Hydro One Networks Inc.
7th Floor, South Tower
483 Bay Street
Toronto, Ontario M5G 2P5
www.HydroOne.com

Tel: (416) 345-5240
Fax: (416) 345-5866
cell: (416) 903-5240
oded.hubert@HydroOne.com

Oded Hubert
Vice President
Regulatory Affairs

BY COURIER

June 19, 2015

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

Dear Ms. Walli:

EB-2013-0421 – Hydro One Networks Inc. Section 92 – Supply to Essex County Transmission Reinforcement Project – Hydro One Networks' Responses to CME's Questions

I am attaching two copies of Hydro One Networks' responses to the questions contained in CME's letter dated May 29, 2015 in the above-noted proceeding.

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

Sincerely,

ORIGINAL SIGNED BY ODED HUBERT

Oded Hubert

Att.

c/ Intervenors of Record (EB-2013-0421)

CANADIAN MANUFACTURERS & EXPORTERS (CME)
RESPONSES TO TECHNICAL CONFERENCE QUESTIONS

Interrogatory

Preamble

The questions which follow seek elaboration and clarification of many of the responses Hydro One has provided to Interrogatories seeking a better description of the transmission and distribution cost allocation methodologies which it is asking the Board to approve in this proceeding. What we seek is a clear step-by-step description of each of the proposed transmission and distribution methodologies so that, if they are approved, then it will be readily apparent to all stakeholders how these methodologies are to be applied in future cases.

We do not propose to list all of the Interrogatories in which questions of this nature have been posed. As a result of information provided in response to such questions, the steps which we envisage are involved in applying the proposed methodology at the transmission level include a consideration of the following questions:

(a) Is/Are there any capacity or other problem(s) with the transmission system?
(b) What is/are the cause(s) of the problem(s)- is it customer demand or other causes?
(c) What customer(s) are the cause of the problem(s) in whole or in part- is it a particular customer or sub-set of customers; or all of the customers in a region?
(d) Who benefits if the problem(s) is/are fixed- is the beneficiary constituency broader than the constituency which is causing the problem(s)?
(e) What are the costs of the alternative(s) to fix the problem(s)?
(f) What is the value of the benefits to each of the components of the beneficiary constituency which benefits from having the problem(s) fixed; and how is the value of those benefits to be derived?
(g) How are the costs of fixing the problem(s) to be apportioned among those who benefit from having the problem(s) fixed? In particular, how is the cost and benefit information to be used to derive the appropriate allocation factor in a particular case?
(h) Once costs have been apportioned, then what are the capital contribution consequences of that apportionment?

For the purposes of the elaboration and clarification questions which follow, we have assumed that the foregoing is illustrative of the step-by-step process that Hydro One follows.

Our elaboration and clarification questions have also been framed in the context of the six (6) cost allocation principles adopted by the Federal Energy Regulatory Commission ("FERC") in its Order 1000 dated July 21, 2011. We provided parties with the internet link to that material by email dated May 21, 2015. In that material, at page 449, FERC describes the "beneficiary pays" principle as " ... a cost allocation principle that includes as beneficiaries those that cause costs to be incurred or that benefit from a new transmission facility." (emphasis added)

Our elaboration and clarification questions also seek clarification of the extent to which, if at all, the proportional benefits allocation methodology, which Hydro One is asking the Board to approve, considers and/or applies the cost allocation concept which the National Energy Board ("NEB") applies to certain types of natural gas transmission expansion facilities. This "cost causation" concept is discussed in the NEB Decisions which we circulated with our letters of April 30 and May 12, 2015 (see, for example, excerpts from the NEB Decision in GH-5-89 enclosed in our April 30, 2015 letter at sections 2.2.3 and 2.3). The concept is that the need for expansion of an integrated system arises when the total demand for service exceeds the existing capacity. Existing users of the system can be considered to be equally responsible for causing a need for additional facilities since, if they were to reduce their levels of use, capacity would be freed-up and less expansion would be necessary.

Having regard to the foregoing preamble, would Hydro One and/or the Independent Electricity System Operator ("IESO") please provide responses to the following questions in advance of the Technical Conference scheduled for June 5, 2015.

1. Does the foregoing preamble contain a reasonable generic step-by-step description of the questions which are to be considered in applying the transmission cost allocation methodology which the Board is being asked to approve in this case? If not, then please provide a corrected version thereof.

Hydro One agrees that CME's "a" to "h" listing in its Preamble represents a reasonable generic step-by-step description of the questions which are to be considered in applying Hydro One's proposed transmission cost allocation methodology. Hydro One has taken the liberty of rephrasing the questions where appropriate, to more closely reflect the proposed methodology.

The remainder of this response utilizes the "corrected" questions and answers them, as requested in Question 7.

(a) Is/Are there any capacity or other need(s) with the transmission system?

There are two regional planning needs identified in the Windsor-Essex area – a supply capacity need in the Kingsville-Leamington area and a restoration need (based on the application of the Ontario Resource and Transmission Adequacy Criteria "ORTAC"), pertaining to the J3E/J4E sub-system which covers nearly the entire Windsor-Essex region.

(References: Exhibit B, Tab 4, Schedule 4, p.7, Table 1.
Transcript, Technical Conference, page 14, lines 1 – 9).

(b) What is/are the driver(s) of the need(s)—is it customer demand or other drivers?

As identified in response to (a) above, the drivers are both customer demand and overall transmission system needs.

(c) Which customer(s) are driving the need(s) in whole or in part—is it one or more customers or the overall transmission system?

Customers in the Kingsville-Leamington area are driving the need for greater supply capacity. Restoration requirements on the 115 kV system in the Windsor-Essex area are driving the system need for the investment.

(d) *Who benefits?*

A benefit is received if and only if one's needs are addressed. The benefitting parties, if both needs are addressed, are the customers in the identified area (need for supply capacity), and the transmission customer pool (restoration need).

(e) What are the costs of the alternatives to address the needs of customers and the overall transmission system, separately and together?

Table 1.0 below shows two scenarios with their associated costs, if the two identified needs were addressed in isolation and then, together.

Table 1.0

Scenario	Solution	Cost ($M)
A. If Two Needs Are Addressed Separately:		
a) Restoration need	Transmission restoration package	22.5
b) Supply capacity need	SECTR project	77.4
Total Cost for Scenario A		**99.9**
B. If the Two Needs Are Addressed Together:	SECTR project	77.4
Total Cost for Scenario B		**77.4**

*(References: Exhibit B, Tab 4, Schedule 4, pages 8-9.
Technical Conference Transcript, page 14, line 10 to page 15, line 14.)*

(f) What is the value of the benefits to each of the components of the beneficiary constituency which benefits from having the needs addressed; and how is the value of those benefits to be derived?

The benefit is quantified as the cost of the minimum investment to separately address the need. In this case, as stated in response to (e) above, the cost of the minimum investment to address the transmission system restoration need is $22.5M and the cost of the minimum investment to address the supply capacity need is $77.4M. Accordingly, the proportionate benefit to the transmission pool is 22.5% ($22.5M / $99.9M), while that to customers is 77.5% ($77.4M / $99.9M).

(References: Exhibit B, Tab 4, Schedule 4, pages 8-9. Technical Conference Transcript, page 16, lines 3 - 13.)

(g) How are the costs of addressing the needs to be apportioned among those who benefit? In particular, how is the cost and benefit information to be used to derive the appropriate allocation factor in a particular case?

The proposed methodology already sets out the approach for allocating costs (based on proportional benefits); the expectation is that the proposed methodology, or some other clear rules, will eventually be codified to provide transmitters and customers with certainty going forward.

(Reference: Technical Conference Transcript, page 117, line 27 to page 118, line 15.)

(h) Once costs have been apportioned, then what are the capital contribution consequences of that apportionment? What are the capital contributions required to be paid by customers?

Applying the percentages derived in response to Question 1(f) to the SECTR project cost of $77.4M results in $17.6M allocated to the transmission pool and $60M to the benefitting customers in the area (Hydro One Distribution, E.L.K. Energy, Entegrus, Essex Powerlines and their customers) as stated in Slide 3 “Approach B: Pool & Customer Pays -- Proportional Benefit – Proposed (Without Kingsville Cost Reduction)” of Mr. Young’s Presentation 3.

Slide 4 “Approach B: Pool & Customer Pays -- Proportional Benefit – Proposed (With Kingsville Cost Reduction - $6M)” of the same presentation then shows a reduction of $6M from the station facilities cost which results from reduced sustainment work at Kingsville TS. This $6M savings to the transmission pool is subtracted from the station facilities cost of $32.1M, resulting in a station facilities cost of $26.1M, which, when allocated using the 77.5/22.5 proportional split, then results in an allocation of station facilities cost of $20.2M to customers and $11.9M to the transmission pool. When these costs are added to the transmission line facilities costs for each party (which remain the same), the result is a $55.3M cost to customers and a $22.1M cost to the transmission pool. (Please also see the transcript, page 18, line 17 to page 20, line 7.)

The project costs of $55.3M allocated to the customers are apportioned according to each customer's incremental capacity as a portion of the total incremental capacity.

Then, using the discounted cash flow-based economic evaluation methodology, the capital contributions required from the beneficiaries are determined, as shown in the table from Mr. Satchell's presentation, below (re-named Table 2.0 for later ease of reference):

Table 2.0 Allocation [of Capital Contribution] to Customers

Capital Contribution ($M)	Line Pool	Transformation Pool	**Total**
Distribution to Transmission	31.2	8.2	39.4

Allocation to Distributors ($M)	Line Pool	Transformation Pool	**Total**
Hydro One Distribution	26.3	6.0	32.3
Essex Powerlines	2.2	0.5	2.7
E.L.K.	1.8	0.2	2.0
Entegrus	0.3	0.1	0.4
Total Allocation	**30.7**	**6.8**	**37.4**
Unallocated Capital Contribution	0.5	1.4	2.0
Total	**31.2**	**8.2**	**39.4**

Hydro One Distribution New ST Customers Allocation ($M)	Line Pool	Transformation Pool	**Total**
New ST Customers	**12.1**	**0.6**	**12.7**

Hydro One Distribution's total capital contribution includes $32.3M and the unallocated portion of $2.0M, for a total of $34.3M.

(Reference: Technical Conference, Presentation 4, slide 4).

(i) [Added] Are the benefiting customers prepared to pay the required capital contributions to proceed?

This will be determined at the stage of CCRA execution (once the beneficiaries' final forecasts have been provided and factored into the methodology).

(Reference: Technical Conference Transcript, page 214, lines 12-19).

2. By reference to each of the six (6) principles adopted by FERC in its Order 1000 dated July 21, 2011, discussed at pages 420 and following of that Order, please elaborate on whether the proposed methodology is or is not compatible with each of those principles. If the proposed methodology is not compatible with any of those

principles, then please explain why those particular principles are not applicable to the electricity transmission system in Ontario.

Hydro One has not analyzed the compatibility of its proposed methodology with the principles adopted by FERC in its Order 1000. The Board, however, may wish to consider the merits of other jurisdictions' cost allocation methodologies, if submitted in evidence by other intervenors. As indicated by Mr. Young on page 18 of the Technical Conference transcript, the IESO and Hydro One developed and proposed a cost allocation methodology that they believe is consistent with the Board's suggested emphasis on the "beneficiary pays" principle that underlies the supplementary proposed amendments to the Transmission System Code ("TSC"). Hydro One also believes that the proposed Approach B, as provided in Exhibit I-P2, Tab 2, Schedule 7, in comparison to the existing TSC and the proposed amendments, is preferable, as it reduces "free ridership". As discussed by Mr. Young, on page 21, lines 4-14 of the transcript:

> "So I know the capital contribution part is near and dear to everybody, so to summarize, I've provided a table here which shows the capital contributions as broken down into lines and stations and the total for the three approaches. And the SECTR approach is the approach B.
>
> We believe that perhaps A and C is not as appropriate, simply because in one or the other there is some degree of free ridership by one party or the other. And we believe that the SECTR proposal, you know, is fair and clear and relatively straightforward to apply, you know. Both parties benefit, so both should pay."

3. In determining the "causes" of the transmission system problems in this particular case, to what extent, if any, is the NEB cost causation concept described above applied? Please elaborate on the extent to which this concept is not applicable in the transmission cost allocation methodology which the Board is being asked to approve in this proceeding.

Hydro One has not analyzed the compatibility of its proposed methodology with the NEB's cost causation concept, but, as indicated in response to Question 2, has used an approach that is consistent with the Board's emphasis on the "beneficiary pays" principle.

4. Please provide a complete description of how the methodology which the Board is being asked to approve operates to identify all those who benefit from having the problems in this particular case fixed as Hydro One proposes.

As stated in response to Question 1d), if a need is addressed, the receiver is a beneficiary. Exhibit B, Tab 4, Schedule 4, p. 7, Table 1 identifies the two needs that will be addressed by the SECTR solution: the need to minimize the impact of supply interruption in the J3E-J4E subsystem (described elsewhere as the need to increase restoration capability in the subsystem) and the need for additional capacity to meet electricity demand in the Kingsville-Leamington subsystem. The table also identifies two additional benefits of the SECTR investment: the benefit of reducing limitations on the operation of Brighton Beach GS (or other generation connected at Keith TS) and the benefit of enabling the connection of additional distributed generation in the Kingsville/Leamington area.

The IESO and Hydro One developed integrated plans to address the two identified needs. The IESO and Hydro One have also proposed a cost allocation methodology, which the IESO and Hydro One believe is consistent with the Board's suggested emphasis on the "beneficiary pays" principle, including the proposed new section 6.3.8A of the TSC. The proposed cost allocation methodology emphasizes the beneficiary pays principle by identifying which groups of ratepayers benefit from the SECTR project's addressing of the two needs. Costs were not allocated based on the two additional benefits shown in Table 1 because the IESO and Hydro One would not, based on their planning criteria, have recommended the SECTR project to deliver either or both of these additional benefits. Moreover, in the case of the benefit of reducing limitations on the operation of Brighton Beach GS, the cost of delivering this benefit is in any event subsumed in the costs allocated to transmission ratepayers, since the $22.5 million cost of addressing the restoration need in isolation would deliver this benefit.

5. Please provide a complete description of how the proposed methodology operates to quantify the benefits which each component of the beneficiary constituency will realize in this case by having the problems fixed as Hydro One proposes. How are the benefits quantified?

As noted in response to Question 1(f), the value of the broader system benefit for addressing the restoration need in the J3E-J4E sub-system was quantified by reference to the avoided cost to the pool for addressing this need in isolation. The avoided cost of the package of three upgrades to the J3E/J4E transmission path is $22.5M.

The value of the customer benefit for addressing the need for additional capacity to meet electricity demand in the Kingsville-Leamington sub-system is the $77.4M cost of the SECTR project, because SECTR is the lowest cost solution to address this need in isolation.

Please also see Exhibit I-P2, Tab 1, Schedule 5.

6. The responses to OEB Interrogatories 5 and 11, E3 Coalition Interrogatories 5 and 6, and others indicate that Hydro One has not taken into account all of the benefits which will be realized by installing the proposed facilities. Please assume that these benefits are to be taken into account. Under this assumption, how should these benefits be valued and are these benefits being realized by all customers in a

region, or only by a particular sub-set of customers in that region? What is the proportional benefits allocation outcome of taking all of these benefits into account?

Please see the response to Question 4, above. All the benefits have been identified and properly accounted for, as per Exhibit B, Tab 4, Schedule 4, page 7. The cost allocation was based on addressing the two driving needs for the SECTR investment based on planning criteria.

7. By reference to the step-by-step description of the methodology contained in the Preamble or to a corrected version thereof provided by Hydro One in response to question 1 above, please provide a step-by-step description of the cost allocation methodology Hydro One is asking the Board to approve for allocating and recovering costs at the distribution level. Is the methodology being proposed at the distribution level a proportional benefits allocation methodology?

The cost allocation methodology is provided in Exhibit B, Tab 4, Schedule 5. Hydro One has also clarified the step-by-step description in the Preamble in response to Question 1. Hydro One considers the methodology proposed at the distribution level to be a proportional benefits allocation methodology.

8. Please provide a schedule which will illustrate the outcome, in this particular case, of applying the proposed proportional benefits allocation methodology at the distribution level to Hydro One Distribution. What proportion of the transmission costs allocated to Hydro One are in turn apportioned to all of its distribution customers as opposed to a particular sub-set of those customers?

The portion attributed to all of Hydro One's distribution customers, recoverable through their rates, is \$21.6M -- Hydro One Distribution's total capital contribution allocation of \$34.3M (\$32.3M + \$2.0M of unallocated contribution) less the estimated capital contribution of \$12.7M from new ST customers. Please refer to Table 2 provided in the response to Question 1(h) for the supporting data.

9. What would be the estimated outcome of applying the proportional benefits allocation methodology at the distribution level in this case under the auspices of a hypothetical assumption that Hydro One is the sole distributor serving all of Ontario? What proportion of the total transmission costs allocated to Hydro One Distribution, in this scenario, would in turn be allocated to all of Hydro One's distribution customers as opposed to a particular sub-set of those customers?

Hydro One has not responded, as CME has decided that it does not require an answer to this hypothetical question at this time.

10. Please particularize the changes that will need to be made to the Transmission System Code ("TSC") if the Board approves the transmission cost methodology which Hydro One is proposing in this case.

Hydro One is not prepared at this time to particularize possible changes to the Transmission System Code. Hydro One believes that particular changes to the Transmission System Code would be dealt with and developed during a separate consultation after the SECTR proceeding has concluded (assuming that the Board decide to codify this methodology, and depending on situations where the Board determines it should be applied).

11. Please particularize the changes that will need to be made to the Distribution System Code ("DSC") if the Board approves the distribution cost allocation methodology which Hydro One is proposing in this case.

Hydro One is not prepared at this time to particularize possible changes to the Distribution System Code, but would be pleased to participate in a separate consultation on this issue after the SECTR proceeding has concluded. Hydro One believes that such a consultation should include:

a) the question of the pass-through of upstream costs to embedded distributors, and to their customers.

b) depending on how question a) is resolved, the question of whether the definition of incremental load at the distribution level would, for economic evaluation purposes, be addressed using the approach in Appendix 5 of the TSC (that is, it includes not only new load, but also, any overload that is transferred to the new or modified facility, for which revenue credit would be applied in the DCF process),

c) similarly, if the TSC Appendix 5 approach discussed above, were codified in the DSC for the allocation of *transmission* costs to distribution customers, then should the same approach be used for the allocation of related *distribution* costs, and

d) the apparent discrepancy between the Transmission System Code and the Distribution System Code in the treatment of costs attributable to generators when they are beneficiaries of investments in both systems.