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Joanne Richardson
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Regulatory Affairs

BY COURIER

May 23, 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-2018-0098 – Hydro One Networks Inc.'s Section 92 - Kapuskasing Area Reinforcement Project – Interrogatory Responses

On February 5, 2018, Hydro One Networks Inc.'s ("Hydro One") filed an Application pursuant to Section 92 of the Ontario Energy Board Act for an Order or Orders granting leave to upgrade existing transmission line facilities in the municipalities of Kapuskasing, Moonbeam, Fauquier-Strickland, and Smooth Rock Falls.

On April 23, 2018, the OEB issued Procedural Order No. 1, outlining steps for written interrogatories and directing Hydro One to file written responses by May 23, 2018. With this letter, Hydro One is now filing its written responses.

The responses have also been filed through the Ontario Energy Board's Regulatory Electronic Submission System (RESS).

Sincerely,

ORIGINAL SIGNED BY JOANNE RICHARDSON

Joanne Richardson

OEB Board Staff Interrogatory # 1

Description of Need

Reference:

Ex. B/Tab. 3/Schedule 1, pg. 4

Interrogatory:

Preamble:

Hydro One's evidence states:

This project is required to address capacity and voltage performance needs that emerge due to the expiry of local generation facilities' contracts. Once the contracts expire, these generation facilities can no longer be relied on to meet local needs. The project need date is June 2020.

a) Please confirm the contracts expiry date is June 2020. Is there a provision within the agreement for emergency service past the contract expiry date?

b) Did the IESO considered negotiating a new long term supply contract with the generator at the existing supply level? If not why not? If this alternative was considered, please explain why it was rejected.

Response:

a) The contract with Kapuskasing GS expired on December 31, 2017 and the contract with Calstock GS will expire on June 17, 2020. These contracts are held by the OEFC and are confidential, therefore the IESO is unable to comment on whether there is a provision for emergency service past the contract expiry date.

b) As part of the assessment, the IESO explored the option of extending Kapuskasing GS or Calstock GS to address the capacity and voltage performance needs that emerge due to the expiry of those generation facilities' contracts. This was Option #3 on page 6 of Exhibit B, Tab 3, Schedule 1, Attachment 1. However, due to the significant cost difference between the transmission option and the option to extend the operation of the NUGs, the IESO decided that it was not necessary to reach out to the NUGs in the Kapuskasing area to further explore the option.

OEB Board Staff Interrogatory # 2

The Recommended Project

Reference:
Ex. B/Tab. 3/Schedule 1, pg. 6, Ex. B/Tab 6/Schedule 1, pg. 1

Interrogatory:
Preamble:

On page 6 of Exhibit B, Tab 3, Schedule 1, Attachment 1, Section 4, the IESO recommends that circuit H9K between Carmichael Falls JCT and Spruce Falls JCT be upgraded to a minimum of 310 A, whereas on page 1 of Exhibit Tab 6, Schedule 1, Hydro One indicates the thermal limits on the circuit will be increased to a minimum summer continuous rating of 370 A.

a) Please explain the apparent discrepancy between the two ratings. Please confirm Hydro One is proposing to upgrade the circuit beyond the IESO's recommended rating.

b) If Hydro One is proposing to upgrade the circuit to 370 A, what is the cost impact over the IESO recommended upgrade rating of 310 A?

Response:
a) The letter from the IESO to Hydro One indicated a requirement to increase the capability of the subject line section to provide a continuous summer rating of at least 310A, <u>and up to 370A</u>. Please refer to Attachment 1 of this interrogatory response. The direction is specifically captured in bullet 3 on page 2 of the attachment. Hydro One will increase the capability to meet a continuous rating of 370A in accordance with the directive.

b) The 411ACSR conductor that Hydro One is using to achieve the thermal increase requested by the IESO is the same conductor it would use to satisfy either a 310A or 370A requirement. There is no cost increase as a result.

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April 13, 2016

Mr. Bing Young
Director, System Development
Hydro One Networks Inc.
483 Bay Street
Toronto, Ontario M5G 2C9

Dear: Bing

Re: Bulk System Reinforcement for the Kapuskasing Area

Background

On September 1, 2015, the IESO published the NUG ("Non-Utility Generator") Framework Assessment report ("NUG Report") to the Minister of Energy. This report identified that following the contract expiry of Kapuskasing Customer Generating Station ("CGS") and Calstock CGS, local reliability standards may not be met without further reinforcement. The NUG Report also indicated that the North/East of Sudbury regional planning study would begin immediately.

Since September 2015, the IESO has been working jointly with Hydro One to assess the local issues identified in the NUG Report. This included initiating the North/East of Sudbury Regional Planning process on September 24, 2015. Based on the fact that there were existing challenges in operating the bulk transmission system in the area, the IESO and Hydro One agreed that a bulk system study should be run in parallel with the formalized Regional Planning Process. This enabled the bulk system study to be expedited to ensure timely solutions are in place given the potential lead time for transmission based solutions.

The scope of the bulk system study for the Kapuskasing area investigated the adequacy and operability of the system supplying the area, as it currently exists, and following the contract expiry of generation facilities Kapuskasing CGS and Calstock CGS.

In accordance with the formalized Regional Planning Process, the Hydro-One led Needs Assessment process was conducted in parallel and assessed needs driven by customer growth. The Needs Assessment process concluded that the bulk system planning process and local planning process are most appropriate to address all the potential needs for the North/East of Sudbury region, and that there is no need for further review of this issue in the formal Regional Planning process.

Summary of Needs from the Bulk System Study

The Ontario Resource and Transmission Assessment Criteria ("ORTAC"), applicable operating limits, and market rules were used to assess the performance of the system. The ORTAC specifies maximum continuous voltage limits of 250 kV and 127 kV for nominal 230 kV and 115 kV system facilities, respectively. There are also some individual stations that have different operating limits than specified by ORTAC. The joint IESO-Hydro One team has identified that maximum voltage limits specified by ORTAC and some specific operating limits would be exceeded for the existing system during outages and system restoration. Respecting voltage limits is of critical importance for the safe and reliable operation of the power system. Therefore there is a need to install facilities to control voltages to within acceptable limits irrespective of the contract status of Kapuskasing CGS and Calstock CGS.

Should it not be possible to rely on the firm capacity of Kapuskasing CGS and Calstock CGS in the future, load customers would be supplied from additional power transfers into the Kapuskasing area through the provincial transmission system. In order to enable these greater transmission flows, there is a need to reinforce a section of circuit H9K and to provide additional voltage support in the area.

The study also found that during periods of high output from hydroelectric generation in the area, records indicate that circuit H9K has been binding and has resulted in congestion. Analysis indicates that this situation is expected to continue in the future. Therefore, reinforcement of circuit H9K is also expected to provide the added benefit of reducing congestion.

Requirement for Transmission Facilities

Based on technical and economic analysis performed by the IESO, and planning-level cost estimates received from Hydro One on February 24, 2016, the facilities outlined below are the least cost options for providing required levels of reliability, voltage performance, efficiency and operational flexibility, and must be placed in-service prior to June 2020.

1. Install a Programmable Synchrocheck Relay at Kapuskasing TS to enable breaker L21L38 to make the parallel between circuits K38S and L21S. This work is required to address existing energization needs.

2. Install a 10 Mvar (at 120 kV) reactor at the Kapuskasing 115 kV bus. To maintain required voltage levels during contingencies, this reactor must be capable of being disconnected from the 115 kV system by a cross-tripping scheme triggered by the loss of circuit L21S. This work is required to address existing energization needs, and outage conditions.

3. Increase the capability of circuit H9K between Carmichael and Spruce Falls (30 km) to provide a continuous summer rating of at least 310 A, and up to 370 A. This work is required to cover the risk of not being able to rely on the firm capacity of Kapuskasing CGS and Calstock CGS, and is also justified based on reducing congestion.

4. Install one 10 Mvar (at 120 kV) capacitor bank at the Kapuskasing 115 kV bus. This capacitor must be capable of being disconnected from the 115 kV system by a cross-

tripping scheme triggered by the loss of Spruce Falls transformer T7. This work is required to cover the risk of not being able to rely on the firm capacity of Kapuskasing CGS and Calstock CGS. If feasible, this work should include space provisions for the installation of a second future 10 Mvar capacitor bank at Kapuskasing 115 kV bus.

Please inform us of the planned in-service dates and the ultimate disposition of work, based on your scoping and project development work. We look forward to working with Hydro One in the related Connection Assessment and Approval (CAA) process for this work when your plans are finalized.

The IESO would be pleased to provide Hydro One with any required assistance in approvals processes associated with these facilities.

Yours truly,

Joe Toneguzzo
CC:
George Pessione, IESO
Ahmed Maria, IESO
Leonard Kula, IESO
Ibrahim El-Nahas, HONI

OEB Board Staff Interrogatory # 3

Alternatives

Reference:

Ex. B/Tab. 3/Schedule 1, Attachment 1, section 5, pg. 8

Interrogatory:

Preamble:

The IESO's evidence states:
Based on the above, Option 1 was determined to be the least-cost option for meeting the capacity and voltage performance needs in the Area.

Additionally, Option 1 is preferable to a new generation facility because any new generation facility would only be required to meet the need for the 10 to 15-year interim period between contract expiry of local generation facilities and the end-of-life replacement of the 32 km section of circuit H9K. This period is shorter than a typical contract period for a similar new facility.

a) How would the cost of signing a short term supply agreement (e.g. 5 years with the existing generator), thus reducing the advancement cost, compare to Option 1? Please provide a cost estimate for this type of solution.

Response:

a) To respond to this interrogatory, the IESO completed additional analysis, and the estimated the cost on a NPV basis for a 5-year contract is more than $36 million. This is because the fixed costs associated with re-configuring the existing facilities to become quick start, including existing asset overhaul and/or replacement, would still have to be recovered, just over a shorter period of time.

   To meet the local area reliability need, it is also possible to continue to operate the existing generators as they are operated today (i.e. not reconfiguring the existing facilities to become quick start). However, if the units are not reconfigured to have a faster start-up time, the units will have to run as baseload generators to ensure they are available when needed, which would result in high energy costs. The IESO estimates that extending the contract with the existing facilities without reconfiguring the facility to become quick start, and assuming baseload generation of 10MW for a 5 year term, would still cost more than $35 million.

The NPV of the cost to advance the upgrades to the 32-km section of H9K by 5 to 10 years and install a capacitor bank is approximately $4.4-6.4 million.

In total, the cost of this new option to sign a short term 5 year agreement, advance the H9K replacement by only 5 to 10 years (instead of the original 10 to 15 years), and install a capacitor bank at the end of the contract term with the existing generators is more expensive than Option 1.

OEB Board Staff Interrogatory # 4

Project Classification and Categorization

Reference:

Exhibit B/Tab. 4/Schedule 1, pg 1, line 23; pg. 2, line 14

Interrogatory:

Preamble:

Hydro One's evidence states:

The Board's filing guidelines require that projects be categorized to distinguish between a project that is a "must-do", which is beyond the control of the applicant ("non-discretionary"), from a project that is at the discretion of the applicant ("discretionary")…Based upon the above criteria, the Project is considered non-discretionary.

a) If the IESO manages to sign a new short term agreement with the existing generator, would the project shift to being "discretionary" during the length of the new short term agreement?

Response:

a) Yes, the project would shift to being discretionary for the length of the new contract and then would become non-discretionary after the contract expires.

As provided in response to Board Staff 6b, even if one or both of the NUGs would clear the incremental capacity auction that the IESO is presently designing, the date of the first capacity auction is still being determined and the current forecast from the Long Term Energy Plan indicates a need for incremental capacity to emerge in the mid-2020s.

Hydro One does not believe that a short-term agreement would therefore materially differ these assessments. Moreover, Hydro One does not believe the Project should be considered discretionary based on a short term agreement, nor that a short term perspective would be prudent to assess the need for this Project.

OEB Board Staff Interrogatory # 5

Apporting Project Cost & Risks

Reference:

Exhibit B/Tab. 7/Schedule 1, Table 1

Interrogatory:

a) Hydro One has estimated the contingency cost to be $700,000, which is 4.6% of the total cost for the line work of $15,065,000. How did Hydro One establish that $700,000 is an appropriate contingency amount? What is the contingency amount for station work?

b) Why did Hydro One not break down the station work into cost components similar to how the line work is presented? E.g. Materials, Labour, Overheads, etc. Please provide the cost breakdown similar to how the line work is presented in Table 1.

Response:

a) The project contingency was calculated by using Hydro One's risk model (monte carlo risk analysis) for projects >$10M. The project team identifies project risks and the probability of the occurrence of those risks by relying on their previous experience with similar type projects. The model then uses that information as initial inputs into a simulation, along with a "Probability Ranking Matrix" and a "Cost Impact Matrix" to come up with the expected contingency amount. The project risks are continually monitored by the Project Manager and the project team for any changes/updates to the contingency forecast. Any necessary changes to the risk register (i.e., close off any risks that did not materialize and have since passed, addition of new risks that were not originally identified, changes to the probabilities of each risk given new information available, etc.) will be re-run through the model to come up with a revised contingency forecast figure as the project progresses.

b) The cost breakdown of the estimate for both station items is provided below. This was missed in the prefiled evidence.

	Estimated Cost ($000's)
Materials	1,927
Labour	1,269
Equipment Rental & Contractor Costs	1,466
Sundry	38
Contingencies	470
Overhead [1]	580
Allowance for Funds Used During Construction [2]	250
Total Station Work	**$6,000**

[1] Overhead costs allocated to the project are for corporate services costs. These costs are charged to capital projects through a standard overhead capitalization rate. As such they are considered "Indirect Overheads". Hydro One does not allocate any project activity to "Direct Overheads" but rather charges all other costs directly to the project.

[2] Capitalized interest (or AFUDC) is calculated using the Board's approved interest rate methodology (EB-2006-0117) to the projects' forecast monthly cash flow and carrying forward closing balance from the preceding month.

OEB Board Staff Interrogatory # 6

Risks and Contingencies

Reference:
Exhibit B/Tab. 7/Schedule 1, pg. 2

Interrogatory:
Preamble:

Hydro One has identified the top three project risks as: Resource shortage, Outage constraints, and Aggressive timelines.

a) Why does Hydro One not consider weather as a potential risk factor, considering the geographical location of the proposed work?

b) Is there a risk that the IESO could pursue a supply option after the project has been initiated, therefore making this project unnecessary? Please elaborate.

Response:
a) Weather was identified and considered as a risk factor for specific portions of the work that are weather-dependent. This risk was incorporated in the overall statistical risk analysis and contingency calculation, but was not one of the top three risks.

b) Once the project has been initiated and completed, the IESO would not be able to extend the contract with the non-utility generators (NUGs) due to the December 14, 2015 and December 16, 2016 directives to the IESO from the Minister of Energy, which collectively direct the IESO to:

   1.1 “Subject to paragraphs 1.4 and 1.5 below, discontinue negotiations for New Contracts for NUGs.

   1.2 Continue engaging stakeholders, including NUG representatives as relevant, in IESO'S development of an Ontario capacity auction, and rules and protocols for Ontario-based capacity exports.

   1.3 Continue to consider NUGs as options to maintain regional reliability.

1.4 Enter into negotiations with the OEFC NUGs regarding a new IESO Contract to change the incentive structure for supplying electricity or capacity so that the facilities operate in a manner that better aligns with the integrated power system's needs and that would satisfy all of the following requirements:

1.4.i Expected cost and operability benefits for the Ontario electricity system are greater than the cost and operability benefits afforded under the current OEFC Contract;

1.4.ii All IESO obligations under the IESO Contract end no later than the date on which the current term of the existing OEFC Contract expires

1.5 The IESO is not required by this direction to enter into an IESO Contract with an OEFC NUG where the IESO is unable to reach agreement with the OEFC NUG on terms that satisfy the requirements set out in paragraph 1.4 of this direction."

Although the IESO cannot extend the contracts with the NUGs, it is possible that one or both of the NUGs would clear the incremental capacity auction that the IESO is presently designing. This, however, would not make the project unnecessary because, although, the date of the first capacity auction is still being determined, current forecasting from the Long Term Energy Plan indicates a need for incremental capacity to emerge in the mid-2020s. This would result in a continued need for the project between the time of contract expiry in 2020 and the commitment time of a capacity auction.

OEB Board Staff Interrogatory # 7

Costs of Comparable Projects

Reference:
Exhibit B/Tab. 7/Schedule 1, page 3, line 9

Interrogatory:
Preamble:

Hydro One's evidence states:
The comparable lines project, D2L Dymond x Upper Notch Junction was a line refurbishment project from Dymond TS to Upper Notch JCT Structure 261.

a) Is the D2L Dymond X Upper Notch Junction the only comparable recent line project that Hydro One has completed within the last 10 years? Please provide the data for two other line project comparables, if available.

b) What other station projects, similar to the 10 MVAR reactive and 10 MVAR capacitive projects have been completed recently by Hydro One? Please provide a comparative cost breakdown for these projects.

Response:

a.) The table below provides two additional reference projects for comparison purposes.

Project	**H9K - Spruce Falls Jct X H9K STR 127A Junction Line refurbishment**	**D2L Dymond x Upper Notch Junction Line refurbishment**	**A6P Reserve Jct x Port Arthur Line refurbishment**	**P3S & P4S (combined) Port Hope Jct x Sidney TS Line refurbishment**
Technical	115kV Wood Pole Single Circuit 411kcmil conductors 7#8 alumoweld shieldwire	115kV H-Frame Wood Pole Single Circuit 477kcmil conductors 7#10 alumoweld shieldwire	115kV H-Frame Wood Pole Single Circuit 411kcmil conductors 7#5 alumoweld shieldwire	115kV H-Frame Wood Pole Single Circuit 732 kcmil conductor 7#7 alumoweld shieldwire
Length (circuit km)	32	42	73.7	60
Project Surroundings	Rural	Rural	Rural	Rural
Environmental Issues	None	None	None	None
In-Service Date	Oct-19	Aug-17	Dec-12	Jul-11
Total Project Cost	$15,200k	$16,000k	$24,000k	$20,000k
Less: Non-Comparable Costs (extra no. of wood poles	$1,240k			
Less: Non-Comparable Costs (multiple river crossings, access, etc.)	$960k			
Add: Escalation Adjustment (2%/year)		$646k	$3,011k	$2,697k
Total Comparable Project Costs	$13,000k	$16,646k	$27,011k	$22,697k
Total Cost/Circuit km	$402k	$396k	$366k	$378k

b.) Hydro One has not been able to complete a comparative estimate for a station project with the exact same undertaking. However, Hydro One can provide that it connected two 12MVar shunt reactors at Basin TS in May of 2013 for $7.6M. Given the smaller scale of this work, the $6M estimate originally provided is reasonable.

OEB Board Staff Interrogatory # 8

Line Physical Design

Reference:

Exhibit C/Tab. 1/Schedule 1, pg. 3

Interrogatory:

Preamble:

Hydro One's evidence states:
As documented, the 115kV H9K in the above sections is strung on wood poles. The existing conductor is 4/0 ACSR. The proposed 411.4kcmil ACSR/TW conductor is heavier and larger in diameter than 4/0 ACSR therefore some structures will need to be replaced to maintain adequate clearance. Additionally, some of the existing pole structures are in bad condition and need to be replaced.

a) What is the number of total poles in the 32 km of circuit H9K that Hydro One is proposing to replace? Is Hydro One proposing to replace all poles in the circuit? If not what percentage of poles will be replaced?

b) Has Hydro One completed engineering calculations to ensure that any remaining poles that are marginally fit poles have sufficient strength to hold up under heavy ice and snow loading?

Response:

a) Hydro One is proposing to replace about 270 of the 310 pole structures.

b) The remaining poles were replaced as part of the Wood Pole Replacement Program and have sufficient strength to take the loading of the new conductors and will hold up under heavy ice and snow loading.

OEB Board Staff Interrogatory # 9

Land Matters

Reference:

Exhibit E, /Tab 1/Schedule 1, pg.1

Interrogatory:

Preamble:

Hydro One's evidence states:

The existing transmission corridor crosses an estimated 104 parcels of land, which consists of:

- Hydro One fee simple ownership;
- Easement corridor over privately-owned and municipally-owned properties;
- Lands under the jurisdiction of the Ministry of Natural Resources and Forestry, which Hydro One holds a Master Land Use Permit for its transmission and distribution facilities;
- Crossings over highways under the jurisdiction of the Ministry of Transportation; and,
- Crossings over railways.

The proposed transmission facility work is not expected to have any impact on the rights of any adjacent properties.

a) Has Hydro One approached any landowners to date? Have any landowners expressed any concerns with the proposed project and routing and, if so, please explain?

b) Has Hydro One approached any landowners that will be impacted by temporary access rights to be used for construction staging, access, flagging and permitting? Have any of these landowners expressed any concerns with the temporary access rights? Will the temporary access rights require any environmental approvals? If so, please explain.

c) Will temporary access rights for construction staging involve any First Nations' lands?

d) Please confirm whether or not Hydro One intends to commence any construction work on the project prior to the completion of all land-related negotiations?

Response:

a) Hydro One sent notifications to over 2,000 landowners and residents located along and adjacent to the transmission line corridor during the Class Environmental Assessment (EA) process. To date, no landowners have expressed concerns with the proposed project.

b) Hydro One has not approached any landowners regarding the temporary access rights that are to be used for construction staging, access, flagging and permitting, as these have not yet been finalized. Once these details are finalized, impacted landowners will be contacted and any necessary agreements will be completed in accordance with the forms provided as Attachments in Exhibit E, Tab 1, Schedule 1. This is not atypical for this type of project.

Hydro One will obtain work permits from the Ministry of Natural Resources and Forestry (MNRF) for water crossings required for construction equipment access along the transmission line corridor. Hydro One consulted with the MNRF during the Class EA process regarding these work permits. No concerns were identified by the MNRF.

c) No temporary access routes or construction staging areas will be located on First Nations reserve lands.

d) Prior to the commencement of construction Hydro One will have all necessary consent and permissions obtained from the impacted property owners.

OEB Board Staff Interrogatory # 10

Land Matters

Reference:
Exhibit E, Tab 1, Schedule 1, Attachments 1 & 2, Forms Of Land Agreements

Interrogatory:
Preamble:

Hydro One's evidence states:
Copies of Off-Corridor Temporary Access and Temporary Access Road, Construction License Agreement for construction staging, and a Damage Claim Agreement and Release Form (which will be used as the basis for compensation related to construction impacts, such as crop or property damage) are included at the end of this schedule as Attachments 1 through 3

a) Please confirm that all of the affected property owners had the option to receive, or will receive the option of, independent legal advice regarding executing the Land Agreements in Attachments 1 through 3 of Exhibit E. What is the current status of these agreements?

b) Please describe the status of any permits that need to be updated with government ministries and railways for the proposed construction and stringing activities.

Response:
a) The affected property owners will have the option of receiving independent legal advice regarding the Land Agreements.

b) Permits are required from the Ministry of Natural Resources and Forestry (for water crossings), Ministry of Transportation Ontario (Encroachment Permit for work within the limits of Highway 11) and Ontario Northland Transportation Commission for the proposed construction activities. Though applications for these work permits have not yet been submitted, approvals should be received well within the time required to achieve the schedule outlined in Exhibit B, Tab 11, Schedule 1 of the Application.

OEB Board Staff Interrogatory # 11

Project Schedule

Reference:
Exhibit B/Tab. 11/Schedule 1, Construction and In-Service Schedule

Interrogatory:
a) Please update the Project Schedule at the above reference if the schedule has changed.

Response:
a) The schedule has not changed.

OEB Board Staff Interrogatory # 12

System Impact Assessment

Reference:

Exhibit. F/Tab. 1/Schedule 1, System Impact Assessment (SIA)

Interrogatory:

Preamble:

Hydro One's evidence states:

Hydro One confirms that it will implement the requirements noted by the IESO in the SIA regarding the 32km line stretch from Spruce Falls to Carmichael Falls. Consistent with the IESO Evidence in Support of Need (provided in Exhibit B, Tab 3, Schedule 1, Attachment 1), there is no longer an identifiable need to complete the 0.3km stretch of line from Gemini Falls to H9K Structure and Hydro One will not be carrying out this work. There is no anticipated system impact.

a) Did the IESO issue an addendum to the SIA to indicate that the 0.3 km stretch of line from Gemini Falls to H9K Structure is no longer needed?

Response:

a) The IESO confirmed that an addendum to Hydro One's SIA CAA 2016-EX866 H9K-Conductor Upgrade is not required.

OEB Board Staff Interrogatory # 13

Cost Responsibility

Reference:

Exhibit. B/Tab. 9/Schedule 1, Rate Impact Assessment, Network Pool

Interrogatory:

Preamble:

Hydro One's evidence states:

Over a 25-year time horizon, this slight change in the network pool revenue requirement is not material enough to incrementally impact the Provincial Network rate, which was assessed at the approved $3.59/kW/month. The maximum revenue shortfall related to the proposed network facilities will be $1.53 million in the year 2026. The detailed analysis illustrating the calculation of the incremental network revenue shortfall and rate impact is provided in Table 1 below.

a) Table 1 indicates a shortfall for the entire 25 year time horizon ranging from $1,043 M in year 2020 to a maximum in 2026 of $1,529 M, to $1,273 M in 2044. This represents a negative balance over the entire 25 year time horizon. How does Hydro One plan to recover this shortfall in 2020 and beyond?

Response:

a) Hydro One notes a correction in the question; Table 1 indicates a shortfall ranging from $1,043k in year 2020 to a maximum in 2026 of 1,529k to $1,273k in 2044, not millions.

   As communicated in Exhibit B-9-1 under Section 2.0 Cost Responsibility (page 2 of 7), the project is "a system project and not tied to any load increase or customer load application", therefore the total project cost is forecast to be included in Hydro One's rate base. Hydro One Transmission will seek recovery of costs associated with this project at a future rate application. The impact of the additional capital expenditures, offset by new revenues, will not have a material rate impact upon Ontario ratepayers.

Atlantic Power Corporation Interrogatory # 1

Reference:

Exhibit B, Tab 3, Schedule 1

"On September 1, 2015, the IESO published the NUG ("Non-Utility Generator") Framework assessment report ("NUG Report") to the Minister of Energy. This report identified that following the contract expiry of local area generation, reliability standards may not be met without further system reinforcement."

The NUG Report at pgs. 15-16

"While NUGs were initially contracted as system-wide resources without consideration for regional supply needs; they may provide, in some cases, valuable support in maintaining reliability to the local system where they are connected. This potential for local value was included in the assessment conducted by the IESO for each NUG listed in Table 1. The result of this assessment indicates that none of the NUGs, with the potential exception of the Kapuskasing and Calstock NUGs, are required for the purpose of meeting local reliability needs.

The Kapuskasing and Calstock NUGs provide some value in supporting supply reliability in the Hearst/Kapuskasing area. The transmission system in the identified area supplies a large industrial customer with some critical load. While the system can adequately supply the area's loads without these two NUGs when all transmission facilities are available, the Kapuskasing and Calstock NUGs would reduce the risk of load interruptions when transmission facilities are forced out of service."

Interrogatory:

a) Has Hydro One (or the IESO) contacted the owners / operators of the Kapuskasing and Calstock NUGs to discuss the possibility of those NUGs providing short-term capacity relief to address the system need in advance of the launch of a formal capacity auction process for Ontario? Produce all available evidence that this alternative has been fully explored by Hydro One (and the IESO).

b) Produce a detailed assessment of the impact on project need if one or both of the above mentioned NUGs are successful in Ontario's planned capacity auction process.

c) If these NUGs were able to provide short-term capacity relief to address system need, would this give Hydro One (and the IESO) more time to conduct a more comprehensive and fulsome needs analysis prior to seeking leave to construct transmission infrastructure that may not ever be required?

Response:

a.) The IESO did not contact the owners/operators of the Kapuskasing GS and Calstock GS to discuss the possibility of those NUGs providing short-term capacity relief to address the system need in advance of the launch of a formal incremental capacity auction process in Ontario. Using the NUGs to provide short-term capacity relief was not an option that was explored when the assessment was completed; however, to respond to these interrogatories, the IESO explored this option, see Exhibit I, Tab 1, Schedule 3.

b.) The Project is still needed by the year 2020, even if one or both of the NUGs are successful in the IESO's incremental capacity auction. This is because, although the first date of the capacity auction is still being determined; current forecasting from the Long Term Energy Plan indicates a need for incremental capacity to emerge in the mid-2020s. As a result, a reliability need for the project still exists between the time of contract expiry in 2020 and the commitment time of a capacity auction.

c.) A complete analysis has been conducted by the IESO, which established that the Kapuskasing Area Reinforcement Project is the preferred option to meet the needs in the area. The IESO does not believe that any further analysis is required.

Atlantic Power Interrogatory # 2

Reference:

Exhibit B, Tab 3, Schedule 1

"The North-East of Sudbury Regional Planning process commenced on September 24, 2015, and based on the fact that there were existing challenges in operating the bulk transmission system in the area, the IESO and Hydro One agreed that a bulk system study should be run in parallel with the formalized Regional Planning Process. This enabled the bulk system study to be expedited to ensure timely solutions would be in place given the potential lead time for transmission-based solutions. The scope of the bulk system study for the Kapuskasing area investigated the adequacy and operability of the system supplying the Kapuskasing area, as it currently exists, and following the contract expiry of local area generators."

Interrogatory:

a) Produce a copy of the Regional Infrastructure Plan ("RIP") arising from the North-East of Sudbury process. Identify where in this plan the proposed Kapuskasing Reinforcement Project is clearly identified. If the Kapuskasing Reinforcement Project is not clearly identified in the RIP, explain why.

b) Were local generators invited to participate in the Regional Planning process to identify opportunities where their assets might help meet system needs at a lower total cost for ratepayers? If no, why not? If yes, produce all evidence of their involvement.

c) Why did Hydro One (and the IESO) determine that the Kapuskasing Reinforcement Project study should be conducted outside of the Regional Planning process? What external stakeholders were involved in this study? Were local generators directly involved in the study, to identify opportunities where their assets might meet system needs at lower costs for ratepayers? If no, why not?

d) Explain to what extent the Kapuskasing Reinforcement Project study addresses each of the following (which are the core components of Ontario's Regional Planning process[1]):

---

[1] http://www.ieso.ca/en/get-involved/regional-planning/about-regional-planning/overview

- **Coordination:** How did the study address local and regional planning concerns, including without limitation Community Energy Plans and the needs and preferences of local industry and load consumers?
- **Engagement:** How did the study facilitate a strong commitment to public participation, including incorporating the voices of Indigenous communities and municipalities, individuals and business groups?
- **Integration:** How did the study address the best mix of available options, including conservation and demand management, new or increased generation, investment in transmission or distribution facilities, or innovative solutions?

e) Would Hydro One and the IESO be willing to undertake a new study, in consultation with local generators to identify opportunities where their assets might help meet system needs at a lower total cost for ratepayers? If no, why not?

Response:

a) Please refer to Attachment 1 of this interrogatory response for a copy of the Regional Infrastructure Plan ("RIP").

The Kapuskasing Area Reinforcement Project is not explicitly identified as the scope of RIP is to review the supply and reliability issues at a regional or local area level. As documented in the RIP, the NUG Framework Assessment Report completed by the IESO, indicated that local reliability and congestion issues may require further study as this pertains to contracted generation facilities. This is a bulk system issue which will be addressed outside of the scope of regional planning. Consequently, this Project would not have been clearly identified in the RIP.

b) The Kapuskasing Area Reinforcement Project was not identified in the RIP as this project was not planned through the regional planning process. As stated on pages 4-5 of Exhibit B-3-1 Attachment 1, a bulk system study was conducted in parallel with the formalized regional planning process to address bulk transmission system challenges in the Kapuskasing area.

c) The rationale for completing the study as a bulk study rather than through regional planning is provided on pages 4-5 of Exhibit B, Tab 3, Schedule 1, Attachment 1.

The bulk study was conducted between IESO and Hydro One. Local generators were not directly involved in the bulk study. To understand the generation options to meet the reliability need, the IESO leveraged third party cost estimates for new generation facilities and costs for similar IESO-contracted facilities in Ontario. Due to the cost difference between the transmission and generation options, described on page 6 of Exhibit B, Tab 3, Schedule 1, Attachment 1, the IESO concluded that it was not necessary to reach out to the local generators.

d) The study for the Kapuskasing area was conducted as a separate bulk system study and was not part of the North-East of Sudbury regional planning process. As noted above, the IESO's Regional Planning Process is quite distinct from bulk planning studies with the level of engagement on bulk planning studies conducted on a case-by-case basis. In this case, the IESO did not engage externally because of the cost difference between options and the scope of the recommended project.

Please refer to pages 7-8 of Exhibit B, Tab3, Schedule 1, Attachment 1 for the options that were considered. In addition, demand response (DR) was also considered as a potential option to meet the local area need; however, various factors impacted DR consideration including the lack of participation by customers from the area in the DR auction and the DR auction clearing price for the Northeast Zone.

e) Given the lead times associated with the Kapuskasing Area Reinforcement Project, and the differences in cost between the recommended option and the generation alternatives as described on pages 7-8 of Exhibit B, Tab 3, Schedule 1, Attachment 1, the IESO continues to recommend that this project proceed to ensure that a solution is in place in advance of the need date in 2020.

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North/East of Sudbury

Regional Infrastructure Plan (“RIP”)

April 13, 2017

Northern Ontario Wires Inc.
Hearst Power Ltd.
North Bay Hydro Distribution Ltd.
Hydro One Networks Inc. (Distribution)

North/East of Sudbury Region is the area roughly bordered by Moosonee on the North, Hearst on the North-West, Ferris South and Kirkland Lake on the East.

The Local Planning (“LP”) report for the North/East of Sudbury Region was completed on August 8, 2016 (see attached), and identified the following needs in the region:

- Timmins TS/Kirkland Lake TS – Voltage Regulation Issues:

In the LP report, the study team acknowledged that the Timmins TS 115kV bus may experience voltages below ORTAC requirements following a contingency to both Porcupine TS K1K4 and K1K2 breakers. Operating measures are established to control the voltage decline post contingency, and the study team concluded no action is currently required. Hydro One will continue to monitor Timmins area load growth to ensure operating measures outlined in the LP report continue to be effective for voltage regulations.

The LP also report concluded that corrective actions to control voltage violations on the system may be required for any new loads in the Kirkland Lake or Dymond area.

Consistent with a process established by an industry working group[1] created by the OEB the Regional Infrastructure Plan (“RIP”) is the last phase of the planning process. In view that no further regional coordination was required, the attached NA and LP reports will be deemed to form the RIP for the North/East of Sudbury Region.

The next planning cycle for the region will take place within five years of the start of this cycle (2021) or earlier, should there be a new need identified in the region.

Sincerely,

Ajay Garg | Manager, Regional Planning Co-ordination
Hydro One Networks Inc.

[1] Planning Process Working Group (PPWG) Report to the Ontario Energy Board available at the OEB website www.ontarioenergyboard.ca

Hydro One Networks Inc.
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LOCAL PLANNING REPORT

Timmins / Kirkland Lake Voltage Regulation
Region: North & East of Sudbury

Revision: FINAL
Date: August 8, 2016

Prepared by: Hydro One Networks Inc (Transmission & Distribution)

Study Team

Organization
Hydro One Networks Inc. (Lead Transmitter)
Hydro One Networks Inc. (Distribution)

DISCLAIMER

This Local Planning Report was prepared for the purpose of developing wires-only options and recommending a preferred solution(s) to address the local needs identified in the Needs Assessment (NA) report for the North & East of Sudbury Region that do not require further coordinated regional planning. The preferred solution(s) that have been identified through this Local Planning Report may be reevaluated based on the findings of further analysis. The load forecast and results reported in this Local Planning Report are based on the information and assumptions provided by study team participants.

Study team participants, their respective affiliated organizations, and Hydro One Networks Inc. (collectively, "the Authors") make no representations or warranties (express, implied, statutory or otherwise) as to the Local Planning Report or its contents, including, without limitation, the accuracy or completeness of the information therein and shall not, under any circumstances whatsoever, be liable to each other, or to any third party for whom the Local Planning Report was prepared ("the Intended Third Parties"), or to any other third party reading or receiving the Local Planning Report ("the Other Third Parties"), for any direct, indirect or consequential loss or damages or for any punitive, incidental or special damages or any loss of profit, loss of contract, loss of opportunity or loss of goodwill resulting from or in any way related to the reliance on, acceptance or use of the Local Planning Report or its contents by any person or entity, including, but not limited to, the aforementioned persons and entities.

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LOCAL PLANNING EXECUTIVE SUMMARY

REGION	North & East of Sudbury (the "Region")		
LEAD	Hydro One Networks Inc. ("Hydro One")		
START DATE	May 9, 2016	**END DATE**	November 30, 2016

1. INTRODUCTION

The purpose of this Local Planning (LP) report is to develop wires-only option and recommend a preferred solution that will address the local needs identified in the Needs Assessment (NA) report for the North & East of Sudbury Region dated April 15, 2016. The development of the LP report is in accordance with the regional planning process as set out in the Ontario Energy Board's (OEB) Transmission System Code (TSC) and Distribution System Code (DSC) requirements and the "Planning Process Working Group (PPWG) Report to the Board".

Based on Section 7 of the NA report, the study team recommended that no further coordinated regional planning is required to address the needs in the North & East of Sudbury region. These needs are local in nature and will be addressed by wires options through local planning led by Hydro One with participation of the impacted LDC.

2. LOCAL NEEDS ADDRESSED IN THIS REPORT

The Timmins and Kirkland Lake area voltage regulation are local needs addressed in this report.

3. OPTIONS CONSIDERED

Hydro One (Transmitter) and Hydro One Distribution (LDC) have considered addressing the Timmins TS voltage regulation need with the following options;

Alternative 0 – Status Quo.

Alternative 1 - Implement a Load Rejection Scheme on T61S and P7G

Hydro One (Transmitter) and Hydro One Distribution (LDC) have agreed that Alternative 0 – Status Quo is the only option to be considered for Kirkland Lake TS voltage regulation need.

See Section 3 for further detail.

4. PREFERRED SOLUTION

The preferred solution at this time for both the Timmins TS and Kirkland Lake TS voltage regulation needs are Alternative 0 – Status Quo. See Section 4 for details.

5. NEXT STEPS

The next steps are summarized in section 5

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1 Introduction

The Needs Assessment (NA) for the North & East of Sudbury ("Region") was triggered in response to the Ontario Energy Board's (OEB) Regional Infrastructure Planning process approved in August 2013. Prior to the new regional planning process coming into effect, planning activities were already underway in the Region to address some specific station capacity needs. The NA report can be found on Hydro One's Regional Planning website. The study team identified needs that are emerging in the North & East of Sudbury Region over the next ten years (2016-2026) and recommended whether they should be further assessed through the transmitter-led Local Planning (LP) process or the IESO-led Scoping Assessment (SA) process.

1.1 North & East of Sudbury Region Description and Connection Configuration

The North & East of Sudbury Region are bounded by regions of North Bay, Timmins, Hearst, Moosonee, Kirkland Lake and Dymond. A map of the region is shown below in Figure 1.

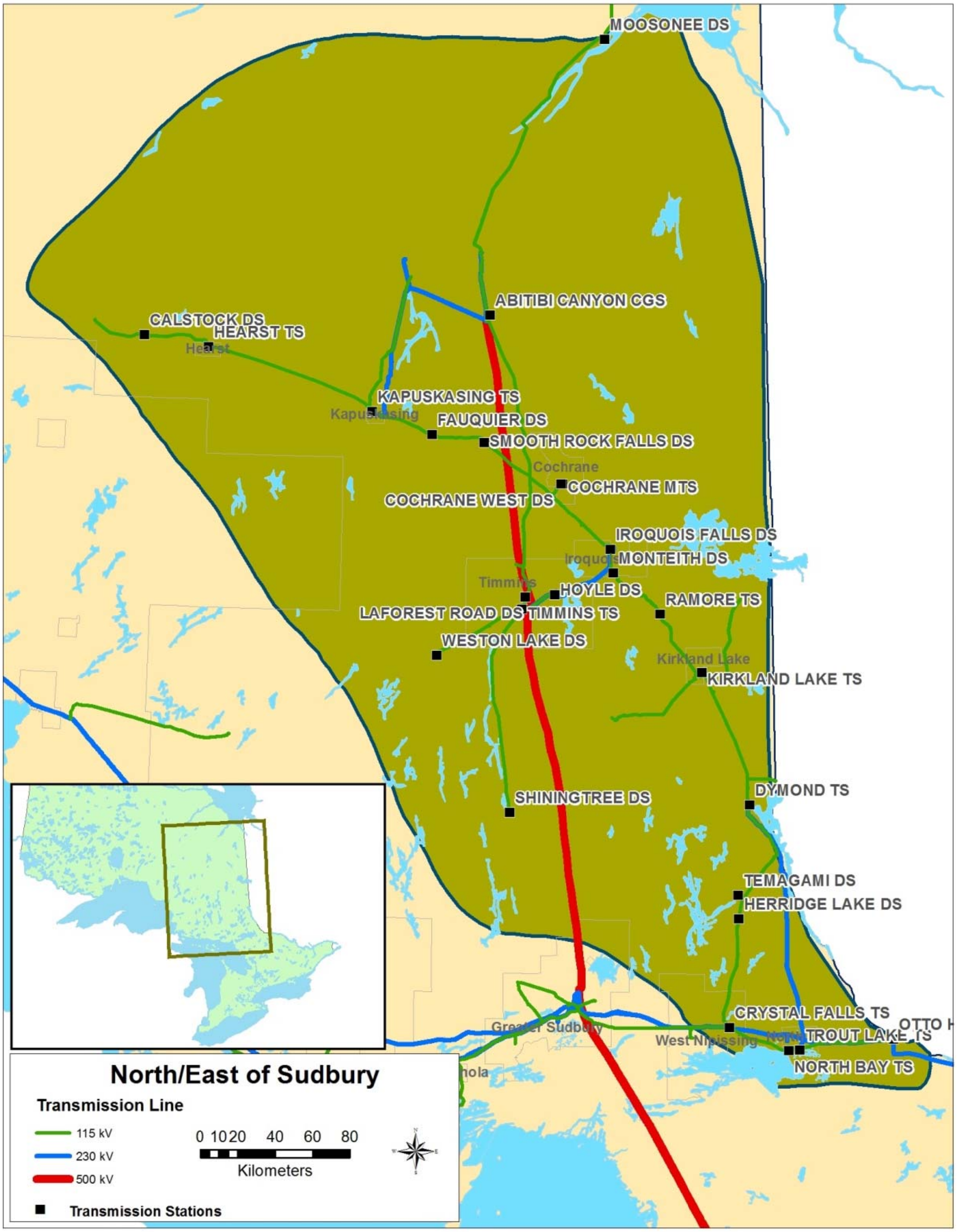

Figure 1: North & East of Sudbury Region Map

Electrical supply for this region is provided through a network of 230kV and 115kV transmission circuits. This area is further reinforced through the 500kV circuits P502X and D501P connecting Pinard TS to Hanmer TS. This region has the following four local distribution companies (LDC):

Hydro One Networks (distribution)
Northern Ontario Wires Inc
Hearst Power Ltd
North Bay Hydro Distribution Ltd.

Table 1: Transmission Lines and Stations in North & East of Sudbury Region

115kV circuits	230kV circuits	500kV circuits	Hydro One Transformer Stations
L5H, L1S D2L, D3K A8K, A9K K2, K4 A4H, A5H D2H, D3H P7G, H9K P13T, P15T T61S, F1E L8L, T7M T8M, H6T H7T, D6T	H23S, H24S W71D, P91G D23G, K38S R21D, L20D L21S, H22D	P502X, D501P	Ansonville TS * Crystal Falls TS Dymond TS * Hearst TS Hunta SS Kapuskasing TS Kirkland Lake TS Little Long SS Moosonee SS North Bay TS Otter Rapids SS Otto Holden TS * Pinard TS * Porcupine TS * Spruce Falls TS* Timmins TS Trout Lake TS Widdifield SS

*Stations with Autotransformers installed

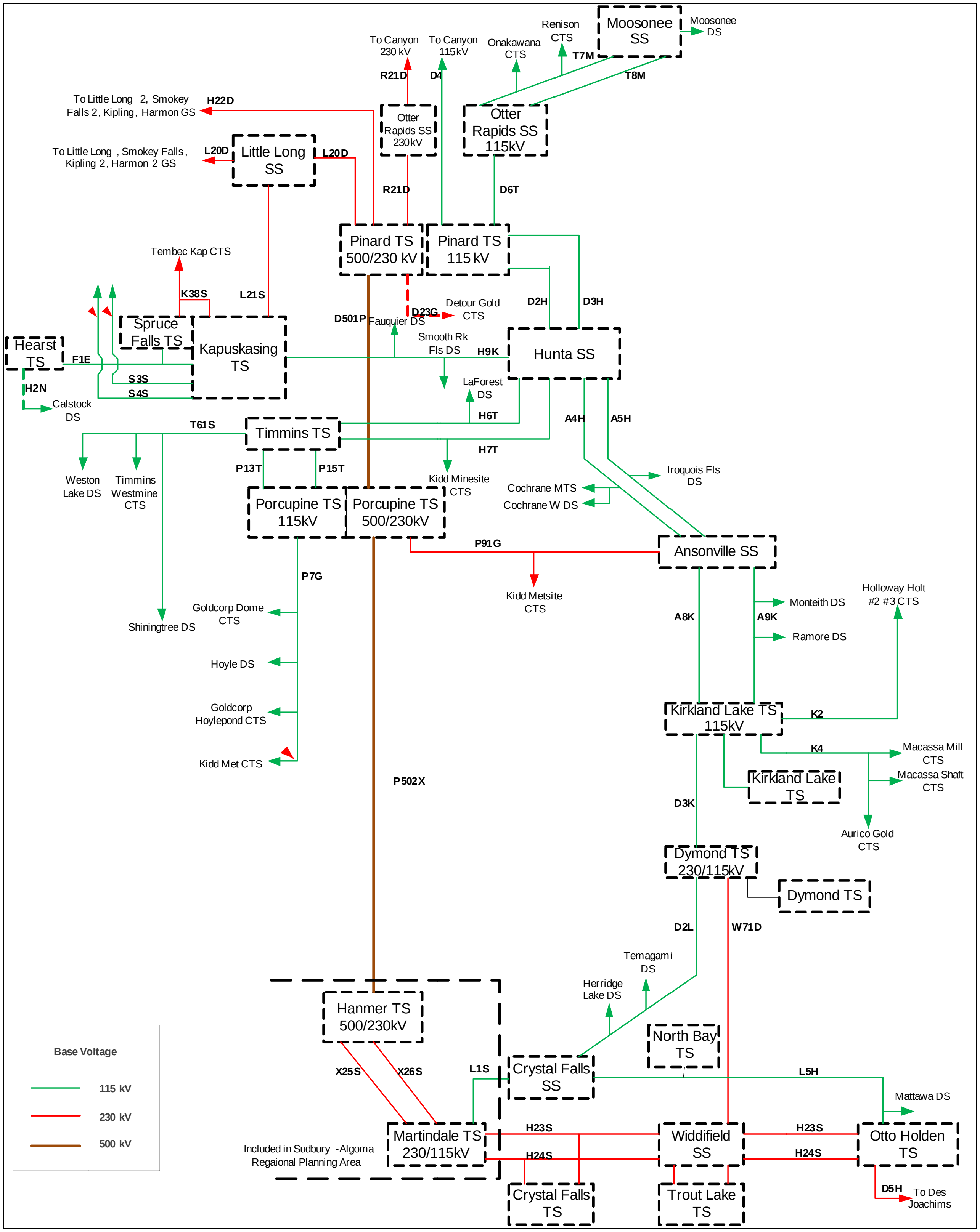

Figure 2: North and East of Sudbury Regional Planning Electrical Diagram

2 Area Needs

2.1 North & East of Sudbury Region Needs

As an outcome of the NA process, the study team identified voltage regulation issues at Timmins TS and Kirkland Lake TS which are addressed in this report. Local planning was recommended, and Hydro One as the transmitter, with the impacted LDC further undertook planning assessments to address the following needs;

- Timmins TS voltage regulation - The loss of Porcupine TS 115kV circuit breakers (K1K4 and K1K2) may result in voltage declines at Timmins TS 115kV bus in excess of 10%. This is considered an n-1-1 contingency and load rejection following the loss of the second element was proposed by IESO to improve post contingency voltage performance. See Figure 3 – Timmins area connection diagram for reference.

- Kirkland Lake TS voltage regulation - The loss of Ansonville T2 and D3K may result in voltage declines at Kirkland Lake TS 115kV bus in excess of 10%. This is considered an n-1-1 contingency and all new loads in the area will be required to participate in a local load rejection scheme to help improve post contingency voltage performance.

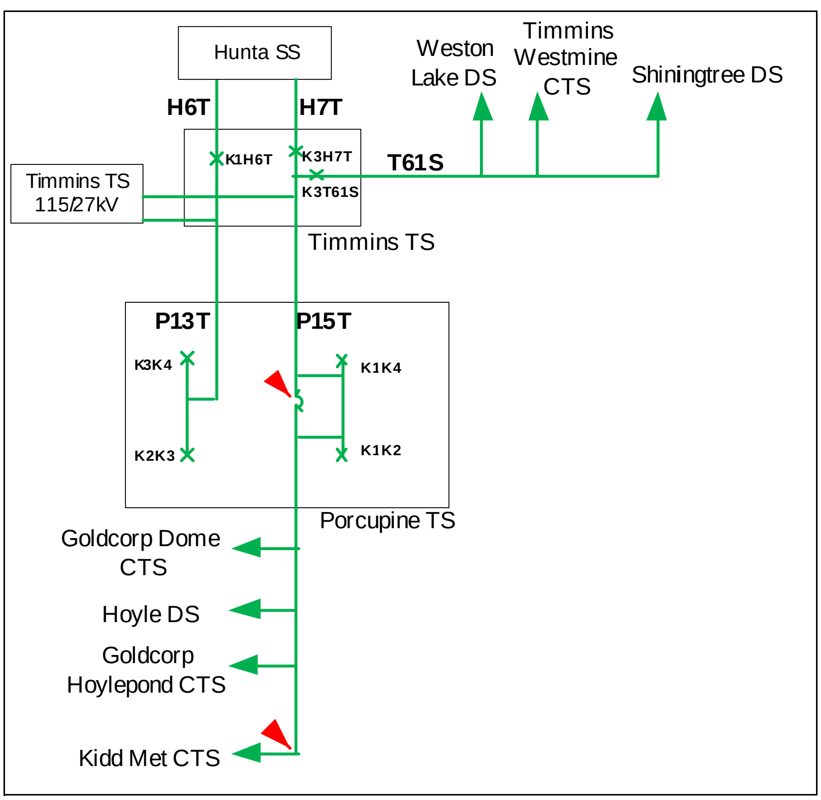

Figure 3: Timmins area connection diagram

3 Alternatives Considered

3.1 Timmins TS Voltage regulation

Alternative 1 – Status Quo.

No further action is required at this time. Hydro One and LDC will monitor the loads and voltages in the area in the upcoming years. Further review of this issue will be undertaken in the next planning cycle or earlier if there is evidence that load cannot be served or system cannot be operated in a safe, secure and reliable manner. Voltage issues can be addressed with operating procedures which are presently in place without any use of load rejection.

Alternative 2 – Implement Load Rejection on T61S, P7G, P15T to control Timmins TS voltages

This option will require expansion of the Northeast LR/GR scheme to include tripping of the Hydro One 115kV T61S, P7G, and P15T circuits upon contingency of both Porcupine TS K1K4 and K1K2 circuit breakers. This will allow for automatic load rejection of approximately 40MW of load.

Table 2: Budgetary Cost for Alternatives

Options Considered	Cost
Alternative 1 – Hydro One to assess voltage performance with no immediate investment.	--
Alternative 2 – Expand Northeast Special Protection Scheme (SPS) to include P15T, P7G, T61S circuits	$2M

3.2 Kirkland Lake TS Voltage regulation

Alternative 1 – Status Quo. See details in section 4 below.

4 Preferred Solution and Reasoning

4.1 Timmins TS Voltage regulation

Hydro One Networks and Hydro One Distribution have reviewed all alternatives and the preferred solution at this time is, Alternative 1 – Status Quo.

The study team acknowledges that Timmins TS 115kV bus may experience voltages below ORTAC requirements following a contingency to both Porcupine TS K1K4 and K1K2 breakers. The possibility of this scenario is remote and there are established operating measures in place should the first Porcupine TS breaker (either K1K4 or K1K2) be placed out of service. The following control measures are taken which help alleviate the voltage decline post contingency.

- Open Timmins TS LV breaker to offload Timmins TS from P15T
- Transfer P7G load to P91G by closing breaker B5L2 at Kidd Creek Metsite and open Porcupine TS switch 30-P7G
- Place one Abitibi Canyon 115kV unit on condenser mode.

Hydro One Networks and Hydro One Distribution have agreed that these operating measures are a preferred alternative to load rejection. In addition, implementing the load rejection scheme will expose the customers in the area to unnecessary interruption due to misoperation of the load rejection scheme.

Hydro One will continue to monitor Timmins area load growth from both LDCs and industrial customers to ensure load growth (if any) does not make voltage situation worse whereby the above operating measures are no longer effective. The next planning cycle will take place within five years and an investment can be triggered at any time should there be a situation where load cannot be served or system cannot be operated safely and reliably.

4.2 Kirkland Lake TS Voltage Regulation

Hydro One Networks and Hydro One Distribution agree that new loads in the Kirkland Lake or Dymond area may be subject to participate in an under voltage load rejection scheme as part to help control voltages in the area post contingency. Presently there is no load growth in the area over the study period. Investments are not required at this time for existing LDC loads and Hydro One will monitor load growth in the area and take corrective action as required or when instructed to do so by the IESO as proponent connection requirements. These will be identified during the load connection process after the connection applications and will be implemented by Hydro One.

5 Next Steps

A summary of the next steps, actions/solutions and timelines required to address the local needs are as follows:

Table 3: Solutions and Timeframe

Need	Action / Recommended Solution	Lead Responsibility	Timeframe
Timmins TS Voltage Regulation	• No Immediate action required • Hydro One and LDC to monitor area load growth	Hydro One Networks	Five years
Kirkland Lake TS Voltage Regulation	• No Immediate action required • Connection requirements for new transmission or distribution connections to be implemented as identified during system studies.	Hydro One Networks	N/A

6 References

[1] Planning Process Working Group (PPWG) Report to the Board: The Process for Regional Infrastructure Planning in Ontario – May 17, 2013

[2] IESO Ontario Resource and Transmission Assessment Criteria (ORTAC)

[3] North & East of Sudbury Needs Assessment Report

Appendix A: Load Forecast for North & East of Sudbury Stations

Transformer Station Name	Customer Data (MW)	Historical Term Forecast (MW)			Near Term Forecast (MW)					Medium Term Forecast (MW)					
		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Kapuskasing TS	Gross Peak Load				13.5	13.6	13.6	13.7	13.8	13.8	13.9	13.9	14.0	14.0	14.0
	Net Load Forecast	26.1	16.1	13.5	13.4	13.3	13.2	13.2	13.1	13.1	13.1	13.0	13.0	13.0	13.0
Trout Lake TS	Gross Peak Load				121.9	122.2	122.7	123.3	123.9	125.3	126.7	127.1	128.4	129.8	131.2
	Net Load Forecast	147.5	124.1	119.4	120.6	120.0	119.1	118.5	118.1	118.7	119.2	119.1	119.7	120.5	121.1
Dymond TS	Gross Peak Load				32.7	32.9	33.1	33.6	34.0	34.2	34.4	34.6	34.8	35.0	35.2
	Net Load Forecast	37.7	34.6	32.4	32.4	32.3	32.2	32.2	32.4	32.4	32.4	32.4	32.4	32.5	32.5
Kirkland Lake TS	Gross Peak Load				32.2	32.3	32.6	32.9	33.3	33.5	33.7	33.8	34.0	34.1	34.3
	Net Load Forecast	43.8	35.7	31.9	31.9	31.7	31.6	31.7	31.7	31.7	31.7	31.7	31.7	31.7	31.6
Timmins TS	Gross Peak Load				53.4	53.7	54.2	54.9	55.6	56.0	56.4	56.7	57.0	57.4	57.7
	Net Load Forecast	51.0	51.1	52.9	52.8	52.7	52.6	52.7	53.0	53.0	53.0	53.1	53.2	53.2	53.3
Hearst TS	Gross Peak Load				27.5	27.6	28.8	29.1	29.3	29.5	29.7	29.9	30.0	30.2	30.4
	Net Load Forecast	27.8	27.3	27.2	27.2	27.1	28.0	27.9	28.0	28.0	28.0	28.0	28.0	28.0	28.0
Herridge Lake DS	Gross Peak Load				3.0	3.1	3.1	3.2	3.2	3.3	3.3	3.4	3.4	3.5	3.5
	Net Load Forecast	3.5	3.8	3.0	3.0	3.0	3.0	3.1	3.1	3.1	3.1	3.2	3.2	3.2	3.2
Temagami DS	Gross Peak Load				2.4	2.4	2.4	2.5	2.5	2.5	2.5	2.5	2.6	2.6	2.6
	Net Load Forecast	2.5	2.6	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4
LaForest Rd TS	Gross Peak Load				10.4	10.4	10.5	10.7	10.8	10.9	10.9	11.0	11.1	11.1	11.2
	Net Load Forecast	12.8	9.7	10.3	10.3	10.2	10.2	10.2	10.3	10.3	10.3	10.3	10.3	10.3	10.3
Hoyle TS	Gross Peak Load				8.9	8.9	9.0	9.2	9.3	9.4	9.5	9.5	9.6	9.7	9.7
	Net Load Forecast	9.3	10.4	8.8	8.8	8.8	8.8	8.8	8.9	8.9	8.9	8.9	8.9	9.0	9.0
Monteith DS	Gross Peak Load				2.8	2.8	2.8	2.8	2.9	2.9	2.9	3.0	3.0	3.0	3.0
	Net Load Forecast	3.1	2.9	2.7	2.7	2.7	2.7	2.7	2.8	2.8	2.8	2.8	2.8	2.8	2.8
Ramore TS	Gross Peak Load				9.1	9.2	9.3	9.5	9.7	9.8	9.9	10.1	10.2	10.3	10.4
	Net Load Forecast	8.2	9.1	8.9	9.0	9.0	9.1	9.1	9.2	9.3	9.4	9.4	9.5	9.6	9.6
Cochrane West DS	Gross Peak Load				3.8	3.8	3.8	3.9	3.9	3.9	4.0	4.0	4.0	4.0	4.1
	Net Load Forecast	4.1	4.1	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7
Smooth Rock Falls DS	Gross Peak Load				2.2	2.2	2.2	2.3	2.3	2.3	2.3	2.3	2.4	2.4	2.4
	Net Load Forecast	2.4	2.4	2.1	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2
Fauquier DS	Gross Peak Load				2.1	2.1	2.2	2.2	2.2	2.3	2.3	2.3	2.3	2.3	2.4
	Net Load Forecast	2.3	2.3	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.2	2.2	2.2	2.2
Moosonee DS	Gross Peak Load				14.2	14.3	14.4	14.6	14.8	14.9	15.0	15.0	15.1	15.2	15.3
	Net Load Forecast	18.0	13.5	14.1	14.1	14.0	14.0	14.0	14.1	14.1	14.1	14.1	14.1	14.1	14.1
Calstock DS	Gross Peak Load				5.0	5.0	5.1	5.2	5.2	5.3	5.3	5.4	5.4	5.5	5.5
	Net Load Forecast	5.1	4.9	4.9	4.9	4.9	4.9	5.0	5.0	5.0	5.0	5.1	5.1	5.1	5.1
Mattawa DS	Gross Peak Load				5.5	5.5	5.6	5.7	5.7	5.8	5.8	5.8	5.9	5.9	5.9
	Net Load Forecast				5.4	5.4	5.4	5.4	5.5	5.5	5.5	5.5	5.5	5.5	5.5
Iroquois Falls DS	Gross Peak Load				10.8	10.9	10.9	11.0	11.1	11.1	11.2	11.2	11.2	11.3	11.3
	Net Load Forecast	5.1	4.9	4.9	10.7	10.7	10.6	10.6	10.5	10.5	10.5	10.5	10.5	10.5	10.5
Crystal Falls TS	Gross Peak Load				9.9	10.0	10.0	10.2	10.3	10.4	10.4	10.5	10.5	10.6	10.6
	Net Load Forecast	18.7	11.1	9.8	9.8	9.8	9.7	9.8	9.8	9.8	9.8	9.8	9.8	9.8	9.8
Cochrane MTS	Gross Peak Load				11.3	11.4	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6
	Net Load Forecast	10.3	10.9	11.1	11.1	11.2	11.2	11.1	11.0	11.0	10.9	10.8	10.8	10.7	10.7
North Bay	Gross Peak Load				39.0	39.0	39.0	39.0	39.0	39.4	39.8	40.2	40.6	41.0	41.4
	Net Load Forecast	29.0	39.0	25.0	38.6	38.3	37.9	37.5	37.2	37.3	37.4	37.7	37.8	38.0	38.2

Load Forecast for North & East of Sudbury Stations (Continued)

Transformer Station Name	Customer Data (MW)	Historical Term Forecast (MW)			Near Term Forecast (MW)					Medium Term Forecast (MW)					
		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Weston Lake DS	Gross Peak Load				4.1	4.1	4.2	4.2	4.3	4.3	4.3	4.4	4.4	4.4	4.4
	Net Load Forecast	4.1	4.3	4.1	4.0	4.0	4.0	4.1	4.1	4.1	4.1	4.2	4.2	4.2	4.2
Shiningtree DS	Gross Peak Load				4.1	4.1	4.2	4.2	4.3	4.3	4.3	4.4	4.4	4.4	4.4
	Net Load Forecast	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.1	4.1	4.1	4.2	4.2	4.2	4.2

Appendix B: Acronyms

BES	Bulk Electric System
BPS	Bulk Power System
CDM	Conservation and Demand Management
CIA	Customer Impact Assessment
CGS	Customer Generating Station
CTS	Customer Transformer Station
DESN	Dual Element Spot Network
DG	Distributed Generation
DSC	Distribution System Code
GS	Generating Station
GTA	Greater Toronto Area
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Planning
kV	Kilovolt
LDC	Local Distribution Company
LP	Local Planning
LTE	Long Term Emergency
LTR	Limited Time Rating
LV	Low-voltage
MW	Megawatt
MVA	Mega Volt-Ampere
NA	Needs Assessment
NERC	North American Electric Reliability Corporation
NGS	Nuclear Generating Station
NPCC	Northeast Power Coordinating Council Inc.
OEB	Ontario Energy Board
OPA	Ontario Power Authority
ORTAC	Ontario Resource and Transmission Assessment Criteria
PF	Power Factor
PPWG	Planning Process Working Group
RIP	Regional Infrastructure Planning
SIA	System Impact Assessment
SS	Switching Station
TS	Transformer Station
TSC	Transmission System Code
ULTC	Under Load Tap Changer

Hydro One Networks Inc.
483 Bay Street
Toronto, Ontario
M5G 2P5

NEEDS ASSESSMENT REPORT

Region: North and East of Sudbury

Date: April 15, 2016

Prepared by: North and East of Sudbury Region Working Group

North & East of Sudbury Working Group	
Organization	**Name**
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Independent Electricity System Operator	Chris Reali Philip Woo
Hydro One Networks Inc. (Distribution)	Richard Shannon Daniel Boutros
Northern Ontario Wires Inc	Dan Boucher
Hearst Power Ltd	D Sampson J Richard
North Bay Hydro Distribution Ltd	Matt Payne

Disclaimer

This Needs Assessment Report was prepared for the purpose of identifying potential needs in the North & East of Sudbury region and to assess whether those needs require further coordinated regional planning. The potential needs that have been identified through this Needs Assessment Report may be studied further through subsequent regional planning processes and may be reevaluated based on the findings of further analysis. The load forecast and results reported in this Needs Assessment Report are based on the information and assumptions provided by Working Group participants.

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NEEDS ASSESSMENT EXECUTIVE SUMMARY

REGION	North & East of Sudbury (the "Region")		
LEAD	Hydro One Networks Inc. ("Hydro One")		
START DATE	October 15, 2015	**END DATE**	April 15, 2016

1. INTRODUCTION

The purpose of this Needs Assessment (NA) report is to undertake an assessment of the North & East of Sudbury Region and determine if there are regional needs that require coordinated regional planning. Where regional coordination is not required, and a "localized" wires solution is necessary, such needs will be addressed between relevant Local Distribution Companies (LDCs) and Hydro One and other parties as required.

For needs that require further regional planning and coordination, IESO will initiate the Scoping Assessment (SA) process to determine whether an IESO-led Integrated Regional Resource Planning (IRRP) process, or the transmitter-led Regional Infrastructure Plan (RIP) process (wires solution), or whether both are required.

2. REGIONAL ISSUE / TRIGGER

The NA for the North & East of Sudbury Region was triggered in response to the Ontario Energy Board's (OEB) Regional Infrastructure Planning process approved in August 2013. To prioritize and manage the regional planning process, Ontario's 21 regions were assigned to one of three groups. The NA for Group 1 and 2 regions is complete and has been initiated for Group 3 Regions. The North & East of Sudbury Region belongs to Group 3, triggered on October 15, 2015 and completed on April 17, 2016

3. SCOPE OF NEEDS ASSESSMENT

The scope of the NA study was limited to 10 years as per the recommendations of the Planning Process Working Group (PPWG) Report to the Board. As such, relevant data and information was collected up to the year 2026. Needs emerging over the next 10 years and requiring coordinated regional planning may be further assessed as part of the IESO-led SA, which will determine the appropriate regional planning approach: IRRP, RIP, and/or local planning. This NA included a study of transmission system connection facilities capability, which covers station loading, thermal and voltage analysis as well as a review of system reliability, operational issues such as load restoration, and assets approaching end-of-useful-life.

4. INPUTS/DATA

Working Group participants included representatives from LDCs, the Independent Electricity System Operator (IESO), and Hydro One. The information included: historical load, load forecast, conservation and demand management (CDM) and distributed generation (DG) information, load restoration data, and performance information including major equipment approaching end-of-useful life.

5. NEEDS ASSESSMENT METHODOLOGY

The assessment's primary objective is to identify the electrical infrastructure needs and system performance issues in the Region over the study period (2016 to 2026). The assessment reviewed available information, load forecasts and included single contingency analysis to confirm needs, if and when required.

6. RESULTS - TRANSMISSION NEEDS

A. 500/230kV Autotransfomers

The 500/230kV Autotransformers supplying the regional are adequate over the study period for the loss of a single 500/230kV unit.

B. 500/115kV Autotransfomers

The 500/115kV Autotransformers supplying the regional are adequate over the study period for the loss of a single 500/115kV unit

C. 230/115 kV Autotransformers

The 230/115kV Autotransformers supplying the regional are adequate over the study period for the loss of a single 230/115kV unit

D. Transmission Lines & Ratings

The 500kV, 230kV transmission lines are adequate over the study period.

Sections of the 115kV H9K circuit may experience thermal overloads during high generation scenarios. This is a bulk system issue and will be addressed jointly with the IESO outside of regional planning.

E. 230 kV and 115 kV Connection Facilities

The 230kV and 115kV connection facilities in this region are adequate over the study period.

F. Outage Condition resulting in P15T,P7G and T61S radially connected to Timmins TS

The loss of K1K4 and K1K2 circuit breakers at Porcupine TS can result in excessive voltage declines at Timmins TS 115kV bus

G. Ansonville T2 or D3K Outages

With Ansonville T2 or D3K out of service, the loss of the other can result in excessive voltage decline at the Kirkland Lake TS 115kV bus.

<u>System Reliability, Operation and Restoration Review</u>

Circuit reliability in the region is acceptable, and Hydro One will continue to monitor performance of supply stations and circuits to ensure customer delivery performance criteria are met.

Restoration requirements for the loss of one element can be met by Hydro One.
Restoration requirements for the loss of up to two elements can be met by Hydro One.

Aging Infrastructure / Replacement Plan

Within the regional planning time horizon, the following work is part of Hydro One approved sustainment business plan

Dymond TS (T3/T4) transformers (2016)
Kirkland Lake TS (T12/T13) transformers (2017)
Timmins TS (T63/T64) with single 83MVA (2016)
Otto Holden TS (T3/T4) autotransformers, and 115kV circuit breakers (2019)

7. RESULTS – NEEDS ASSESSMENT REPORT

Based on the findings of the Needs Assessment, the Working Group recommends that no further regional coordination is required and following needs identified be further assessed as part of Local Planning:

Timmins TS / Kirkland Lake TS – Voltage Regulation Issues

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LIST OF FIGURES

1 INTRODUCTION

This Needs Assessment (NA) report provides a summary of needs that are emerging in the North & East of Sudbury Region ("Region") over the next ten years. The development of the NA report is in accordance with the regional planning process as set out in the Ontario Energy Board's (OEB) Transmission System Code (TSC) and Distribution System Code (DSC) requirements and the "Planning Process Working Group (PPWG) Report to the Board".

The purpose of this NA is to undertake an assessment of the North & East of Sudbury Region to identify any near term and/or emerging needs in the area and determine if these needs require a "localized" wires only solution(s) in the near-term and/or a coordinated regional planning assessment. Where a local wires only solution is necessary to address the needs, Hydro One, as transmitter, with Local Distribution Companies (LDC) or other connecting customer(s), will further undertake planning assessments to develop options and recommend a solution(s). For needs that require further regional planning and coordination, the Independent Electricity System Operator (IESO) will initiate the Scoping Assessment (SA) process to determine whether an IESO-led Integrated Regional Resource Planning (IRRP) process, or the transmitter-led Regional Infrastructure Plan (RIP) process (wires solution), or both are required. If localized wires only solutions do not require further coordinated regional planning, the SA may also recommend that local planning between the transmitter and affected LDCs be undertaken to address certain needs.

This report was prepared by Hydro One Inc ("Hydro One") on behalf of the North & East of Sudbury Region NA Working Group (Table 1). The report captures the results of the assessment based on information provided by LDCs, and the Independent Electricity System Operator (IESO).

Table 1: Working Group Participants for North & East of Sudbury Region

No.	Company
1.	Hydro One Networks Inc. (Lead Transmitter)
2.	Independent Electricity System Operator
3.	Northern Ontario Wires Inc
4.	Hydro One Networks Inc. (Distribution)
5.	Hearst Power Ltd
6.	North Bay Hydro Inc.

2 Regional Issue / Trigger

The NA for the North & East of Sudbury Region was triggered in response to the OEB's Regional Infrastructure Planning process approved in August 2013. To prioritize and manage the regional planning process, Ontario's 21 regions were assigned to one of three groups. The North & East of Sudbury Region belongs to Group 3.

3 Scope of Needs Assessment

This NA covers the North & East of Sudbury Region over an assessment period of 2016 to 2026. The scope of the NA includes a review of transmission system connection facility capability which covers transformer station capacity, thermal capacity, and voltage performance. System reliability, operational issues such as load restoration, and asset replacement plans were also briefly reviewed as part of this NA.

North & East of Sudbury Region Description and Connection Configuration
The North & East of Sudbury Region are bounded by regions of North Bay, Timmins, Hearst, Moosonee, Kirkland Lake and Dymond. A map of the region is shown below in Figure 1.

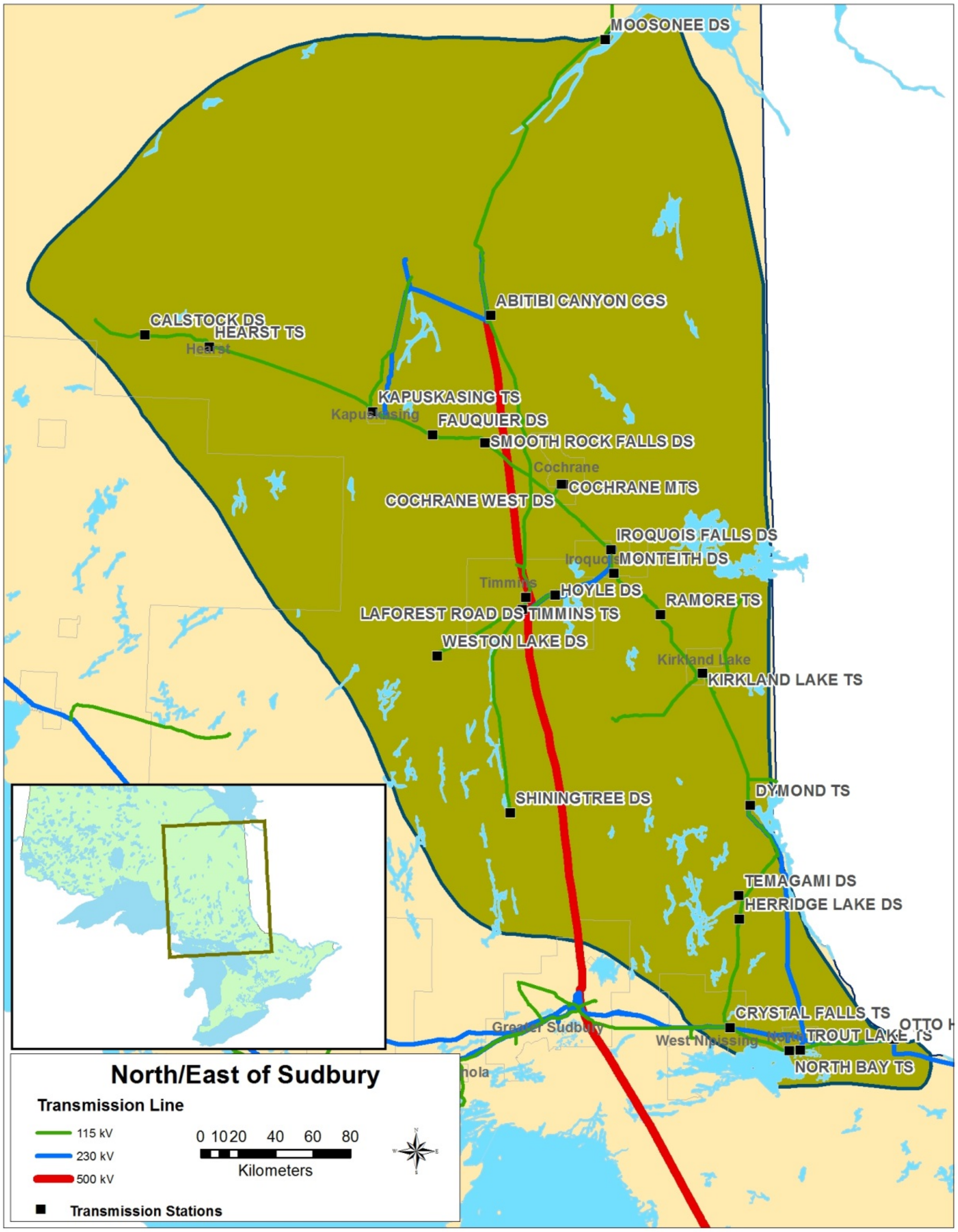

Figure 1: North & East of Sudbury Region Map

Electrical supply for this region is provided through a network of 230kV and 115kV transmission circuits. This area is further reinforced through the 500kV circuits P502X and D501P connecting Pinard TS to Hanmer TS.

This region has the following four local distribution companies (LDC):

- Hydro One Networks (distribution)
- Northern Ontario Wires Inc
- Hearst Power Ltd
- North Bay Hydro Distribution Ltd.

115kV circuits	230kV circuits	500kV circuits	Hydro One Transformer Stations
L5H, L1S D2L, D3K A8K, A9K K2, K4 A4H, A5H D2H, D3H P7G, H9K P13T, P15T T61S, F1E L8L, T7M T8M, H6T H7T, D6T	H23S, H24S W71D, P91G D23G, K38S R21D, L20D L21S, H22D	P502X, D501P	Ansonville TS * Crystal Falls TS Dymond TS * Hearst TS Hunta SS Kapuskasing TS Kirkland Lake TS Little Long SS Moosonee SS North Bay TS Otter Rapids SS Otto Holden TS * Pinard TS * Porcupine TS * Spruce Falls TS * Timmins TS Trout Lake TS Widdifield SS

***Stations with Autotransformers installed**

Table 2: Transmission Lines and Stations in North & East of Sudbury Region

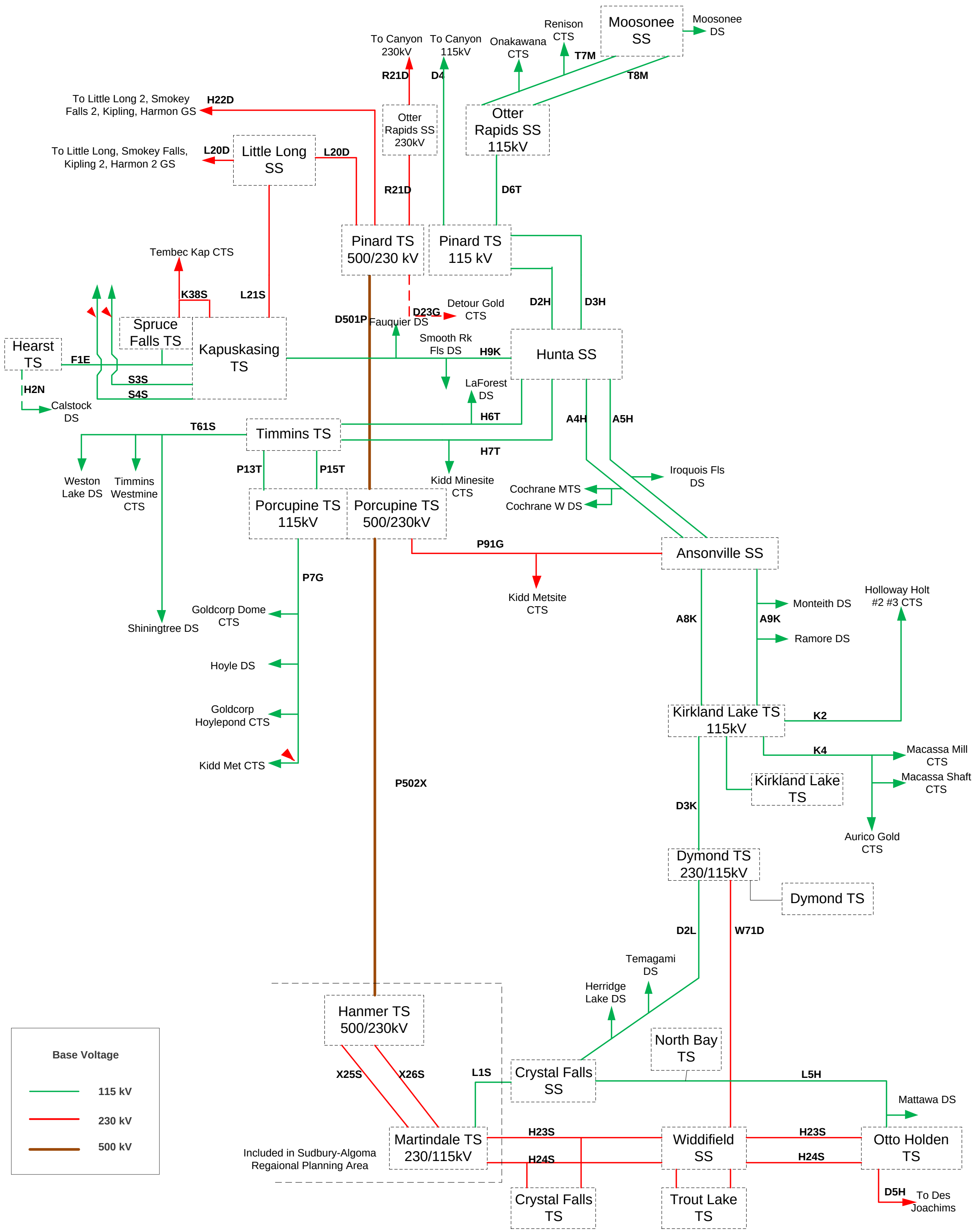

Figure 2 – North and East of Sudbury Regional Planning Electrical Diagram

4 Inputs and Data

In order to conduct this Needs Assessment, Working Group participants provided the following information and data to Hydro One:

- IESO provided:
  1. Historical Ontario and regional coincident load station peaks, as well as individual station peaks.
  2. List of existing reliability and operational issues
  3. Conservation and Demand Management (CDM) and Distributed Generation (DG) data
- LDCs provided historical (2013-2015) net load and gross load forecast (2016-2026) Note: 2026 gross load values were extrapolated from 2025 if required.
- Hydro One (Transmission) provided transformer, station, and circuit ratings
- Any relevant planning information, including planned transmission and distribution investments provided by the transmitter and LDCs, etc.

Load Forecast
As per the data provided by the Working Group, the gross load in region is expected to grow at an average rate of approximately 0.7% annually from 2016-2026.

The net load forecast takes the gross load forecast and applies the planned CDM targets and DG contributions. With these factors in place, the total regional load is expected to increase at an average rate of approximately 0.04% annually from 2016-2026.
Note: Extreme weather scenario factor at 1.057 assessed over the study term.

5 Needs Assessment Methodology

The following methodology and assumptions are made in this Needs Assessment:

1. The Region is winter peaking so this assessment is based on winter peak loads.
2. Forecast loads are provided by the Region's LDCs
3. Load data was provided by industrial customers in the region. Where data was not provided, the load was assumed to be consistent with historical loads.
4. Accounting for (2), (3) above, the gross load forecast and net load forecast were developed. The gross load forecast is used to develop a worst case scenario to identify needs. Where there are issues, the net load forecast which accounts for CDM and DG are analyzed to determine if needs can be deferred. A gross and net non-coincident peak load forecast was used to perform the analysis for this report. A gross and net region-coincident peak load forecast was used to perform the analysis.

5. Review impact of any on-going and/or planned development projects in the Region during the study period.
6. Review and assess impact of any critical/major elements planned/identified to be replaced at the end of their useful life such as autotransformers, cables, and stations.
7. Station capacity adequacy is assessed by comparing the non-coincident peak load with the station's normal planning supply capacity assuming a 90% lagging power factor for stations having no low-voltage capacitor banks or the historical low voltage power factor, whichever is more conservative. For stations having low-voltage capacitor banks, a 95% lagging power factor was assumed or the historical low-voltage power factor, whichever is more conservative. Normal planning supply capacity for transformer stations in this Region is determined by the winter 10-Day Limited Time Rating (LTR). Summer LTR ratings also were reviewed against the station load forecasts over the study period.
8. To identify emerging needs in the Region and determine whether or not further coordinated regional planning should be undertaken, the study was performed observing all elements in service and only one element out of service.
9. Transmission adequacy assessment is primarily based on, but is not limited to, the following criteria:
    - With all elements in service, the system is to be capable of supplying forecast demand with equipment loading within continuous ratings and voltages within normal range.
    - With one element out of service, the system is to be capable of supplying forecast demand with circuit loading within their long-term emergency (LTE) ratings.
    - All voltages must be within pre and post contingency ranges as per Ontario Resource and Transmission Assessment Criteria (ORTAC) criteria.
    - With one element out of service, no more than 150 MW of load is lost by configuration. Note: This criterion was put in place after the 500 kV Northeast system was built and as such, the system was not originally designed to respect this criteria for the loss of the 500 kV circuits P502X or D501P. Currently the loss of either these circuits can result in the loss of more than 150 MW.
    - With two elements out of service, no more than 600 MW of load is lost by configuration.
    - With up to two elements out of service, the system is capable of meeting the load restoration time limits as per ORTAC criteria.

6 Results

6.1 500/230kV Autotransfomers

The 500/230 kV transformers supplying the region are adequate for loss of single 500/230 kV unit.

6.2 500/115kV Autotransfomers

The 500/115kV transformers supplying the region are adequate for loss of single unit.

6.3 230/115kV Autotransfomers

The 230/115kV transformers supplying the region are adequate for loss of single unit.

6.4 Transmission Lines and Ratings

The 500kV and 230 kV circuits supplying the region are adequate over the study period for the loss of a single 500kV or 230 kV circuit in the Region.
As per section 7.2 below – the 115kV H9K circuit may experience thermal overloads and will be addressed as a bulk system issue outside of regional planning.

6.5 230 kV and 115 kV Connection Facilities

A station capacity assessment was performed over the study period for the 230 kV and 115 kV transformer stations in the Region using the station winter peak load forecast provided by the Working Group. All stations in the area have adequate supply capacity for the study period even in the event of extreme weather scenario

7 System Reliability, Operation and Restoration

7.1 Performance

The areas of Timmins, Dymond and Abitibi Canyon have experienced severe weather patterns over the last 5 years causing periodic increases of both momentary and sustained outages which have been highlighted by the IESO. The region (including the three mentioned above) does not have circuit performance outliers which would fall below customer delivery point performance standards set forth by the Ontario Energy Board.

Hydro One continually monitors performance of supply stations, and high voltage circuits and will make the necessary steps to address the problem should this issue persist.

7.2 Restoration

Depending on system conditions, the loss of P502X may result in the greatest amount of load lost through North East LR/GR special protection schemes. Based on the load levels in the study period of this assessment, load can be restored within the 30 minute, 4 hour and 8 hour time frames as required by IESO ORTAC Section 7.0. The maximum load which may be interrupted by configuration or load rejection due to the loss of two elements is up to 450MW which is below the ORTAC requirement of 600MW. (loss of P502X with D3K out of service, or vice versa)

7.3 Thermal overloading on H9K section

Under high generation scenarios, IESO has identified pre and post contingency overloads on the 115 kV circuit H9K between *Tembec SRF x H9K 127A* junction.
This is a bulk system issue which will be addressed outside of the scope of regional planning.

7.4 Congestion on D3K, A8K, A9K, H6T and H7T

Under high generation scenarios, IESO has identified there may be congestion on D3K, A8K, A9K, H6T and H7T circuits.
This is a bulk system issue which will be addressed outside of the scope of regional planning.

7.5 Kapuskasing and Calstock Area Generation

Non-utility Generator ("NUG") contracts are reaching end of term for the Kapuskasing and Calstock Generating Stations. The NUG Framework Assessment Report [1] indicated that local reliability and congestion issues may require further study as this pertains to contracted generation facilities. This is a bulk system issue which will be addressed outside of the scope of regional planning.

7.6 Outage Condition Resulting in P15/P7G/T61S radially connected to Timmins

The loss of K1K4 and K1K2 circuit breakers at Porcupine TS can result in excessive voltage declines at Timmins TS 115kV bus.
This scenario will be addressed in the next stage of regional planning.

7.7 Ansonville T2 or D3K outages

With Ansonville T2 or D3K out of service, the loss of the other can result in excessive voltage decline at Kirkland Lake TS. This scenario will be addressed in the next stage of regional planning.

8 Aging Infrastructure and Replacement of Major Equipment

Hydro One reviewed the sustainment initiatives that are currently planned for the replacement of any autotransformers, power transformers and high-voltage cables. during the study period. At this time the major committed system investments are;

Dymond TS (T3/T4) transformers (2016)
Kirkland Lake TS (T12/T13) transformers (2017)
Timmins TS (T63/T64) with single 83MVA (2016)
Otto Holden TS (T3/T4) autotransformers, and 115kV circuit breakers (2019)

9 RECOMMENDATIONS

Based on the findings and discussion in Section 6 of the Needs Assessment report, it is further recommended that voltage regulation issues at Timmins TS and Kirkland Lake TS be best addressed by wires options solution thru local planning led by Hydro One:

10 NEXT STEPS

Based on the findings of the Needs Assessment, the Working Group recommends that no further regional coordination is required and the two voltage regulation needs identified in Section 7 be further assessed as part of Local Planning to be entitled:

<u>Timmins TS / Kirkland Lake TS – Voltage Regulation Issues</u>

11 REFERENCES

i) Planning Process Working Group (PPWG) Report to the Board: The Process for Regional Infrastructure Planning in Ontario – May 17, 2013

ii) IESO 18-Month Outlook: March 2014 – August 2015

iii) IESO Ontario Resource and Transmission Assessment Criteria (ORTAC) – Issue 5.0

12 ACRONYMS

BES	Bulk Electric System
BPS	Bulk Power System
CDM	Conservation and Demand Management
CIA	Customer Impact Assessment
CGS	Customer Generating Station
CTS	Customer Transformer Station
DESN	Dual Element Spot Network
DG	Distributed Generation
DSC	Distribution System Code
GS	Generating Station
HVDS	High Voltage Distribution Station
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Planning
kV	Kilovolt
LDC	Local Distribution Company
LTE	Long Term Emergency
LTR	Limited Time Rating
LV	Low-voltage
MW	Megawatt
MVA	Mega Volt-Ampere
NERC	North American Electric Reliability Corporation
NGS	Nuclear Generating Station
NPCC	Northeast Power Coordinating Council Inc.
NA	Needs Assessment
OEB	Ontario Energy Board
ORTAC	Ontario Resource and Transmission Assessment Criteria
PF	Power Factor
PPWG	Planning Process Working Group
RIP	Regional Infrastructure Planning
SIA	System Impact Assessment
SS	Switching Station
TS	Transformer Station
TSC	Transmission System Code
ULTC	Under Load Tap Changer

Atlantic Power Interrogatory # 3

Reference:

Application Summary:

8. The total cost of the transmission line facilities for which Hydro One is seeking approval is approximately $15.1 million. The details pertaining to these costs are provided at Exhibit B, Tab 7, Schedule 1, Table 1.

9. Coincident with the transmission line upgrade, work will also be carried out at Kapuskasing TS to install a 10 Mvar capacitor bank and reactor. The transmission-related cost of the station work is estimated to be approximately $6 million.

Interrogatory:

a) The evidence indicates that the "transmission-related cost of the station work" is approximately $6 million. Please identify any and all other costs associated with the station work, whether or not "transmission-related".

Response:

a) The total cost of the transmission station work is currently estimated to be $6 million. This includes all transmission-related costs, i.e., there are no distribution costs or capital contributions to complete this Project.

Atlantic Power Interrogatory # 4

Reference:

Exhibit B, Tab 2, Schedule 1, lines 4 – 9

Preamble:

"The Independent Electricity System Operator ("IESO") has identified that increased power transfer limits across H9K will be required to supply Kapuskasing area loads during times of high hydroelectric generation and as a result of the inability to rely on local generation facilities as a firm generation source. This increased power demand causes sections of the H9K circuit to become overloaded. Consequently, the circuit needs to be upgraded as well as associated station facilities."

Interrogatory:

a) Given that the IESO materials filed on the public record do not identify high hydroelectric generation as a factor requiring increased power transfer limits across H9K, on what basis does Hydro One cite high hydroelectric generation as a factor?

b) On what basis does Hydro One conclude that it cannot rely on local generation facilities as a firm generation source? Did Hydro One consult with local generators? If no, why not?

c) But for recontracting, is there a reason (technical or otherwise) that existing generation sources cannot be relied upon beyond June 2020?

Response:

a) Please refer to Attachment 1 of Exhibit I, Tab 1, Schedule 1.

b) Please refer to Attachment 1 of Exhibit I, Tab 1, Schedule 1. To clarify, Hydro One does not complete these activities, but relies on the IESO's determination.

c) Please refer to the Needs Assessment completed by the IESO that explored the technical and economical merits of three options including the recontracting of existing generation sources found at Exhibit B, Tab 3, Schedule 1, Attachment 1.

Atlantic Power Interrogatory # 5

Reference:

Exhibit B, Tab 3, Schedule 1, Attachment 1

Interrogatory:

a) Hydro One relies on the IESO H9K Upgrade Evidence for the conclusion that the transmission line upgrades must be in-service no later than June 2020. Without recontracting of existing generation in the area, how does Hydro One plan to deal with possible delays to the in-service date of the transmission line upgrades?

b) Did Hydro One (or the IESO) determine the date at which the transmission line upgrades would be required in the event that the local generation facilities contracts are extended beyond 2020? If yes, when would the upgrade be required if the contracts could be economically extended indefinitely? If not, why was this option not explored?

c) Please provide all assumptions made by Hydro One (or the IESO) in calculating the total costs of Option 3, including:
   i. the assumed term of any new generation contract,
   ii. the assumed pricing for such new contract,
   iii. the assumed capacity and operating characteristics of such generation,
   iv. the assumptions about which portion of the contracted price was directly attributable to meeting local reliability needs vs. which portion of the contracted price was intended to meet broader system needs,
   v. any assumptions about other costs included in Option 3 that are not directly related to re-contracting a local generation resource.

d) Did Hydro One (or the IESO) determine whether a different recontracting price / term / approach would be acceptable to the local generators that could narrow or eliminate the NPV gap between Options 3 and Option 1? Is yes, please provide details of the process and the results. If not, why was this option not explored?

e) Did Hydro One (or the IESO) assess the potential benefit of extending the existing contracts with local generators or recontracting for a period that would extend beyond the completion of the IESO's Market Renewal Project in order to determine whether the transmission line upgrades would be required under the resulting market design that may include such features as a capacity market? If yes, please provide details of the analysis and conclusions. If no, please explain why the possibility that the changes resulting from the Market Renewal Project would eliminate the need for the proposed upgrades was not considered.

f) Hydro One relies on the IESO H9K Upgrade Evidence for the conclusion that existing generation facilities in the area cannot be relied upon to meet local needs. Did Hydro One evaluate why existing generation facilities cannot be relied upon? What was its independent conclusion?

g) If the existing generation facilities can be relied upon and the H9K project is deferred, what would be the scope of work for the transmission line in 10 to 15 years based on Hydro One typical practices?

h) Hydro One relies on Section 5.0 of the IESO H9K Upgrade Evidence for the conclusion that Option 1 is the most cost effective way to meet supply capacity and voltage performance needs in the Area. Is the scope of work in Option 1 typical? Is it typical to upgrade the line with a heavier conductor and replace poles to carry the heavier conductor? If not, should the NPV calculation be based on advancing the typical work 10 or 15 years and adding the present day cost of the atypical work?

i) Did Hydro One request further information on Option 3 (of Section 5.0)? In particular, did Hydro One seek clarification on the assumptions embedded within Option 3? If so, what are they? If not, why not?

j) Did Hydro One collect data relating to and/or perform its own analyses of annual cost values for Options 1, Option 2, and Option 3 (of Section 5.0)? If so, please provide copies with confidential info redacted. In not, please provide whatever analyses Hydro One relied on.

k) Did Hydro One consider non-economic benefits (e.g., socioeconomic and First Nations benefits) in relying on IESO's conclusion that Option 1 (of Section 5.0) is the preferable option? If so, what value did it place on such benefits? If not, why not?

Response:

a) Hydro One has project controls in place to monitor and control the schedule as necessary to ensure that the in-service date is maintained.

b) If the contracts for generation facilities in the Kapuskasing area are economically extended, then the upgrades will be required after the contract expires or when circuit H9K reaches end of life, whichever comes first. The 32 km section of H9K is expected to reach end of life between 2029 and 2034.

c) The assumptions in calculating the total costs of Option 3 are provided below:

i. the assumed term of any new generation contract:

10 to 15 year contract terms were assumed based on the expected end-of-life range for the 32 km section of H9K in question.

ii. the assumed pricing for such new contract:

IESO leveraged third party cost estimates for new generation facilities and costs for similar contracted facilities in Ontario.

iii. the assumed capacity and operating characteristics of such generation:

It was assumed that a 30MW gas turbine was re-contracted and re-configured to match required operating characteristics: a high degree of operability (quick starts, rapid ramping) and a low capacity factor (< 5%).

iv. the assumptions about which portion of the contracted price was directly attributable to meeting local reliability needs vs. which portion of the contracted price was intended to meet broader system needs:

The entire contracted cost for a facility, as described in i) to iii) above, was attributed to meeting the local need.

v. any assumptions about other costs included:

The installation of the capacitor at the end of the new contract term was also included in the cost.

d) Given the significant cost difference between Option 1 and Option 3, the IESO did not determine whether different re-contracting price/term/approach would be acceptable to the local generators. When determining the costs of Option 3, the IESO considered two possible modes of operation for the re-contracted existing facility. The first was continuing the present mode of operation and the second was reconfiguring the existing facility and operating it as a quick start facility. The IESO leveraged third party cost estimates for new generation facilities and costs for similar IESO-contracted facilities in Ontario to perform this analysis. The cost of the latter was less expensive than the former but still substantially more expensive than Option 1. As a result, the IESO did not further explore a different re-contracting price/term/approach.

e) Current forecasting from the Long Term Energy Plan indicates a need for incremental capacity to emerge in the mid-2020s. This need would inform the first date of the incremental capacity auction, regardless of the timeline of the IESO's Market Renewal Project. Analysis shows that re-contracting or extending existing contracts for the time between the time of contract expiry in 2020 and the commitment time of an incremental capacity auction would be a higher cost option than the recommended Kapuskasing Area Reinforcement Project.

As per the response to Exhibit I, Tab 1, Schedule 3, the estimated NPV for a 5-year contract, assuming the existing facility operates as a quick start facility, is more than $36 million. If we assumed that the existing facility continued to operate as today for the duration of the 5 year contract, the cost would be more than $35 million.

f) Please refer to the response to question b in Exhibit I, Tab 2, Schedule 4

g) Scope of work/refurbishment activities for H9K would remain consistent with what is proposed in this application. The line would be replaced on a like-for-like basis but with a conductor that is readily available and commonly used by Hydro One at that time.

h) The scope in option 1 is typical for line refurbishment projects. It is also typical to utilize a conductor with higher thermal ampacity properties in order to address a need for higher ampacity limits as outlined by the IESO.

Pole replacements on the H9K are being triggered due the condition of the exiting poles and subject to sustainment needs and would have needed replacement, at that time, regardless of a conductor upgrade.

i) Hydro One did not seek further information on Option 2 and 3 as supply contract feasibility studies were assessed by IESO. Hydro One conducted estimates and financial analysis for Option 1.

j) Please refer to Exhibit I, Tab 2, Schedule 5 subsection i.

k) Hydro One has been directed by the IESO to install reactive support at Kapusaksing TS, and upgrade circuit H9K. During the Class EA process Hydro One did consider socio-economic effects related to the proposed project; however, no socio-economic effects were identified.

Hydro One notified the First Nation and Métis communities that were identified as having a potential interest in the project area about the H9K project (IESO Option 1) and offered to meet to discuss any interests, issues or concerns they may have. One First Nation community recently contacted Hydro One expressing interest in the Project. Hydro One met with the community and its advisors and is committed to continued engagement with the community to address any interests, issues or concerns.

Atlantic Power Interrogatory # 6

Reference:

Exhibit B, Tab 4, Schedule 1, lines 14-17

Interrogatory:

Preamble:

“Based upon the above criteria, the Project is considered non-discretionary. The Project is being undertaken at the request of the IESO and it will increase power transfer capability into the Kapuskasing area and it will support the transmission system during periods of high output from generation sources.”

a) If the local generation sources could be relied upon, would that change the categorization of the transmission line upgrade to discretionary at this time?

Response:

a) Please refer to Hydro One’s response to Board Staff Interrogatory 4.

Atlantic Power Interrogatory # 7

Reference:

Exhibit B, Tab 6, Schedule 1, lines 18-19

Interrogatory:

Preamble:

"It is reasonable to expect that [the H9K sections] will be replaced at some point in the future, even though their replacement is not currently in any existing Hydro One business plans."

a) Do transmission line upgrades of similar size and scope to the H9K project normally require special budgeting in Hydro One's business plans? If so, why is the H9K project not accounted for in the business plans? If, instead, similar projects are part of Hydro One's ordinary budget for transmission line maintenance, on what basis does Hydro One conclude in Exhibit B, Tab 5, Schedule 1 (and throughout its application) that performing the H9K project now achieves "cost synergies" and avoids "double customer and community construction impacts"?

b) How often and for how long do transmission lines go beyond their expected life? Is it reasonable to expect that H9K could outlast the 10-15 year estimate?

Response:

a) Yes, projects of this size are normally individually budgeted.

   Hydro One's business planning is for a 5-year period. Any future refurbishment activities for H9K, currently not anticipated for 10-15 years, will be budgeted at an appropriate time.

   The efficiencies and customer impacts are limited to the work on circuit H9K. Addressing IESOs thermal requirement at this time, without also addressing the condition of other Line assets would not be prudent. Estimating activities, line construction, and customer interruptions would be duplicated in the 10-15 year timeframe if Hydro One were to revisit this line section and perform sustainment work again at that time. Increasing the thermal rating will require reconductoring as explained in response to Atlantic Power Interrogatory 5h). It is reasonable practice and prudent to replace any end of life or near end of life assets as required while area customers are already on outage, and construction crews are mobilized in the area.

b) Transmission line assets age and degrade in a non-linear fashion due to a variety of factors including weather, usage, location etc. Based on the existing condition of H9K, and Hydro Ones experience with similar conductors in this region it is predicted that this section of H9K will be at end of life in 10-15 years. As this is a prediction, line assets may be utilized beyond or below their predicted life. As the predicted date approaches, asset condition will be clarified with line inspections and conductor testing to determine the likelihood of failure.

Atlantic Power Interrogatory # 8

Reference:

Exhibit B, Tab 7, Schedule 1, Pg. 2, lines 8-16

Interrogatory:

Preamble:

“Resource shortage – there is a risk of resource shortages due to multiple projects that are set to be in execution at the same time in the general area of the KAR Project. This may lead to schedule delays and additional costs.

Outage constraints – there is a risk that securing an outage will not be supported by customers in the area and this may result in schedule delays and additional costs.

Aggressive timelines – there is a risk of not meeting the in-service date due to the aggressive timelines set on the Project (14 months following the leave to construct approval).”

a) With respect each of these three risks (resource shortage, outage constraints and aggressive timelines), would contracting of the existing generation facilities on a short-term basis avoid or help to mitigate the risk or allow for more thorough review? If so, how long is needed?

Response:

a) Hydro One has the project controls in place to address these risks and does not believe that short-term generation facility contracting will assist in mitigating these risks.

Atlantic Power Interrogatory # 9

Reference:

Exhibit B, Tab 7, Schedule 1, lines 16 and 17

Interrogatory:

Preamble:

"Additionally, the H9K Project involves extra cost for multiple river crossings, access and terrain challenges such as swampy-like conditions."

a) What permits does Hydro One expect to require for work in these conditions?

b) Have those permits been obtained? If not, what is the expected time to obtain them?

c) Are there other permits needed for the transmission upgrade? What is their expected time?

Response:

a) A Class Environmental Assessment (EA) was completed for the proposed project under the *Class EA for Minor Transmission Facilities*. Temporary land rights and water/road/rail crossing permits are required for access during construction and laydown areas.

b) The Class EA for the proposed project followed the Screening Process as described in the *Class EA for Minor Transmission Facilities* and was completed in November 2017. Land rights and permits are expected to be completed by end of August 2018 (formal permits will be pending Section 92 completion).

c) No other real estate or environmental permits are required for the Project.

Atlantic Power Interrogatory # 10

Reference:

Exhibit B, Tab 11, Schedule 1

Interrogatory:

a) If Hydro One begins procurement in July 2018, and the OEB does not rule until August 2018 or later, who bears the financial risk of potentially unnecessary materials?

Response:

a) All costs are at Hydro One's risk until all necessary approvals are received from the OEB.

Atlantic Power Interrogatory # 11

Reference:

Exhibit F, Tab 1, Schedule 1, Attachment 2, Table 1

Interrogatory:

a) Are the existing Summer Long Term Emergency (LTE) Rating and Summer Short Term Emergency (STE) Rating of the H9K circuit section from Spruce Falls Power & Paper Co. Junction to Carmichael Falls Junction known, assumed or estimated?

b) If known, explain how. If assumed, provided the basis for such assumptions. If estimated, detail the estimation methodology.

c) Could further study and/or analysis potentially reveal that the listed ratings of 290 A are lower than the actual ratings?

d) Would LTE and STE ratings higher than 290 A technically facilitate reliance on existing biomass generators in the area?

Response:

a) LTE and STE values are known as the H9K conductor cannot be loaded to higher thermal levels beyond the continuous rating.

b) These are known based on line surveys.

c) No. There are no additional studies that can be done to further verify the line ratings. LIDAR surveys and engineering analysis on those surveys has been completed.

d) Reliance of generators in an area requires a broad system study and their incorporation in the transmission system is not solely dependent on LTE and STE line ratings of the the directrly connected circuit. That assessment has been completed by the IESO. Please refer to Exhibit I, Tab 1, Schedule 2, Attachment 1.

Atlantic Power Interrogatory # 12

Reference:

Ontario Energy Board Notice of Application and Hearing dated April, 4, 2018 (the "**Notice**")

Interrogatory:

a) The Notice prescribes three issues for the OEB's consideration, including the promotion of the use of renewable energy sources in a manner consistent with the policies of the Government of Ontario. Is the Kapuskasing Reinforcement Project being constructed for the purpose of promoting the use of renewable energy sources in a manner consistent with the policies of the Government of Ontario?

Response:

a.) As per section 96 of the OEB Act, the OEB shall only consider the following when, under subsection (1), it considers whether the construction, expansion or reinforcement of the electricity transmission line or electricity distribution line, or the making of the interconnection, is in the public interest:

- The interests of consumers with respect to prices and the reliability and quality of electricity service.

- Where applicable and in a manner consistent with the policies of the Government of Ontario, the promotion of the use of renewable energy sources.

Hydro One's Kapuskasing Area Reinforcement Project takes into account all these items. With respect to the latter, and the focus of this interrogatory, please refer to the response to Board Staff Interrogatory 6b and Atlantic Power Interrogatory 1b.