011
N.T.C.2.19	20673	Kent TS-M2-ID274-MacLeod Windmill-Tx	8	8/17/2010	4/19/2011	2011
N.T.C.2.04	21311	KENT TS - Station Upgrade	12	4/6/2011	3/23/2012	2012
N.T.C.2.11	17005	Kingston Gardiner TS: Increase 230-44 kV Capactiy	7	10/30/2008	6/9/2009	2009
N.T.C.2.19	24700	Kingsville TS M4 ID31570 TX - SPN030	2	3/30/2017	5/30/2017	2017
N.T.C.2.19	22595	Kingsville TS M6 ID21740 Tx - 201 Talbot	7	2/15/2013	9/12/2013	2013
N.T.C.2.19	25012	Kleinburg TS M25 ID34330 TX - Husky Energy Strg	10	11/6/2017	8/24/2018	2018
N.T.C.2.19	22654	Lauzon TS DESN2 M25 ID21780 Tx - 400 Manning Rd	5	4/20/2013	9/11/2013	2013
N.T.C.2.19	23519	Lauzon TS - M29 - ID25580 - TX Woodslee Solar Gard	3	11/14/2014	2/27/2015	2015
N.T.C.2.19	25010	Lauzon TS M7 - ID33510 TX WFCU Centre CHP Project	7	12/1/2017	6/29/2018	2018

Driver (Tx)	AR	AR Description	Execution Duration (Months)	Fcst/Actual EMPP	In-Service Date	In-Service Year
N.T.C.2.19	21050	Leitrim DS HawthorneTS M2 Tx-ID11130 Green Soldier	10	5/13/2011	3/20/2012	2012
N.T.C.2.11	22661	Limebank MTS: Connect New Transformer	9	1/17/2014	10/24/2014	2014
N.T.C.2.11	20831	Lower Mattagami Construction Power	1	11/1/2010	12/10/2010	2010
N.T.C.2.19	22796	Malden TS-M9-ID21770-Tx - 5890 Malden Rd	4	5/27/2013	9/11/2013	2013
N.T.C.2.11	21391	Malvern TS: Install M23 & M24 Feeder Breakers	8	6/25/2013	2/24/2014	2014
N.T.C.2.02	22111	Manby 230kV Reconfiguration	7	11/1/2013	6/1/2014	2014
N.T.C.2.19	24227	Minden TS - M3 - ID30220 - Tx Minden GS	8	4/8/2016	12/16/2016	2016
N.T.C.2.19	20525	Mitigation Measures for Windsor Malden - Tx	8	4/30/2010	12/31/2010	2010
N.T.C.2.11	22158	Morrisburg TS -Add 44kV Feeder	11	7/10/2012	6/7/2013	2013
N.T.C.2.19	22666	Muskoka TS M7 ID21310 Tx - Muskoka Rd	6	1/17/2013	7/26/2013	2013
N.T.C.2.21	24042	Nanticoke TS - Emergecy Feeder Connection	10	6/23/2016	5/4/2017	2017
N.T.C.2.19	21609	Nebo TS M8 ID14490-Tx Redeemer University College	8	9/9/2011	5/14/2012	2012
N.T.C.2.19	24720	Nepean TS M24 ID31850 TX Algonquin College cogen	10	8/25/2017	6/29/2018	2018
N.T.C.2.19	23763	Nepean TS M26 ID27820 TX Algonquin College - Cogen	10	6/24/2015	4/11/2016	2016
N.T.C.1.44	23249	Nepean TS T3/T4	1	2/28/2017	3/31/2017	2017
N.T.C.1.14	23457	Newmarket-MTO Hwy 404-Install Access Gates-Recover	1	7/28/2014	8/31/2014	2014
N.T.C.2.19	21678	Norfolk TS M1 ID15080-Tx Bright Power	5	11/30/2011	4/29/2012	2012
N.T.C.2.19	21779	Norfolk TS M1 ID15090 - Tx 510 Main St	9	11/29/2011	9/1/2012	2012
N.T.C.2.19	20554	Norfolk TS M5 ID1345-Tx Port Ryerse	6	5/26/2010	12/7/2010	2010
N.T.C.2.19	22475	Norfolk TS-M6-ID20060-068 Villanova- SE -Tx	12	11/1/2012	10/30/2013	2013
N.T.C.1.14	23175	North York - Anti-Climb - Recoverable	11	3/21/2014	2/28/2015	2015
N.T.C.2.11	20165	Oakville MTS#1 - Provide 230 kV Line Connection	10	9/15/2010	7/26/2011	2011
N.T.C.2.19	22535	Orillia TS M1 ID21260-TX Orillia Power Distributio	2	11/23/2012	2/4/2013	2013
N.T.C.2.19	22238	Orillia TS M4 ID18910 TX Orillia Medical Center	5	6/4/2012	10/29/2012	2012
N.T.C.2.19	22092	Orillia TS M5 ID18220 West Street Storage Solar-Tx	9	5/14/2012	1/28/2013	2013
N.T.C.2.19	22470	Orillia TS M5 ID21340-TX Orillia Power Distributio	0	10/15/2012	10/29/2012	2012
N.T.C.2.19	25031	Otonabee TS - M28 - ID31900 - Tx - GGELP_0026	8	9/27/2017	5/14/2018	2018
N.T.C.2.12	24331	Oxy Vinyls Load Displacement Generator Connection	9	3/28/2017	12/15/2017	2017
N.T.C.2.19	23133	Palmerston TS - M4 - ID 23,580 -Tx- Temporal Power	7	1/29/2014	8/20/2014	2014
N.T.C.1.21	21572	Parkway TS Landscaping Project	5	6/27/2011	11/30/2011	2011
N.T.C.2.19	24576	Parry Sound TS M1 ID 32180 -TX- Parry Energy Store	7	1/25/2017	9/1/2017	2017
N.T.C.1.25	23979	Phase 2: Fiber Cable Condition Monitoring System	4	4/20/2016	8/31/2016	2016
N.T.C.1.29	24600	Porcupine TS; Installation of Physical Security Pe	7	1/18/2017	8/16/2017	2017
N.T.C.2.02	19212	Preston TS - Install 230 kV Line Disconnect Switch	12	10/31/2010	10/28/2011	2011
N.T.C.2.19	23510	Preston TS M24-M30 ID25670 TX Toyota Motor Manufac	11	1/15/2015	12/6/2015	2015
N.T.C.3.06	21624	QFW Sag Monitoring EOL Field Equipment Replacement	6	12/15/2011	5/31/2012	2012
N.T.C.2.04	21263	Reactor Replacements	11	6/1/2011	4/27/2012	2012
N.T.C.2.19	21363	Real Canadian Superstore-Project 12,960-TX-Tomken	6	3/17/2011	9/6/2011	2011
N.T.C.1.14	20150	Recoverable- Ottawa - Goulbourn Forced Road	10	8/31/2010	7/6/2011	2011
N.T.C.1.14	19814	Recoverable-Thunder Bay-Hwy 11/17-Birch Beach(Est)	5	4/30/2011	9/20/2011	2011
N.T.C.1.14	19687	Recoverable -Thunder Bay - Hwy 11/17-Hodder Ave	3	11/30/2010	3/11/2011	2011
N.T.C.1.14	19305	Recoverable -Thunder Bay -Hwy 11/17-MacKenzie Stn	8	8/31/2010	4/30/2011	2011
N.T.C.1.14	19414	Recoverable -Toronto -Spadina Subway - Finch West	5	5/15/2010	10/29/2010	2010
N.T.C.1.14	19292	Recoverable - Toronto - West Don Land H6L Tower 11	8	12/31/2009	9/2/2010	2010
N.T.C.1.15	22672	Ring Gap Refurbishment Project - Various Locations	9	3/3/2014	12/10/2014	2014
N.T.C.2.19	24763	Sidney TS-M1-Existing-Tx-Glen Miller CGS	8	9/3/2017	5/17/2018	2018
N.T.C.2.19	22899	Smiths Falls TS M23 Tx-ID14460 Station Anti-island	7	7/10/2013	1/31/2014	2014
N.T.C.2.19	23832	Smiths Falls TS M25 ID27370 TX 3M Perth Cogen	6	10/13/2015	4/8/2016	2016
N.T.C.2.19	21089	SpencervilleDS_F2_ID12,110_Clearydale Farms_Tx	7	12/21/2010	7/15/2011	2011
N.T.C.2.19	21428	Stayner TS M2 ID12280-Tx Skyway Windfarm	7	8/27/2011	4/1/2012	2012
N.T.C.2.19	22373	Stewartville TS M3 ID20960-Tx 1050 O'Brien Road	10	9/26/2012	7/15/2013	2013
N.T.C.2.19	24388	Stewartville TS-M3-ID31060-Tx-Time Fibre Fit	4	7/19/2016	11/16/2016	2016
N.T.C.2.19	21812	St. Isidore TS M2 ID14430-CEPEO-02 Elementary	9	10/18/2011	7/17/2012	2012
N.T.C.2.19	21813	St. Isidore TS M2 ID14440-Casselman Tire 82kW	4	10/18/2011	2/23/2012	2012
N.T.C.2.19	21775	ST Isidore TS M2 ID15620 - 417 Bus Line Ltd	2	12/15/2011	2/2/2012	2012
N.T.C.2.19	23004	Strathroy TS M4 ID22370 TX Entegrus Powerlines	10	1/9/2014	11/24/2014	2014
N.T.C.2.19	24511	Striker HVDS F2 ID30260 Tx NSPG Fixed 200	7	10/17/2016	5/17/2017	2017
N.T.C.2.19	24515	Striker HVDS F2 ID30270 Tx NSPG Fixed 300	11	10/17/2016	9/16/2017	2017

Driver (Tx)	AR	AR Description	Execution Duration (Months)	Fcst/Actual EMPP	In-Service Date	In-Service Year
N.T.C.2.19	24516	Striker HVDS F2 ID30430 Tx NSPG Fixed 400	11	10/25/2016	10/3/2017	2017
N.T.C.2.11	23235	St. Thomas TS: Second Station Service Supply	9	5/16/2014	1/31/2015	2015
N.T.C.1.14	19813	Thunder Bay-Hwy 11/17-East Connection_Recoverable	5	4/30/2011	9/20/2011	2011
N.T.C.1.14	22200	Thunder Bay -Hwy11/17-Eldorado Beach Rd_Recoverabl	10	2/3/2014	12/20/2014	2014
N.T.C.2.19	24020	Tilbury TS-M1-ID 1477-Tilbury Solar 2 Tx work	10	1/18/2010	11/30/2010	2010
N.T.C.2.19	22776	Tillsonburg TS-M2-ID 21130-Tx-Grid Scale Flywheel	8	5/29/2013	2/5/2014	2014
N.T.C.1.14	22262	Toronto Front and York - Path Tunnel-Recoverable	8	2/22/2013	10/20/2013	2013
N.T.C.2.02	23748	Transfer of Ownership of T8M Line to Hydro One	4	5/14/2015	9/25/2015	2015
N.T.C.2.19	21446	Trout Lake TS M5 ID12970-Tx Merrick Landfill Ga	8	6/6/2011	2/1/2012	2012
N.T.C.2.19	23583	Trout Lake TS M5 ID19960-TX-North Bay Hydro	10	2/25/2015	12/16/2015	2015
N.T.C.2.19	20829	TX - GCD 1136 - COnnection of Amherstburg 3 - 10 M	10	9/2/2010	7/7/2011	2011
N.T.C.2.19	20812	TX - GCD 1137 - Connection of Amherstburg 4 10 MW	10	9/2/2010	7/7/2011	2011
N.T.C.2.20	19225	Uprate 115 KV circuit F11C/F12C	6	6/22/2010	12/12/2010	2010
N.T.C.1.14	22440	Vaughan - Stelltac Park Line Raising	3	1/18/2013	4/15/2013	2013
N.T.C.2.11	24518	Walker TS - Connect Enwin Feeder to M3 breaker	5	6/21/2017	11/15/2017	2017
N.T.C.3.08	20305	WAN Project Stop Gap - Network Access Points	10	5/15/2010	3/22/2011	2011
N.T.C.2.19	22286	Wanstead TS M3 ID19880 TX 4480 Progressive Drive	4	7/10/2012	11/9/2012	2012
N.T.C.2.19	23382	Warren HVDS F2 ID25080 Tx Gengrowth Garden 03 Giro	2	9/24/2014	12/1/2014	2014
N.T.C.2.19	21961	Waubaushene TS M2 ID15870 Tx-RayLight	12	10/9/2013	9/25/2014	2014
N.T.C.2.19	21704	Waubaushene TS M4 ID 14400-Tx Midland PUC	4	11/16/2011	3/8/2012	2012
N.T.C.2.19	21280	Whitby TS_ID13530_C17 Real Canadian Superstore	6	3/4/2011	8/31/2011	2011
N.T.C.2.19	22320	Wilson TS M11 ID19990 Tx 405 Lake Road	12	8/1/2012	7/17/2013	2013
N.T.C.2.19	25307	Woodstock TS M6 ID35770 TX-Woodstock Hospital CHP	1	4/30/2018	5/31/2018	2018
N.T.C.2.12	21665	B4V - Connect Grand Valley Wind Farms (Phase 3)	12	12/16/2014	12/1/2015	2015
N.T.C.2.12	23631	B4V - Connect Southgate Solar Project	10	2/10/2016	12/2/2016	2016
N.T.C.2.11	21465	Bell Creek Complex - 115kV P7G Mine Connection	4	3/15/2012	7/17/2012	2012
N.T.C.1.14	22738	Bell TCA Equipment Change Out - Recoverable	0	12/15/2016	12/20/2016	2016
N.T.C.1.14	23735	BL104 & BSH106 Idle Lines Removal Non-Recoverable	10	7/17/2015	5/30/2016	2016
N.T.C.1.14	22670	Cambridge-MTO-3 Improved Hwy 401 Crossings-Recover	9	11/29/2013	8/24/2014	2014
N.T.C.2.12	20470	Connect the Comber East & West Wind FIT Projects	4	4/25/2011	8/25/2011	2011
N.T.C.2.12	20499	Connect the Liskeard 1,3,4 Tx FIT Project	10	6/3/2013	3/21/2014	2014
N.T.C.2.11	18450	Ellwood MTS 230 kV Connection	8	4/16/2010	11/30/2010	2010
N.T.C.2.12	21661	L29C - Connect East Lake St. Clair Wind	8	10/4/2012	5/30/2013	2013
N.T.C.2.12	24058	L29C - Connect North Kent Wind I Project	10	1/30/2017	11/30/2017	2017
N.T.C.1.14	22154	L5H Idle Line Removal Non-Recoverable	4	8/29/2012	12/31/2012	2012
N.T.C.2.12	20935	Maclean's Mountain Wind Farm	12	2/7/2013	1/23/2014	2014
N.T.C.1.14	23999	Markham-Enbridge-IBM CTS Grounding Mods	2	1/13/2016	2/28/2016	2016
N.T.C.1.14	23468	Metrolinx-Eglinton LRT at Jonesville Cres-Recovera	6	1/18/2017	7/28/2017	2017
N.T.C.2.12	24719	Niagara Region Wind Farm SPS Implementation	8	7/14/2017	3/15/2018	2018
N.T.C.1.14	20881	Oshawa-Highway 407 Extension-Harmony Rd_Recoverabl	9	5/18/2012	2/3/2013	2013
N.T.C.1.14	18173	Oshawa-Hwy 407 Ext.-Halls Road_Recoverable	9	4/18/2011	1/22/2012	2012
N.T.C.1.14	19763	Oshawa-Hwy 407 Ext.-Sideline 4_Recoverable	8	4/18/2011	12/14/2011	2011
N.T.C.1.14	22422	Ottawa - 800 Hunt Club Road_Recoverable	6	9/27/2013	3/21/2014	2014
N.T.C.1.14	17752	Ottawa - Alta Vista Hospital Link - Recoverable	10	7/5/2013	5/15/2014	2014
N.T.C.1.14	19384	Ottawa - Hwy 417 Interchange_Recoverable	9	2/2/2012	11/2/2012	2012
N.T.C.1.14	22518	Ottawa - McRae Structure Replacement - Recoverable	11	11/19/2015	10/14/2016	2016
N.T.C.1.14	20732	Ottawa-Relocation & Raising of H9A_Recoverable	5	1/1/2011	6/5/2011	2011
N.T.C.1.25	22285	Ottawa Telecom Cable Removals	11	8/11/2016	6/30/2017	2017
N.T.C.1.14	22421	P1P Superior Fine Papers Removals-Non-Recoverable	4	11/19/2012	3/31/2013	2013
N.T.C.1.12	22869	Q11S/Q12S - Tx Lines Refurbishment Program	9	8/27/2015	5/30/2016	2016
N.T.C.1.14	20813	Recoverable - Toronto - 570 Bay St.	6	11/1/2010	5/1/2011	2011
N.T.C.1.14	23141	South Huron-Raise L7S for Goshen Wind-Recoverable	11	3/27/2014	2/15/2015	2015
N.T.C.1.14	21460	Thunder Bay - Hwy 11/17-Red Rock-Nipigon_Recovrabl	2	9/30/2013	12/20/2013	2013
N.T.C.1.14	23254	Timminco Idle Line Removal - Recoverable	2	5/21/2014	7/15/2014	2014
N.T.C.1.14	22077	Toronto-GTS Expansion Project-Recoverable	9	12/13/2012	8/31/2013	2013
N.T.C.1.12	25217	Tx Lines Idle Line Removal # Lakeview GS	4	2/27/2018	7/4/2018	2018
N.T.C.2.12	21662	W45LC - Connect Erieau Wind	8	10/4/2012	5/30/2013	2013
N.T.C.1.14	23720	Waterloo-Columbia St Pole Relocation-Recoverable	4	10/27/2015	2/17/2016	2016

Driver (Tx)	AR	AR Description	Execution Duration (Months)	Fcst/Actual EMPP	In-Service Date	In-Service Year
N.T.C.2.12	21667	WT1A - Connect Silvercreek Solar Park	10	9/9/2013	7/3/2014	2014
N.T.C.2.12	23610	Yellow Falls Hydroelectric	11	7/31/2017	6/29/2018	2018
N.T.C.2.12	23561	Z1E: Connect Windsor Solar Project	11	11/27/2015	10/24/2016	2016
N.T.C.1.18	20082	Abandoned Equipment Removal	12	1/14/2010	12/31/2010	2010
N.T.C.2.19	22663	Barrie TS M1, M6 ID 16490 - TX -IBM Data Center	5	3/13/2013	8/7/2013	2013
N.T.C.2.02	18398	Beamsville TS - Cap Bank Removal	1	1/18/2010	2/26/2010	2010
N.T.C.2.19	21682	Beaverton TS M27 ID12270-TX Pukwis Community Wind	23	11/21/2011	10/21/2013	2013
N.T.C.1.14	21474	Bruce B20P/B24P Line Removal Non-Recoverable	3	10/28/2011	1/19/2012	2012
N.T.C.1.25	23292	Clarkson Tower Removal	16	8/1/2014	12/15/2015	2015
N.T.C.2.19	20749	Cobden TS M2 ID1237-Tx SQPV01	6	7/9/2013	12/31/2013	2013
N.T.C.1.14	20949	Copper Cliff Idle Line Removal Non-Recoverable	10	1/30/2014	12/1/2014	2014
N.T.C.2.19	20460	Crystal Falls TS-M1 WNPG-#3 and #7 Turbine Upgrade	16	9/15/2010	12/31/2011	2011
N.T.C.1.29	22633	Cyber Lab	5	9/4/2013	2/1/2014	2014
N.T.C.2.11	20149	Detweiler DESN (T5 & T6):Decommissioning Cost	14	7/31/2013	9/30/2014	2014
N.T.C.1.08	20661	Dundas TS, EOL Asset Replacement Project	33	3/13/2013	12/21/2015	2015
N.T.C.2.19	24334	Dundas TS M1 ID29320 TX eNature Greenhouses Inc	12	5/18/2016	5/3/2017	2017
N.T.C.2.19	21268	Dunnville TS M1 ID11660-Tx Rosa Flora Cogen	1	4/3/2012	5/1/2012	2012
N.T.C.2.19	21486	Elliot Lake TS- M3- ID12690- Tx- Four Slide Falls	38	8/5/2011	10/12/2014	2014
N.T.C.2.19	21508	Elliot Lake TS- M3- ID12740- Tx- McCarthy Chute GS	37	8/5/2011	9/11/2014	2014
N.T.C.2.19	21511	Espanola TS- M2- ID12700- Tx- Wabageshik Ra	40	8/2/2011	11/30/2014	2014
N.T.C.2.19	20734	GCD11bi-Spring Bay Wind Farm-ManitoulinTS-Tx	11	8/5/2010	6/30/2011	2011
N.T.C.2.21	21461	Greenfield South CGS R24C Trans Line Access	13	5/16/2011	6/4/2012	2012
N.T.C.2.19	21450	Hoyle DS F2 ID12680-Tx Wanatango Falls GS	43	8/31/2011	3/31/2015	2015
N.T.C.2.12	22756	Install a MSO on 115 kV line C1A	0	4/12/2013	4/27/2013	2013
N.T.C.2.19	22135	Kapuskasing TS M4 ID17860-TX Hydro Kapuskasing Hyd	35	3/16/2012	2/1/2015	2015
N.T.C.2.19	23190	Kerwood DS F1 ID23700 TX 28453 Kerwood Road	2	8/21/2014	10/17/2014	2014
N.T.C.2.11	20357	Kingston Gardiner #2 TS - Invista Protections	10	1/31/2016	12/15/2016	2016
N.T.C.2.19	21224	Kirkland Lake TS ID 12730- Tx Marter Twp GS	77	2/10/2011	6/30/2017	2017
N.T.C.2.19	21430	Kirkland Lake TS M62 ID12790-Tx Larder and Rave	43	6/17/2011	12/31/2014	2014
N.T.C.2.19	21246	Larchwood TS M4 ID12650-Tx At Soo Crossing GS	68	5/12/2011	1/16/2017	2017
N.T.C.2.19	21251	Larchwood TS M4 ID 12660 - Tx Cascada Falls GS	70	3/15/2011	1/16/2017	2017
N.T.C.2.19	21248	Larchwood TS M4 ID12670-Tx McPherson Fall GS	70	3/15/2011	1/16/2017	2017
N.T.C.1.14	23574	M1T Idle Line Removal Non-Recoverable	9	3/30/2015	12/15/2015	2015
N.T.C.2.19	22260	Malden TS M12 ID18790-Tx River Canard Energy Wind	9	6/15/2012	3/24/2013	2013
N.T.C.2.19	22243	Malden TS M12 ID19180-Tx River Canard Energy N	16	8/5/2012	12/15/2013	2013
N.T.C.2.19	22085	Manotick DS F5 ID 19080 Schouten Farms TX	3	9/30/2012	1/1/2013	2013
N.T.C.2.19	21488	Martindale TS- M5- ID12710- Tx- Allen & Struthers	37	8/9/2011	9/21/2014	2014
N.T.C.2.19	21616	McCrimmon DS F3 ID15050-Tx 1024248 Ontario Inc	7	9/2/2011	4/1/2012	2012
N.T.C.2.19	22375	Neustadt DS F2 ID18540-Tx Normanby Solar 2	4	8/31/2012	1/14/2013	2013
N.T.C.3.08	17666	Non-PSTS Wide Area Network	61	6/1/2011	6/15/2016	2016
N.T.C.2.11	22980	NOTL MTS 1and2 Modifications-Connect to 115 kV	11	7/8/2014	5/31/2015	2015
N.T.C.2.19	22642	Oakville TS#2 M45 ID21100-TX Holcim Waste Heat Rec	8	2/21/2014	10/31/2014	2014
N.T.C.2.11	22394	Pleasant TS - Connect M62 and M69 Feeders	3	11/29/2012	3/1/2013	2013
N.T.C.2.19	21260	Port Hope TS M16 ID12750-TX Clean Breeze Wind Park	32	11/3/2011	6/30/2014	2014
N.T.C.1.14	20284	Recoverable -Aircraft Warning Markers Installation	0	3/20/2010	3/31/2010	2010
N.T.C.1.12	17764	Recoverable - Gloucester - Relocation of Tower 258	11	5/1/2010	3/31/2011	2011
N.T.C.1.14	20580	Recoverable -Toronto - 300 Front St.	30	7/8/2010	12/31/2012	2012
N.T.C.2.19	21043	ReddendaleDS_F2_ID12,260_DeBruin Farm Biogas_Tx	4	3/2/2011	7/15/2011	2011
N.T.C.2.19	21396	Shabaqua DS F2 ID 12150 - Tx McGraw Falls GS	26	5/17/2011	7/24/2013	2013
N.T.C.2.19	21643	St Isidore TS M1 ID14620-TX Kirchmeier Farms PV	4	8/18/2011	12/31/2011	2011
N.T.C.2.11	22331	St. Thomas 115/27.6 (T3 & T4):Decommissioning Cost	24	11/25/2013	11/30/2015	2015
N.T.C.2.19	23315	Sturgeon Falls DS - F2 ID24720- Tx AGRIS 12	15	10/8/2014	1/15/2016	2016
N.T.C.2.19	20457	TC219 Dual Secondary Winding Transformers Limit	9	12/31/2012	9/30/2013	2013
N.T.C.2.19	21418	Tomken TS B Bus ID13470-Tx Enersource Hydro Miss.	4	4/28/2011	8/31/2011	2011
N.T.C.1.14	20283	Tower Removal - S1K	10	3/5/2013	12/31/2013	2013
N.T.C.2.20	21729	Tx Performance Enhancements	0	12/31/2015	12/31/2015	2015
N.T.C.2.20	23560	Tx Performance Enhancement - Thunder Bay PQ (RFP)	9	12/1/2014	8/31/2015	2015
N.T.C.2.19	20787	WalkerTS_M1 & EssexTS_M6 - ID940-TX -Windsor Clean	20	10/6/2010	6/1/2012	2012

Driver (Tx)	AR	AR Description	Execution Duration (Months)	Fcst/Actual EMPP	In-Service Date	In-Service Year
N.T.C.2.03	20400	Wawa TS - Reactor Cap Interlock	4	9/13/2010	12/31/2010	2010
N.T.C.2.19	21467	Weston Lake DS F1 ID12720-Tx Ivanhoe Chute GS	38	8/10/2011	10/12/2014	2014
N.T.C.2.19	21441	Whitby TS M7 ID-14100- TX H06 4200 Garden	4	6/21/2011	10/15/2011	2011
N.T.C.2.11	22635	E4D # Upgrade to operate at Higher Temperature	4	12/12/2017	3/31/2018	2018
N.T.C.1.14	22261	Hwy 401 Holt Road Interchange - Recoverable	11	5/10/2012	4/18/2013	2013
N.T.C.1.14	20641	Toronto -Spadina Subway Tunneling_Recoverable	10	12/31/2011	11/1/2012	2012
N.T.C.1.14	22517	Whitby - O1S - Idle Line Removal - Recoverable	8	4/22/2013	12/15/2013	2013

OEB Staff Interrogatory # 7

Reference:

EB-2017-0364 Evidence, Addendum to the 2017 Updated Assessment for the Need for the East-West Tie Expansion, Reliability Impacts and the Projected System Costs of a Delay to the Project In-Service Date, June 29, 2018 (prepared by the IESO)

In the Conclusion section, the IESO continues to recommend an in-service date of 2020 for the East-West Tie Expansion. The IESO provides that its recommended in-service date is based on applicable planning and reliability criteria to ensure the reliability needs in the Northwest are met and to avoid the additional risks and associated costs of not having expanded transmission capability between the Northwest and Southern Ontario.

Interrogatory:

a) Has the IESO's update in any way impacted Hydro One's proposed project or ability to construct in the timeline that it is proposing? If so, please explain how and provide details.

b) What potential issues in Hydro One's proposal could potentially result in Hydro One's in-service date being delayed past the end of 2022?

Response:

a) No, it has not.

b) Hydro One fully intends to deliver the LSL Project by December 2021. However, Hydro One is cognizant of the fact that there could potentially be delays outside of Hydro One's control. For instance, a delay in obtaining EA Approval after August 2020 could result in the in-service date being delayed past the end of 2022. Hydro One has completed a sensitivity analysis to illustrate the impact of a one, three, five, or twelve-month delays that an EA approval would have on the in-service date and costs of the Project. This is provided in Table 1 below. Hydro One believes the likelihood of the EA being approved after August 2020 to be very low; therefore, an in-service date beyond December 2022 is also unlikely.

Table 1 – EA Approval Date Scenario Analysis					
		EA Delay			
Schedule - Preferred Route	**Baseline**	**1 Month**	**3 Month**	**5 Month**	**12 Month**
Submit Section 92 Application to OEB	Feb-2018	Feb-2018	Feb-2018	Feb-2018	Feb-2018
Projected Section 92 Approval	Jan-2019	Jan-2019	Jan-2019	Jan-2019	Jan-2019
Finalize EPC Contract with SNCL	Feb-2019	Feb-2019	Feb-2019	Feb-2019	Feb-2019
Environment Assessment and Consultation					
Obtain EA Approval from MOECC	**Aug-2019**	**Sep-2019**	**Nov-2019**	**Jan-2020**	**Aug-2020**
Ongoing Stakeholder Consultations	Dec-2021	Dec-2021	Dec-2021	Dec-2022	Dec-2022
Lines Construction Work					
Real Estate Land Acquisition	Mar-2020	Mar-2020	Mar-2020	Mar-2020	Mar-2020
Detailed Engineering	Feb-2019	Feb-2019	Feb-2019	Feb-2019	Feb-2019
Material Deliveries	Jul-2020	Jul-2020	Oct-2020	Dec-2020	Jul-2021
Construction Completion	Sep-2021	Oct-2021	Dec-2021	Nov-2021	Sep-2022
Commissioning Completion	Dec-2021	Dec-2021	Dec-2021	Dec-2021	Dec-2022
In Service Date	**Dec-2021**	**Dec-2021**	**Dec-2021**	**Dec-2021**	**Dec-2022**
Cost Impact ($000s)	**$0**	**$0**	**+$1,359**	**+$4,472**	**+$14,761**

OEB Staff Interrogatory # 8

Reference:

EB-2017-0364 Evidence, Hydro One's Application filed on February 15, 2018, Exhibit B, Tab 7, Schedule 2, Page 2
Incremental Maintenance Costs

Hydro One provides that its existing maintenance programs will be leveraged to perform maintenance on the Lake Superior Link line. The expected maintenance costs of both Hydro One's existing corridor widened to accommodate the Lake Superior Link and new Dorion corridor have been compared and are provided below for reference purposes.

Table 1

Right-of-Way (ROW) Type	Maintenance Program	Average Annual Cost ($000s)
Hydro One's Existing EWT	Vegetation Maintenance	$442
	Overhead Lines Maintenance	$285
	Average Annual Cost	$727
Widened EWT and Dorion ROW – Inclusive of LSL	Vegetation Maintenance	$782
	Overhead Lines Maintenance	$562
	Average Annual Cost	$1,344
Incremental Annual Maintenance Cost-Widened Corridor for Lake Superior Link		**$617**

Maintenance activities, such as patrols on the existing East-West Tie line and the new Lake Superior Link line, will be bundled to improve productivity and reduce mobilization costs. Additionally, the new line will be designed and constructed to meet Hydro One's standards, which will minimize total life cycle cost. All components of the Lake Superior Link project are expected to last more than 50 years. As such, this line does not require component condition assessments for the first 50 years.

Interrogatory:

a) How does Hydro One's forecasted operation and maintenance costs for the Lake Superior Link line compare to that of other Hydro One lines in
   i. Northern and Northwestern Ontario,
   ii. other parts of the province.

b) What have been the annual (i) operations costs; (ii) maintenance costs (broken down into vegetation and overhead line categories); and (iii) administration costs for the existing East-West Tie line for each of the last five years.

c) Please provide a table that compares these circuit costs to the estimated incremental costs for the proposed new Lake Superior Link line on a per km basis.

d) Please show how the estimated vegetation maintenance and overhead lines maintenance costs for the "Widened EWT and Dorion ROW" in Table 1 were calculated and any assumptions on which those numbers are based.

e) Can Hydro One confirm whether its current operation and maintenance practices will be utilized for the purpose of maintaining the Lake Superior Link line?

Response:

a) Hydro One's forecast operation costs are normalized with respect to the total equipment controlled and monitored by System Control. Hence, the forecast cost of operating a similar transmission line will be the same regardless of the location.

   Similarly, Hydro One's forecast maintenance costs for the Lake Superior Link line were developed by averaging actual historic costs incurred across the province and are used to estimate maintenance costs for all Hydro One assets across Ontario. Though the average unit cost is equal for each asset type, select maintenance activities occur on a more frequent cycle in Southern Ontario as compared to Northern Ontario. As a result, overall maintenance costs in Northern Ontario tend to be less than those in Southern Ontario.

b) The approximate annual operating and maintenance costs for the existing East-West Tie line are provided in Table 1 below. Hydro One does not track administration costs by facility.

Table 1 – Operating & Maintenance Costs			
Year	**Operating Cost ($)**	**Maintenance Costs**	
		Vegetation Management -	**Overhead Lines**
2014	$629,000	$9,593	$74,004
2015	$631,000	$107,891	$171,101
2016	$638,000	$3,340,419	$36,549
2017	$660,000	$1,928,918	$123,318
2018[1]	$644,000	$15,776	$109,581

Hydro One would like to note the following annual Vegetation Management costs for the past 5 years are higher than the estimated annual cost for the existing East-West Tie line for the following reasons:

- Hydro One's vegetation maintenance is performed on an 8 year cycle in Northern Ontario and costs are typically averaged over 8 years at a minimum
- Estimated annual costs have been averaged over 30 years. The vegetation management maintenance costs recently incurred by Hydro One on the EWT were higher than estimated in order to remove all non-compatible vegetation and reduce future costs required to maintain the ROW

Annual overhead maintenance costs are lower than the 30 year average annual cost for the existing East-West Tie line ($285k) due to significantly less demand and corrective work required for the EWT in the past 5 years.

c) Table 2 below compares the average per km cost of the existing EWT line to the proposed new LSL line.

	Average 2014-2018 Per Km Spend	**LSL**
Operations	$1,600	$1,531
Maintenance	$1,479	$1,605
Administration	N/A	$583

[1] 2018 maintenance costs are a year-end projection based as of September 2018.

d) Estimated maintenance costs for the new Lake Superior Link were calculated as follows:

- Unit pricing was used to calculate the costs to perform maintenance on the LSL for 30 years. These costs were then averaged to determine an annual cost.
- Vegetation maintenance is performed on an eight year cycle and overhead lines maintenance is performed on a five year cycle in Northern Ontario.
- The cost of all overhead maintenance activities will double to maintain both the EWT and LSL transmission lines.
- Specific to vegetation maintenance cost, the ROW within Pukaskwa National Park will not be widened, hence, maintenance costs will remain equal to the costs incurred to maintain the existing East-West Tie through the park. Outside of Pukaskwa National Park, the remainder of the EWT corridor will double in width to accommodate the Lake Superior Link, hence, the expected maintenance costs will double.
- Line clearing is one of the major vegetation maintenance activities performed by Hydro One and entails removal of danger trees along the edge of Hydro One's ROWs. By widening the EWT and adding the Lake Superior Link to this existing corridor, additional line clearing costs will only be incurred along the Dorion ROW.

e) Yes, Hydro One's current operation and maintenance practices will be utilized for the purpose of maintaining the Lake Superior Link line.

OEB Staff Interrogatory # 9

Reference:

EB-2017-0364 Evidence, Hydro One's Application filed on February 15, 2018, Exhibit B, Tab 7, Schedule 2, Pages 1-4
Incremental Operating and Administrative Costs

Hydro One states that incremental operating costs for the Lake Superior Link project are estimated to be $647,000 annually by Hydro One. These are the costs of controlling and monitoring the equipment directly associated with these four new 230 kV transmission lines that are located within the three Hydro One-owned transformer stations. The assets defined for the purposes of this proposal are the four new 230 kV transmission lines (W35M, W36M, M37L, and M38L) from the first structure just outside of the three Hydro One-owned transformer stations (Wawa, Marathon and Lakehead TS).

Hydro One's forecast of the Operational, Maintenance and Administrative (OM&A) costs related to the Lake Superior Link project is $1.5 million per year. Hydro One explained the incremental costs for their maintenance program in the widened corridor and in the Dorion right-of-way and estimated that these incremental costs are $617,000 on average per year. In addition to incremental maintenance costs, Hydro one allocated approximately $235,000 for administrative costs and other unforeseen expenditures related to the Lake Superior Link project.

Interrogatory:

a) What is the project's estimated average total operating costs per year? Please explain how Hydro One calculated the estimated incremental operating cost of $647,000.

b) Please provide the annual operating cost for the three Hydro One-owned stations for each of the last five years and comment on the estimated increase allocated for each station.

c) Please provide the annual operating costs for other comparable 230 kV lines and stations in Northern Ontario.

d) What would be the impact, if any, on the estimated operating cost of the three stations, if NextBridge's application is approved instead of Hydro One's Lake Superior Link project?

e) Please explain how Hydro One calculated the estimated incremental administrative cost of $235,000. How did Hydro One assure itself that this allocation is reasonable?

f) Please provide a breakdown of the operational costs itemized per services listed in the evidence on Exhibit B, Tab 7, Schedule 2, page 3, lines 18-27.

g) Please describe the measures, in addition to those discussed in the evidence, to manage the risk associated with:
   i. Maintenance costs
   ii. Operational costs
   iii. Administrative costs

Response:

a) Hydro One uses a proportional asset model to determine the operating cost with respect to the total number of assets and SCADA points serviced by System Control.

This model uses the overall transmission operating cost, the total number of SCADA points serviced by Hydro One, total number of circuit kilometers operated, and total number of load-serving transformers operated to determine the unit cost of each SCADA point, the per kilometer unit cost of operating a transmission line, and the unit cost of each step-down transformer. These values can then be adjusted to determine the operating cost of any portion of the transmission system. The operating cost will vary depending on the type of service requested (only real-time operation, real-time operation plus outage planning and/or work protection). Based on historical average of operating similar lines, it is estimated that this will cost $647,000 annually, as provided in Exhibit B, Tab 7, Schedule 2.

b) Determining the operating cost of these Hydro One owned stations is difficult as the model is ideally used for transmission lines and load-serving stations. However, any increase in operational costs at these stations (Wawa, Marathon, Lakehead) will be limited to the increase in SCADA points. Since the unit cost for each SCADA point ranges from $200-$300/point, the increase in cost will be minimal. Also, some of these additional SCADA points have already been accounted for in the estimated incremental operating cost of $647,000.

c) As stated in Exhibit I, Tab 1, Schedule 8, the annual operating costs for other comparable 230 kV lines and stations will be identical due to the proportional costing methodology that is used by Hydro One.

d) There is no expected material increase in operating cost at the three Hydro One stations if NextBridge's application is approved, the exception being the SCADA point costs aforementioned.

e) The administration costs are a placeholder for any incremental cost associated with the new facilities that Hydro One may incur. Incremental foreseen costs may include costs to complete permitting associated with real estate, ongoing Indigenous community consultation, environmental conditions of approval as well as any conditions required by the OEB to report on the LSL.

f) Hydro One's operational costing methodology does not split the operational cost based on each itemized service. Most of these services are understood to be real-time operational services and are already accounted for under the internal operating cost (overall transmission operating cost). However, the cost associated with outage planning and Issuing Authority under the Utility Work Protection Code can be determined. As part of the $647,000 operational cost for 2017, approximately $120,000 is estimated to be for outage planning services and $30,000 for work protection services.

g) Hydro One has a storied history of operating and maintaining transmission lines throughout the Province of Ontario. Hydro One is confident that the incremental estimate provided is reasonable to operate and maintain the LSL facilities that are subject to leave to construct approval in this application.

OEB Staff Interrogatory # 10

Reference:

EB-2017-0364 Evidence, Hydro One Undertaking Response JT2.21
Hydro One's Construction Cost Estimates

In response to undertaking JT2.21 filed on May 25, 2018, Hydro One provided construction cost estimates for the route using the same cost categories as in Table 2 of NextBridge's response to CCC #8. In its undertaking response, Hydro One provided explanations for cost variances where in Hydro One's view the variances were substantial.

Interrogatory:

a) With respect to costs of materials and equipment, Hydro One's estimate is approximately 34% lower than NextBridge's. Please specify and explain the cost reduction driven by each of the following factors:
   i. Optimized tower design
   ii. Shorter length of the line
   iii. Global purchasing power
   iv. Any other factors

b) Please advise as to how Hydro One calculated the materials and equipment cost of approximately $58 million and any assumptions on which that calculation was based?
   i. Is any portion of the $58 million amount part of the proposed fixed price EPC contract with SNC-Lavalin? If so, how much?

c) With respect to the "Land Rights" cost category, Hydro One's estimate is significantly lower than that of NextBridge. Please explain:
   i. In detail how Hydro One calculated a land rights cost that is only 41% of the estimate provided by NextBridge?
   ii. Why the estimated costs of the Land Rights do not vary whether Hydro One goes through or around Puskaskwa National Park? Are there not additional land rights costs that would be incurred if Hydro One has to go around the Park?
   iii. What are the "instruments" that Hydro One is considering in acquiring land rights? What are the cost associated with each of these instruments?
   iv. What is the basis for Hydro One's belief that it will reach "voluntary settlements" with the vast majority of property owners?
   v. What are the total estimated costs associated with voluntary settlements?

vi. What are the total estimated land rights acquisition costs for the properties where voluntary agreements could not be reached?
vii. What is Hydro One's timing in acquiring land rights?

d) Hydro One allocated over $18 million to the First Nation and Métis Participation cost category. Hydro One noted that this funding was accounted for in the Site Clearing, Preparation & Site Remediation cost category in Exhibit B, Tab 7, Schedule 1, Table 3 and that the funds have been redistributed for the purpose of comparison in response to JT2.21.
   i. Please identify and define categories of economic participation included in First Nation and Métis Participation and dis-aggregate and itemize the total estimated cost of $18,450,000 shown in response to JT.2.21.
   ii. Please explain the rationale for accounting for the First Nation and Métis Participation costs in the Site Clearing, Preparation and Remediation cost category in Exhibit B, Tab 7, Schedule 1, Table 3.
   iii. Are there any potential participation costs that are not included in the $18 million amount? If so, please explain what they are?

e) Hydro One's estimated costs for Site Clearing and Access are 38% lower than NextBridge's. Hydro One noted that the variance is due to a much smaller environmental footprint.
   i. Please explain why this is the case and how Hydro One's estimates were calculated.
   ii. Please explain why the site clearing costs are substantially lower than NextBridge's even for the HONI-NextBridge "Bypass" Route?

f) Hydro One's contingency is about $10.8 million and is exclusive of $54 million of risk and contingency in the fixed-price EPC contract.
   i. What are the risks categories covered by the $10.8 million contingency?
   ii. What are the risks categories covered by the $54 million contingency in the EPC contract?
   iii. What are the risks that are not covered by the $10.8 million contingency?
   iv. What are the risks that are not covered by the $54 million contingency?

Response:

a) As explained in Exhibit JT2.21, Hydro One does not have detailed information on the NextBridge costs which served as inputs to Table 2. Hydro One's response therefore can provide only Hydro One's beliefs about the variance from NextBridge's costs.

Hydro One's response is based on material only, including tower steel, foundation steel, conductor, wire, hardware and anchors. Equipment used in the construction is included in the separate Construction and Site Clearing, Access categories.

i. Hydro One's tower designs differ greatly from NextBridge's, particularly in the guyed tangent towers, which account for 80% of the towers used in the LSL line: Hydro One's towers were optimized for weight to enable them to be lifted by an erecting helicopter in a single lift. Compared to NextBridge's Y-guyed tangent structures, Hydro One's design keeps the conductors closer to the centreline, enabling a lighter structure and a narrower right-of-way. This design is also optimized for helicopter stringing.
ii. The Hydro One preferred routing is approximately 10% shorter than the NextBridge route, resulting in the use of less material, e.g. number of towers and foundations, length of conductor, OPGW and steel wire.
iii. SNC-Lavalin has developed projects around the world and in so doing has experience in sourcing materials from various countries, enabling preferred pricing due to the volumes and purchasing power from repeated project development.
iv. Given the lack of detailed information on the NextBridge costs, Hydro One is unaware at this time of any other factors.

b) The approximately $58M in materials was estimated through competitive market price RFPs for the materials proposed for the entire project. The quantities were derived from bills of material for the preferred LSL route.

i. All of the $58M amount is part of the fixed price EPC contract with SNC-Lavalin.

c) Hydro One has no knowledge as to how NextBridge developed its estimate. Therefore, Hydro One cannot explain why NextBridge's estimate is much higher. What Hydro One can do is to provide the following information.

i. Hydro One's land rights cost estimate is based on the following components:
   - 113 patented properties wherein Hydro One would acquire fee simple or easement rights, representing less than 30% of the land rights area required. These land rights were estimated using market and injurious affections studies specific to the LSL project and land use types affected. Included in the market value payment are incentive payments set through Hydro One's Land Acquisition Compensation Principles (LACP);
   - The remaining land area requirements, which are greater than 70% of the land rights area required, are to be secured through licences and leases entailing

recurring payments. These payments are in accordance with prevailing rent schedules with MNRF and Parks Canada;

- Business loss/disruption estimate based on an overview of the line and the frequency of occurrence on past projects;
- Land rights within First Nation reserves, which are less than 3% of the land rights area required, are to be secured through permit with annual payments based on market value and payments in lieu of taxes, similar to the existing transmission occupations;
- In support of the land rights acquisitions, the cost estimate includes studies, capacity funding, agent and legal fees, and surveys;
- Temporary rights for off-corridor access and facilities, including storage yards, fly yards and camps.

ii. The route around Pukaskwa National Park would result in approximately 14% additional Crown land area and two fewer impacted parcels. The cost difference is largely for the annual rights payment to the MNRF, which would increase by the equivalent 14% (approximately $10K annually).

iii. Hydro One will be acquiring the following rights (stated costs exclude incentives, capacity funding, agent, legal and surveys):

- Permanent Land Rights lump sum payment (i.e. easements, fees simple, railway crossings and MTO encroachments) - $1,763K
- Permanent Land Rights recurring payments (i.e. MNRF land use permit, Parks Canada licence and First Nation transmission permits)

iv. The acquisition of land rights is based on market and injurious affection studies specific to the LSL project setting and impacted land use types. Included in market value payments are incentive payments from Hydro One's LACP, which provides a significantly greater payment than market, being greater than three times market for the median property. These incentives would be lost to the property owner if expropriation were to occur. Therefore, Hydro One has a high success rate in achieving voluntary settlements: approximately 90% on Bruce to Milton and 100% on both Supply to Essex County Transmission Reinforcement and Barrie Area Transmission Upgrade, which were Hydro One's three most recent major transmission projects.

v. Hydro One has assumed 100% voluntary settlement based on the response to part c) iv) above. The total cost for voluntary settlements is $10,978K.

vi. In its risk assessment, it identified expropriation which was assessed as a low probability. Expropriation has been identified in the Risk Registry and costs have not been included in the Real Estate estimate. The results of Bruce to Milton were considered and adjusted downwards to a total of 10%, or 8 of the impacted patented properties (“IPP”), wherein Hydro One has the ability to expropriate. The cost of expropriation of these properties has been estimated at $2,400K.

vii. based on a construction start of Q3 2019, Hydro One is seeking to achieve all voluntary settlements by May 2019.

d)

i. The cost for Indigenous businesses to execute Site Clearing, Preparation and Site Remediation services has not been disaggregated. This estimate represents a genuine pre-estimate from previous projects and an assessment of capacity for this project. Hydro One will continue to strive to maximize the utilization of Indigenous labour within the construction of the works and does not envisage any material impact on the overall construction price.

ii. Through previous project experience it is understood that Site Clearing, Prep, and Remediation contract opportunities would typically be executed by Indigenous businesses, either on their own or in partnership with other Indigenous or non-Indigenous businesses, which is why the First Nation and Metis participation was accounted for in this category.

iii. No.

e)

i. The difference is due to the ROW space required due to (1) the design and (2) the location when paralleling the existing EWT, as well as (3) the reduction in linear length due to going through Pukaskwa National Park. When comparing designs, the need for ROW width for Hydro One is 150’ compared to the 210’ width that NextBridge says it requires. Hydro One then takes into account the proximity to Hydro One’s existing EWT line, which reduces Hydro One’s 150’ requirement to 120’. Additionally, the Park route reduces the length by 40km.

ii. The site clearing costs are substantially lower even with the bypass route because the Hydro One corridor width is smaller than that of NextBridge, resulting in a diffefence of approximately 450 hectares difference in clearing area.

f)

i. Refer to current Risk Registry, provided at Exhibit I, Tab 5, Schedule 15.

ii. The EPC Contract with SNC-Lavalin covers an extensive scope of EPC work associated with this project, which is detailed in JT2.22 – Appendix A – Scope of Work - Division of Responsibility, however at a high level is outlined for ease below:

a. Project Management and Project Controls for the EPC Project
b. Engineering:
    i. Development and design of structure types
    ii. Selection of centerline and structure spotting on the right of way
    iii. Design of assembly and hardware details
    iv. Geo-technical interpretation and design of foundations
    v. Specifications for procurement of materials
c. Procurement:
    i. Procurement of all materials (e.g. lattice tower steel, conductor, hardware and assemblies, etc.)
    ii. Establishment and administration of all subcontracts for services utilized in the construction of the project
d. Construction
    i. Establishment of temporary facilities associated with the project (e.g. construction person camps, site offices, material laydown yards, fly yards, etc.)
    ii. Establishment of temporary access roads to the ROW
    iii. Clearing and brushing of the ROW
    iv. Construction of the foundations associated with the transmission line
    v. Assembly, erection and stringing of the transmission line
    vi. Restoration and site remediation associated with the de-mobilization of the construction works

In developing a fixed price to cover the scope of works associated with the EPC contract, a risk and contingency allowance is derived to cover differences in quantities, construction execution techniques, variances in production rates, etc., associated with the level of definition at time of bid to those experienced during project execution. Changes to the EPC Contract price will only occur for items that are outside of the scope of the EPC Contract and given the broad and encompassing nature of the EPC Contract between Hydro One and SNC-Lavalin, many of the interface risks between engineering, procurement and construction activities would fall under the scope of SNC-Lavalin. In other project delivery methods chosen by other owners or developers, where there are elements of the engineering and procurement being handled by the owner, the risk of construction costs impacts increases for changes or delays associated with the engineering and material supply, resulting in price adjustments which would be borne by the rate payer

iii. As the Project has progressed, Hydro One has updated its contingency since some risks that were originally anticipated have not materialized and/or some have. The updated contingency estimate for the Hydro One-specific portion of the LSL project is now $5.4M. The risks not currently covered by Hydro One's contingency remain those identified in Exhibit B, Tab 7, Schedule 1, of the prefiled evidence.

iv. Please refer to the response to ii above.

OEB Staff Interrogatory # 11

Reference:

EB-2017-0364 Evidence, Hydro One's Application filed on February 15, 2018, Exhibit B, Tab 7, Schedule 1, Page 1 and 3
Hydro One's Development Cost Estimates

Hydro One stated that the development costs are estimated at approximately $12.2 million and that the forecast is based on an October 2018 approval date.

Interrogatory:

a) Please provide an updated development cost estimate in the event that OEB approval is received by end of November, or December 2018, respectively.

b) Please elaborate how the response in part (a) would change Hydro One's overall project budget and completion date.

c) Does Hydro One have monthly or quarterly development cost estimates including major components? If so, please provide those current estimates.

Response:

Prior to responding to these interrogatories, Hydro One would like to inform the OEB that the Project cost estimate has been updated to reflect current information. Please also note that Hydro One's updated development costs include costs up to the OEB's decision on Hydro One's Leave to Construct application projected for January 2019, whereas in the original application in February, there was a projection of an October 2018 decision on the application.

DEVELOPMENT COSTS

The Project development costs provided at Exhibit B, Tab 7, Schedule 1, have been amended in as follows in Table 1 below:

Table 1 – Development Cost ($ thousand)		
	February 2018	September Update
Real Estate	$3,813	$3,442
Engineering & Design	$2,034	$4,317
Environmental Approvals	$1,949	$4,328
Regulatory & Legal	$1,782	$528
First Nations & Métis Consultation	$983	$1,990
Project Management	$138	$264
Other Consultations	$217	$423
Interest	$100	$195
Overhead	$1,200	$1,485
Total Development	**$12,215**	**$16,972**

These development cost have been updated to account for various changes that have occurred since Hydro One filed its leave to construct application in February of 2018.

Real Estate Costs – Development Phase

Real Estate activities have been progressing favourably, generally in accordance with plan, but slightly behind schedule. The development costs have decreased by ($0.37 million). At the outset, there was an approximate 8 week delay in contracting for field property agent services. In addition there was an approximate 4 week delay in establishing meaningful property owner contacts to launch direct field activities. These delays have contributed to the under expenditures to plan through a delayed offer process.

Engineering & Design Costs – Development Phase

Engineering and Design Development cost have increased by $2.30M due to the Development phase being shifted from previously assumed LTC approval dated October 2018 to the now assumed approval in January 2019. The total Engineering and Design cost, including both Development and Construction phase costs, has increased by ($0.75M) Consequently Construction Management, Engineering, Design and Procurement costs have been decreased in the Construction phase.

The extra work to be done in Development phase encompasses:

- Engineering survey of tower and foundation in Pukaskwa Nation Park
- Engineering work required to initiate geotechnical work in the field
- Engineering work required to define extent of construction permits
- Engineering work required so that firm offers can be obtained for fabrication and testing of tower prototypes.

Environmental Approvals Costs – Development Phase

The increase in Environmental Approvals development costs of approximately $2.4M can be attributed predominately to the following:

- inclusion of some contingency costs in the updated cost, as the risk has been realized, ($150K); and,
- increases in approach to environmental approvals and scope of studies and consultation ($2.2 million).

Contingency costs realized of $150K in the updated cost included additional activities identified as potentially being required based on a very narrow scope of an EA amendment.

Additional costs attributed to changes in approach to environmental approvals and scope of studies and consultation include:

- additional Stage 2 archaeology costs as differences in tower locations between NextBridge and Hydro One designs became evident after additional studies were completed along the route for tower siting
- a portion of the cost of the Parks Canada Detail Impact Assessment. Although either a basic or detailed impact assessment is expected under CEAA, no additional cost was originally included in the budget for this, as Parks Canada indicated they would allow use of Hydro One's provincial EA documentation for review. However, this is now not the case (as conveyed in July 2018 communication letter provided in Exhibit I, Tab 1, Schedule 14) due to the more complicated scope and the addition of the Dorion route in the Hydro One IEA, as outlined in the ToR
- a portion of the cost of the Dorion Route Alternatives. There were changes in the scope of the Declaration Order/EA that resulted from the addition of the Dorion route alternative. This increased costs for consulting, additional meetings, stakeholder consultation, reporting, travel, and various studies (eg., additional visual assessment and

simulation around Dorion, biological, human health, cultural heritage, socio economic etc.)

- a portion of about the cost of conducting an Individual EA Process concurrently with the Declaration Order approach. Based on MECP feedback, the Individual IEA Process has been undertaken in parallel with the Declaration order process. This results in additional costs to cover the IEA process, the ToR, the increased scope and study area and different processes. These cost include additional labour, consulting costs (studies for biological, human health, cultural heritage, socio-economic etc.), disbursements for meetings, consultations, documentation, reporting, travel.

Regulatory & Legal Costs – Development Phase

Regulatory and legal costs have decreased (-$1.3M) as the original budget was based on the assumption that the OEB hearings were going to be held in Thunder Bay, increasing both internal, regulator, and intervenor funding costs. Additionally, with the combined hearing, Hydro One now assumes that the OEB will follow a similar cost sharing approach that was utilized in the NextBridge Motion to Dismiss Hearing where both transmitters will be responsible for funding the procedural costs of the hearing.

Indigenous Consultation Costs – Development Phase

The Indigenous consultation estimate has increased by ($1 million), which is a function of increased consultation given the Environmental Assessment scope has changed from the Declaration order to an Individual EA, as well as risks that have materialized and hence been removed from project contingency. Although the preferred option remains the Declaration order, the additional studies and resources required for an Individual EA have led to an increase in the Indigenous Consultation budget to allow for the Indigenous communities to be meaningfully consulted on the Project, including the EA. Also related to the change in the EA scope, Hydro One is required to meet with 18 Indigenous communities and the Métis on a more frequent basis than originally budgeted for. In addition, the following four Indigenous communities have expressed an interest in the project and Hydro One has engaged them. Métis Nation of Ontario - North Channel Métis Council, Métis Nation of Ontario – Historic Sault St. Marie Council, Jackfish Métis Association, and the Ontario Coalition of Indigenous Peoples. Hydro One is required to consult with any Indigenous community that expresses an interest on the Project, hence the need for additional resources to accommodate the interest of these additional four communities.

Additional costs are also associated with the need for further consultation with two of the First Nations who have a real estate permit interest in the Project. Pays Plat and Michipicoten First Nation have existing on reserve real estate permits that require negotiations which leads to additional costs.

Hydro One's Indigenous Consultation project costs were developed in absence of the delegation letter from the Crown (Hydro One requested it in November 2017 but did not receive until March 2018) with regards to consultation and therefore had to be amended to reflect delegation from the Crown. Hydro One anticipated that the Ministry of Energy would identify the depth of consultation required for each of the 18 Indigenous communities and assumed that the 6 BLP communities would be identified as requiring deeper consultation. Although this is something the Ministry of Energy is required to provide as part of its MOU with Hydro One regarding consultation on projects, the March 2, 2018 delegation letter identified all 18 Indigenous communities as "rights-based" and therefore Hydro One was not provided with depth of consultation required for each community but instead was directed to consult with all Indigenous communities equally. This leads to additional time and costs than what was included in the original Indigenous Consultation estimate.

Project Management Costs – Development Phase

Project Management cost have increased ($0.1M) due to Development phase being shifted from previously assumed LTC approval in October of 2018 to now assumed approval in January of 2019.

Other Consultation Costs – Development Phase

Other consultation costs have increased by $0.2M due to the requirement to consult on the Dorion Route alternative.

Interest During Construction & Overhead Capitalization – Development Phase

Interest during construction and overhead capitalization costs were initially budgeted and spread among the various cost items provided in Table 2 of Exhibit B, Tab 7, Schedule 1. Hydro One has a standard methodology for allocation of interest and applies an overhead capitalization rate to all its projects to account for non-direct staff's time working on capital projects. This overhead rate is determined by spreading a portion of overhead staff across budgeted capital projects. In this update, we have shown both of these numbers as separate line items. The increase in costs ($0.4M) are a function of timing and the increase in the cost update as provided above.

CONSTRUCTION COSTS

The Project costs provided at Table 3 of Exhibit B, Tab 7, Schedule 1 for Project Costs have been amended as follows in Table 2.

Table 2 – Construction Costs ($ thousand)

	February 2018	Sept. Update
Construction	354,030	355,530
Site Clearing, Preparation & Site Remediation	104,339	104,339
Material	58,713	58,713
Project Management	5,802	6,085
Other Costs	9,451	9,451
Construction Management, Engineering, Design & Procurement	17,828	16,304
Real Estate	9,798	10,558
First Nations & Métis Consultations	1,133	3,615
Environmental Approval	819	2,423
Other Consultations	160	30
Contingency	10,775	5,401
Interest During Construction("IDC")	42,596	43,845
Overhead	8,502	8,506
Total Construction Cost	**623,946**	**624,800**

EPC Construction Costs: (Construction; Site Clearing; Material; Other costs; Construction Management, Engineering Design & Procurement)

Construction Management, Engineering, Design & Procurement cost has decreased (-$1.5M) due to Construction phase being shifted from assumed November 2018 to now assumed February 2019 and associated planned costs being allocated to the Development phase.

The overall cost for the fixed-price EPC contract has not changed, across the development and construction phases. Through further development work on the project, it was identified by Hydro One that some relocation costs for the T1M section of line were not included in the total project estimate although they are included in the scope of EA activities. They have since been added into the Construction phase of the project at $1.5 million. Of note, these costs are also not included in the NextBridge application, and should be borne by the transmitter selected to construct the project.

Real Estate Costs – Construction Phase

The cost increase for Construction of $0.8M to the Original Application Estimated is attributable to the delays outlined in the Development Costs rationale for Real Estate above.

Project Management Costs – Construction Phase

Project Management cost in Construction phase have increased slightly ($0.3M) through this phase.

Indigenous Consultation Costs – Construction Phase

Certain costs during the construction phase of the Project have been identified to have increased, such as First Nations and Métis costs and Environmental Approval costs. However, these costs have been off-set by the reduction in Hydro One's contingency costs. The rationale for these increased costs are explained in the section above that deals with development costs.

Environmental Approval Costs – Construction Phase

The increase in Environmental Approval costs during the Construction phase of approximately $1.6 million can be attributed to a number of factors including:

- $890K in contingency costs expected to be realized during the construction phase for post-EA work such as permitting and additional approvals;
- changes in the approach to environmental approvals, scope of studies and consultation as a result of these activities continuing past the LTC date (approximately $714K). These items include: Parks Canada Detail Impact Assessment, Dorion Route Alternatives studies, and conducting the Individual EA Process concurrently with the Declaration Order approach. These additional scope activities are all described in the Development Phase Environmental Approval cost increases above.

Contingency – Construction Phase

Estimated contingency has been reduced (-$5.4M) due to a number of risks being materialized, mostly related to Environmental Approval and Indigenous Consultation. Interest during construction and contingency cost have been updated to reflect the changes in the updated construction costs provided above.

Hydro One's total Project costs are now approximately $642M, an increase of less than 1% from the original filing and still considerably less than the original NextBridge estimate of $777M.

a) An updated development cost estimate is provided as Table 3 of this response. Hydro One now expects that LTC approval will be obtained by the end of January, 2019. If approval is received by end of November or end of December, refer to Figure below for expected development costs.

Table 3 - Life to Date & Forecast Development Cost ($000s)

	Feb 15, 2018 (S.92)[1]	Life to Date (31/08/2018)	End of Sept 2018	End of Oct 2018	End of Nov 2018	End of Dec 2018	End of Jan 2019
Real Estate	3,813	1,235	1,735	2,235	2,735	3,035	3,442
Engineering and Design	2,034	1,277	1,523	2,234	2,798	3,202	4,317
Environmental Approval	1,949	727	1,527	2,327	3,137	3,528	4,328
Regulatory & Legal	1,782	253	303	353	403	453	528
First Nations and Metis Consultations	983	57	357	657	1,157	1,490	1,990
Project Management	138	110	125	161	197	228	264
Other Consultations	217	223	273	323	373	402	423
Interest	100	18	16	25	35	46	195
Overhead	1,200	512	110	235	258	153	1,485
Total Development Cost	**12,215**	**4,412**	**5,969**	**8,550**	**11,093**	**12,537**	**16,972**

b) There would be no change to the overall project costs. Refer to Exhibit I, Tab 4, Schedule 3 for a scenario analysis that assesses the impact of regulatory approval delays will have on total project costs.

c) Please refer to a) above.

[1] Updated to identify interest and overheads separately

OEB Staff Interrogatory # 12

Reference:

EB-2017-0364 Evidence, Hydro One's Application filed on February 15, 2018, Exhibit B, Tab 7, Schedule 1, Page 3
Hydro One's Development Cost Estimates

Hydro One submitted that the development costs of approximately $12.2 million should be eligible for recovery in rate base, if Hydro One is selected to construct the new line.

Interrogatory:

a) Is Hydro One prepared to absorb the cost variances above $12.2 million in the event that the development costs rise over the $12.2 million forecast? Please explain.

b) Using the categories of development costs in "Table 2: Development Costs" in the evidence (Exhibit B, Tab 7, Schedule 1, Page 3), please provide the actual development costs incurred by Hydro One to date.

c) To the extent that actual development costs for any category exceed the amount that Hydro One anticipated that it would have incurred to this point, please explain the reason for each exceedance and steps that Hydro One has taken to mitigate each cost exceedance.

d) Given Hydro One was not the designated proponent at the time of the designation, please explain why in Hydro One's view, ratepayers should pay for any development costs incurred by Hydro One, if Hydro One is ultimately selected by the OEB to build the line.

Response:

a) If granted leave to construct, Hydro One would seek to recover any development over the current estimate of $17.0M that ultimately helps achieve an overall Project that is significantly less expensive than the current $777M alternative proposed by NextBridge. In other words, as described in Exhibit B, Tab 7, Schedule 1, Hydro One would seek approval of its development costs since the benefits significantly outweigh the costs.

b) Please refer to Exhibit I, Tab 1, Schedule 11, part a)

c) The actual LTD cost do not exceed the amount Hydro One anticipated up to this point (Aug 31, 2018)

d) Hydro One's view on why the development costs are reasonably recoverable are articulated at Exhibit B, Tab 7, Schedule 1, specifically, section 1.1.

OEB Staff Interrogatory # 13

Reference:

EB-2017-0364 Evidence, Hydro One's Application filed on February 15, 2018, Exhibit B, Tab 7, Schedule 1, Page 10, Lines 9 to 11

Hydro One in its evidence indicated that it made no contingencies for certain unlikely events and that reasonable price adjustments would be submitted to the OEB for prudence review only after all other resources have been exhausted. Among the unlikely events, Hydro One identified significant changes in costs of materials, commodity rates and/or exchange rates post-October 2018. Hydro One noted that the dollar amount subject to these risks is less than 8% of total project costs.

Interrogatory:

a) Please comment on how likely it is that recent U.S. steel tariffs will significantly impact the estimated costs of materials for the line construction. What is the estimated dollar amount of an increase, if applicable?

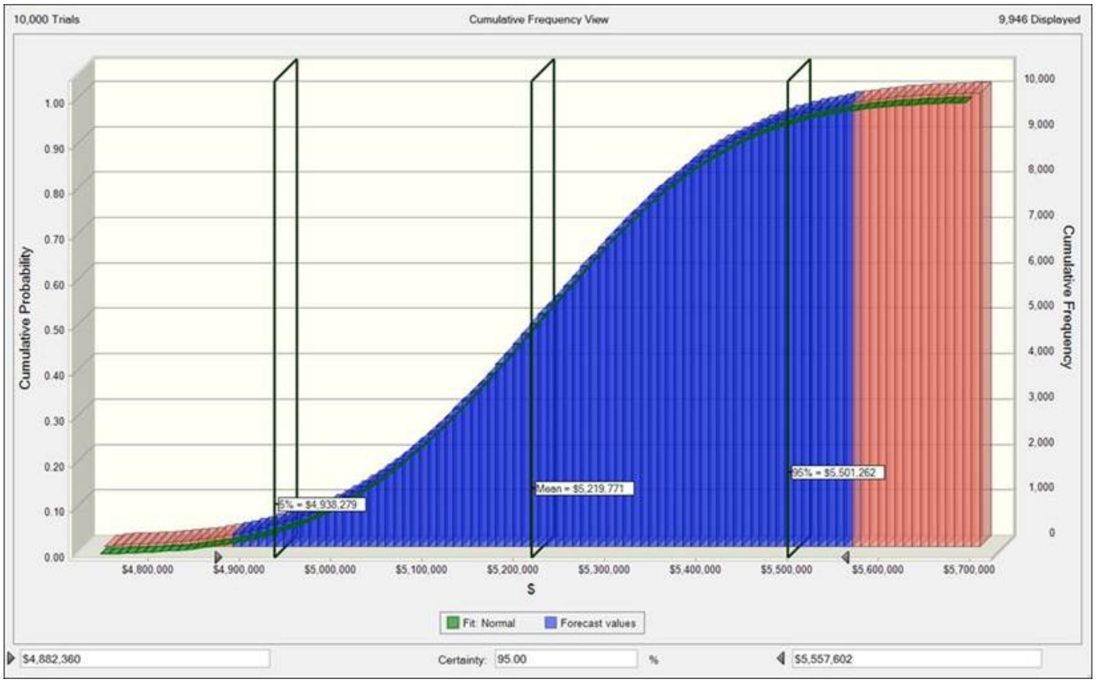
b) Have any of the potential risks identified in Hydro One's LTC applications become more likely to occur, since the filing of its Lake Superior Link application? If yes, please identify those risks and potential costs, should these risks materialize.

c) Has Hydro One found that the contingencies for the project need to be revised, since the application was filed? If so, please describe the costs according to appropriate categories and provide the reasons for any changes.

Response:

a) No impacts from the recent US steel tariffs are expected on the proposed pricing.

b) Please refer to Exhibit I, Tab 1, Schedule 11 where Hydro One's updated cost estimate is provided. In summary, Hydro One's portion of the contingency has changed from $10.8 million to $5.5 million. A portion of the contingency reduction is a function of risks that have materialized and are now included in base-costs (i.e., primarily Environmental Assessment and Indigenous Relations), as well as risks that have changed with additional project development work (such as Real Estate). Please refer to Attachment 1 for Hydro One's updated Risk Registry. The results of the Monte Carlo simulation are provided below.



c) Yes, please see part b) above.

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Lake Superior Link
Risk Register

Risk Counter	Risk Title	Risk Status	Probability Ranking	Cost Impact Estimate	Schedule Impact	Additonal Comments on Cost and Schedule
1	Because this EA Amendment procedure is unprecedented with the MOECC it is unclear at this time if it will be accepted by the MOECC. MOECC may require HONI to begin at a different stage gate in the IEA process (ie new TOR, or new EA). A condition required to proceed; Note risk updated in September 2018 to reduce probability ranking as more clarity around process is now available	ACTIVE	UNLIKELY 25% - 49%		Order of magnitude 2+ years for EA approval	Cost impact initially not carried as would greatly alter working assumptions; now additional cost included in LSL cost update, based on current knowledge of regulatory approval process - assuming Declaration Order or Individual EA using publicly available work from NextBridge; if NextBridge approval/work cannot be referenced then order of magnitude cost is increased by approximately $20M
2	Additional studies, reports and/or consultation, including open houses. September 2018 update: Initially intended for EA Amendment scope. This contingency is now included in the cost, however, approach of Declaration Order and IEA for entire route add additional scope and cost which is now also included in the updated cost.	CLOSED	LIKELY 75% - 94%			Cost incorporated into updated base cost for Enviornmental Approvals
3	Construction delays due to above risk #2; cost included in EPC cost impact due to delays	ACTIVE	LIKELY 75% - 94%			If EA Approval granted later then Aug 2019; need to re-base schedule and cost
4	Additional cost to explore other routing alternatives for Park section. September 2018 update: Initially intended for EA Amendment scope. This contingency is now included in the cost, however, approach of Declaration Order and IEA for entire route add additional scope and cost which is now also included in the updated cost.	CLOSED	VERY LIKELY 95% - 100%			Cost incorporated into updated base cost for Enviornmental Approvals
5	EPC Contractor has to use four circuit towers around Loon Lake / Dorion, refer to above risk #4	Inactive	REMOTE 0% - 24%			
6	EPC Contractor has to make a bypass around Loon Lake / Dorion, refer to above risk #4	CLOSED	VERY LIKELY 95% - 100%			
7	If there is a separate commercial entity (including Hydro One as well as other entities) which will be the owner of the infrastructure within PNP will this affect the license agreement and the ability to consider this as existing infrastructure (ie not a new development)?	ACTIVE	REMOTE 0% - 24%			Potential delays to agreements; not likely cost implications; refer to schedule delay scenarios
8	A large portion of the EA document needs to be rewritten to reflect the design, construction, maintenance and operation practices of Hydro One.	CLOSED	VERY LIKELY 95% - 100%		Incorporated into updated Sept 2018 schedule	Cost incorporated into updated base cost for Enviornmental Approvals
9	Nextbridge IEA was intended to meet the MNRF Class EA requirements for both the disposition of Crown land and works in Provincial Parks. We will need to follow up with the MNRF to confirm that this EA and the subsequent Amendment meet their Class EA requirements. MNRF may require further information or time to conduct further Class EA work of their own.	ACTIVE	EVEN ODDS 50% - 74%		2-3 months delay to start of construction	Risk cost impact combined with risk 10
10	Nextbridge IEA was intended to meet the Ministry of Infrastructures Class EA requirements for the disposition or modification of IO/ORC lands. Nextbridge was to submit additional information to MOI under a separate cover that is not currently in the public realm. There may be no trigger for the Class EA or if there is the MOI may deem the current IEA and additional information provided by Nextbridge inadequate to meet their Class EA requirements.	ACTIVE	LIKELY 75% - 94%	$ 1,000,000	2-3 months delay to start of construction	
11	Schedule impact due to delays under S. 35. (expropriation delaying construction)	ACTIVE	UNLIKELY 25% - 49%	$ 1,000,000	6 month delay	
12	A written plan for construction will need to be submitted per article 8.01 of the current licence agreement. Parks Canada will not approve the modification of the route. A condition required to proceed with base scenario.	ACTIVE	REMOTE 0% - 24%			Risk would result in route around Pukaswka National Park; development costs same
13	Parks Canada Detail Impact Assessment; September 2018 update: Although basic or detailed impact assessment expected under CEAA - no additional cost originally included in budget as Parks Canada indicated they would allow use of existing IEA document. This is not the case, as conveyed in July 2018, due to the more complicated scope and addition of Dorion route in IEA ToR.	CLOSED	LIKELY 75% - 94%		Not a Risk	Cost incorporated into updated base cost for Enviornmental Approvals
14	Analyses, Studies and reports within the EA will need to be amended to reflect the changes in routing and construction practices (such as ROW width, access). Many of these studies are time sensitive and seasons specific. We may need 4 seasons to complete all of the necessary studies. There is also the risk that early access agreements will not be in place to allow for conducting the studies at the appropriate time.	ACTIVE	UNLIKELY 25% - 49%		6 month delay to start of construction	Cost captured in Risk 20
15	Delay in coordinating Indigenous monitors which may be required for various studies including Archaeology and Natural Heritage.	ACTIVE	UNLIKELY 25% - 49%		6 months delay to construction start	Not likely a significant additional cost, only affects schedule and any resulting costs from schedule delay

Lake Superior Link
Risk Register

Risk Counter	Risk Title	Risk Status	Probability Ranking	Cost Impact Estimate	Schedule Impact	Additonal Comments on Cost and Schedule
16	The reaction by Indigenous communities to additional consultation from Hydro One is uncertain. Indigenous communities may be limited in the extent they can share information with Hydro One given existing agreements with Nx. (Cost Incorporates risks 26-29)	ACTIVE	EVEN ODDS 50% - 74%	$ 1,000,000	6-12 month delay to construction start	
17	If leave to construct is awarded to Hydro One and NxB EA is not complete there is a risk of NxB not completing the EA.	ACTIVE	EVEN ODDS 50% - 74%		6 months delay to construction start	Cost implications difficult to determine, as it is not clear if portions of NextBridge work may be utlized by Hydro One; refer to Risk 1
18	Indigenous monitors may need to be present for Geotechnical studies.	ACTIVE	VERY LIKELY 95% - 100%		3-6 month delay to construction start	Cost risk captured in Risk 15
19	Permits for such things as water crossings, roads, tree clearing etc. may run into delays or added costs depending on availability and requirements of Regulatory staff and other stakeholders (ie Sustainable Forest Licencees).	ACTIVE	EVEN ODDS 50% - 74%	$ 1,200,000	(3-6 month delay)	
20	There is a risk that various environmental features may delay, post-pone or constrain construction activities by imposing timing restrictions. Eg. Species at Risk, nesting birds, water crossings, wet terrain. May also result in unplanned studies or mitigation.	ACTIVE	LIKELY 75% - 94%		SNCL Risk	
21	Stage 2 Archaeology, Cultural Heritage Evaluation Report and Heritage Impact Assessment may have findings that could result in additional studies (such as Stage 3 or 4 archaeological investigations) if mitigation or avoidance is not possible.	ACTIVE	EVEN ODDS 50% - 74%		Exclude from risk model and capture in S92 conditions	
22	Archaeological findings may cause delays to construction and modification to construction access routes or structure locations. Archaeology may not be fully complete before construction begins and may result in the adjustment to construction staging. May cause delays which may result in CCN's.	ACTIVE	EVEN ODDS 50% - 74%		Exclude from risk model and capture in S92 conditions	
23	Requirement for clearance letters from MTCS can cause delays by slow turn around.	ACTIVE	REMOTE 0% - 24%	$ 600,000	1-2 month delay in construction start	
24	Environmental Monitoring commitments made in the IEA and required by Regulator Permits may result in added analysis, studies and reports (ie Turbidity and Total Suspended Solids at water crossings).	ACTIVE	LIKELY 75% - 94%		SNCL to take on risk of construction delays	
25	POST EA Work During and Post Construction may be higher than anticipated	CLOSED	VERY LIKELY 95% - 100%			Cost incorporated into updated base cost for Enviornmental Approvals
26	Indigenous communities may decide to remove themselves from the consultation process, which can affect the consultation budget.	ACTIVE	REMOTE 0% - 24%		combine with 15	Risk cost captured in Risk 15
27	Indigenous communities may request additional meetings in order to conclude the consultation process which can delay necessary approvals and affect the consultation budget	ACTIVE	REMOTE 0% - 24%		combine with 15	Risk cost captured in Risk 15
28	Indigenous communities may raise issues that Hydro One cannot respond to and must be addressed by the Crown, which can delay necessary approvals and affect the consultation budget.	ACTIVE	REMOTE 0% - 24%		combine with 15	Risk cost captured in Risk 15
29	Additional Indigenous communities may assert rights in the Project area and request to be consulted which can delay necessary approvals and affect the consultation budget.	ACTIVE	REMOTE 0% - 24%		combine with 15	Risk cost captured in Risk 15
30	The risk of the regulatory approval taking longer than anticipated and not having visibility on when the EA approval will be received	ACTIVE	LIKELY 75% - 94%			If EA Approval granted later then Aug 2019; need to re-base schedule and cost
31	Land Value Study results lower than individual full narrative property appraisals.	CLOSED	UNLIKELY 25% - 49%			Risk materialized; cost impact ($500K) reflected in revised base budget
32	Property owner delayed authorisation or refusal to grant access for studies and assessments prior to s.92 approval.	ACTIVE	REMOTE 0% - 24%		minimal schedule impact	
33	Refusal to grant option for permanent lands rights, necessitating e	ACTIVE	EVEN ODDS 50% - 74%	$ 2,400,000	nil	Construction can be managed around the 14-18 months expropriation process, without impacting I/S
34	Compensation for Business Disruption/Loss associated in the grant of permanent land rights.	ACTIVE	UNLIKELY 25% - 49%	$ 800,000		

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Lake Superior Link
Risk Register

Risk Counter	Risk Title	Risk Status	Probability Ranking	Cost Impact Estimate	Schedule Impact	Additonal Comments on Cost and Schedule
35	Underlying rights within Provincial Crown lands, e.g. minerals (consent approval).	ACTIVE	EVEN ODDS 50% - 74%	$ 500,000		
36	Project requirements for route result in impact to primary residence or major out building (Buyout/Relocation).	CLOSED	UNLIKELY 25% - 49%			Risk materialized; cost impact reflected in revised base budget
37	Obtaining agreement and associated permits from FN (Pays Platt and Michipicoten) to accept current rental formula with other FN (annual amount).	ACTIVE	LIKELY 75% - 94%			Cost impact, if materialized is on OM&A
38	Undefined access road for temporary requirements (relying on preliminary information).	ACTIVE	LIKELY 75% - 94%	$ 525,000		
39	Unable to procure necessary Land Agent resources in a timely manner (substitute with internal staff).	ACTIVE	REMOTE 0% - 24%	$ 260,000		
40	Real Estate Buyouts found in the last moment (already addressed within Risk 36).	CLOSED	VERY LIKELY 95% - 100%			Risk materialized; cost impact reflected in revised base budget
41	IESO may reject the 15 days double circuit outage as it does not consider it as a valid plan	CLOSED	REMOTE 0% - 24%			
42	15 days double circuit outage cancelled two weeks before scheduled start date. New start date moved to following year.	ACTIVE	REMOTE 0% - 24%	$ 5,000,000		
43	15 days double circuit outage delayed for one week, 1 day before original scheduled start date.	ACTIVE	REMOTE 0% - 24%			
44	Single circuit outage(s) start delayed four hours in the morning of starting daily outage ($100k per instance)	ACTIVE	EVEN ODDS 50% - 74%	$ 600,000		
45	Communication cost due to POST EA Work During and Post Construction may be higher than anticipated	ACTIVE	VERY LIKELY 95% - 100%	$ 300,000		
46	Risk that Indigenous Communities request more than industry-typical study scopes	ACTIVE	EVEN ODDS 50% - 74%			Cost risk captured in Risk 15
47	MECP does not approve NxB EA by end of Q4 2018 as anticipated	ACTIVE	VERY LIKELY 95% - 100%			Result is delay and associated cost as described in Risk 30
48	MECP does not approve NxB at all and transfers all issues to H1	ACTIVE	EVEN ODDS 50% - 74%			Similar implications to Risk 17: Cost implications difficult to determine, as it is not clear if portions of NextBridge work may be utlized by Hydro One; refer to Risk 1
49	HONI is not granted Dec order, CEAA approval by August 15/19	ACTIVE	EVEN ODDS 50% - 74%			Result is delay and associated cost as described in Risk 30
50	Delay to project due to MECP tying Station EA approval to Dec order/IEA approval for LSL	ACTIVE	EVEN ODDS 50% - 74%		Current Jan 2019 EA approval as expected maintains in-service date of Dec 2021	Delay beyond that in assumptions will result in delay and associated cost as described in Risk 30