HYDRO ONE INTERROGATORIES

M-HYDRO ONE-1

Reference: Exhibit M, Page 7 and Curriculum Vitae

Preamble: PEG describes and lists various North American energy utility productivity and statistical benchmarking work it has performed.

Interrogatories:

a) For each of PEG's electric utility studies in the last five years, please provide a table that shows the target utility, industry (G, T, D, or combination thereof), PEG's client in the proceeding, PEG's MFP industry trend finding, PEG's benchmark finding, PEG's recommended productivity factor, and PEG's recommended stretch factor. In cases where PEG only provided some but not all the elements above, please leave blank only those elements that PEG did not perform.

Response:

The following response was provided by PEG.

a) Please see Exhibit N/Tab 1/Schedule 1/Attachment 1 for the requested information.

M-HYDRO ONE-2

Reference: Exhibit M, Page 8

Preamble: PEG states that it is not clear to it that Hydro One will face comparable productivity growth challenges as those faced by U.S. transmitters during the sample period.

Interrogatories:

a) What specific productivity growth challenges, if any, will Hydro One not face in the next few years that U.S. transmitters did face? Please explain.

b) Does PEG accept that it is possible Hydro One Transmission may in fact face equal or more productivity growth challenges than those faced by U.S. transmitters during the sample period due to challenges resulting from items such as geomagnetic disturbances, increased cybersecurity, distributed generation, and other challenges?

c) Does PEG have any specific factual information on these points regarding the productivity growth challenges faced by Hydro One?

Responses:

The following response was provided by PEG.

a) Please see our response to part (b) and the response to M-SEC-2 (Exhibit N/Tab 5/Schedule 2).

b) PEG emphasizes in its evidence, at pages 19-20, that there is uncertainty concerning how the productivity growth challenges that U.S. power transmitters faced during the years of its productivity study compare to those that Hydro One will face in the next few years. It is certainly possible that the challenges Hydro One will face in the next few years will equal or exceed those that U.S. transmitters have faced in the last 15 years. However, there is reason to believe that the Company's cost pressures are less pronounced.

   - Projects to access remote renewable resources or to strengthen the performance of bulk power markets do not seem to loom large in Hydro One's capex plans, as discussed in this filing.

- Hydro One has some incentive to exaggerate its capex needs, as discussed in Section 6 of PEG's testimony.

c) Please see the response to b).

M-HYDRO ONE-3

Reference: Exhibit M, Page 8

Preamble: PEG states that due to transmitters joining ISOs and RTOs, this triggered idiosyncratic reporting of OM&A expenses for some members. PEG states, "In our view, data for some of the affected companies should be excluded from the research."

Interrogatories:

a) Which specific transmitters did PEG exclude from the sample on this basis?

b) Please provide and explain the criteria used by PEG for excluding these transmitters from the transmission benchmarking sample.

c) Were all these same utilities as listed in part (a) excluded from PEG's productivity research conducted in Québec and used to support its productivity factor recommendation of -0.62%?

d) Please confirm that idiosyncratic reporting of expenses is not a problem for a benchmarking study if those costs are shifting from other expense categories included within the benchmarking study cost definition?

e) Please provide evidence that expenses are shifting for these excluded transmitters between expense categories not included in the cost definition to/from an expense category that is included in the cost definition.

f) Are these excluded utilities the only utilities with cost impacts resulting from joining an ISO/RTO?

g) Does PEG accept that it is possible cost increases resulting from ISO/RTO membership may stem from increased requirements and costs placed on utilities as a result of being a member of an ISO/RTO?

Responses:

The following response was provided by PEG.

a) Please see the response in Exhibit N/Tab 3/Schedule 2.

b) PEG noted in Appendix Section C.1 of their report that, between 1996 and 2005, many U.S. utilities (mostly located in California, Texas, other south-central, north-central, and northeastern states) became (and have generally remained) ISO members while others (mostly located in northwest, mountain-west, and southeastern states) have not. These organizations now perform certain activities (e.g., dispatching) which were previously performed by their members. Members permit the organization to use their transmission assets and may also provide it with operation and maintenance services. Importantly, members take their transmission services from the organization. The organization bills each member for its own costs (e.g., costs incurred for dispatching) and for costs of services it purchases from transmission owners.

This restructuring of the transmission industry in certain regions complicates statistical cost research using U.S. data. For example, the costs that utilities incurred for services that they previously provided (e.g., dispatching) could decline after they joined because these activities were now performed by the organization, and these costs could tend to be lower than those of transmitters that were not ISO members. ISO members may, on the other hand, face new cost pressures. For example, tasks that the organization takes over may become more difficult, organizations may perform new tasks (e.g., market monitoring), and members may be charged for these new and expanded tasks. ISO members may also be encouraged by their ISOs to incur higher costs (e.g., more maintenance and/or capex). Costs may then grow more rapidly for members and exceed those of transmitters who are not members.

Restructuring has also caused members to report some costs differently than they did in the past. For example, costs of capital (e.g., computer hardware and software, communications equipment, and structures) which ISOs incur in system operation and bill to utilities will be recorded by the utilities as O&M expenses, whereas utilities treat costs for these kinds of capital as capital costs when they are the owners. Many vertically-integrated utilities have in the last two decades increased their reliance on unbundled transmission services to buy and sell power. Changes in how these costs were reported can affect research results.

FERC Order 668 in December 2005 changed reporting guidelines for transmission costs. Here are some examples:

- New accounts have been established for (the gross value of) Regional Transmission and Market Operation Plant. The new categories include computer hardware (382), computer software (383), communications equipment (384), and miscellaneous plant (385). Accounts 569.1-569.4 were established, under transmission load dispatching, for maintenance of these same assets. These accounts were intended chiefly for use by ISOs, but some utilities may have elected to start reporting costs in these same accounts that were previously reported elsewhere.
- Accounts 575 and 576 were established for regional market O&M expenses.
- Transmission dispatching expenses (in Account 560) were itemized, and three subaccounts were established to report utility payments for costs that ISOs bill to them:
    - 561.4 Scheduling, System Control, and Dispatching;
    - 561.8 Reliability Planning and Standards Development; and
    - 575.7 Market Facilitation, Monitoring and Compliance.

Data problems posed by transmission sector restructuring could be mitigated if reported transmission costs were appropriately itemized and utilities reported these costs consistently. However, data problems have been observed.

- The new data guidelines occasioned by FERC Order 668 did not occur until many California, Midwestern, New York, and New England utilities had been ISO members for several years. This has produced some shifts in where ISO costs are reported. As one example, a utility might have initially reported certain ISO costs as transmission by others expenses (which are excluded from our calculations) and then reported them as dispatching expenses.

- Utilities seem to have inconsistently reported ISO costs incurred *before* FERC Order 668, with some reporting them as transmission by others expenses and others reporting them as miscellaneous transmission expenses.
- ISO members do not seem to have reported their ISO costs consistently since the implementation of FERC Order 668. For example, while many members have consistently reported sizable costs for ISO services in accounts like 561.8, as directed by Order 668, many have not. This may be due in part to varied ISO policies and the peculiarities of formula rate plans.
- Some utilities seem to have reported, as miscellaneous transmission or dispatching expenses, sizable costs that other utilities report as transmission by others expenses. All of the most egregious cases involve ISO members.
- Whether or not utilities are ISO members, they have some discretion as to whether to report dispatch expenses in FERC Account 561 (Load Dispatching) under Transmission Expenses or FERC Account 556 (System Control and Load Dispatching) under Other Power Supply Expenses.

Please also see the response to HONI-13 c (Exhibit N/Tab 1/Schedule 13).

c) No. These utilities could be included in the Québec productivity work because PEG excluded problematic OM&A cost categories from their productivity calculations.

d) PEG acknowledges that idiosyncratic reporting of expenses by sampled utilities is not a problem for a benchmarking study if those costs are shifting from other cost categories that are included within the benchmarking study cost definition (i.e., if total costs, or total OM&A or total capex costs only shift within accounts in these baskets or sub-baskets, the benchmarking results will not be affected). In this case however, cost may have been shifted out of the transmission by others category that both PEG and Clearspring excluded.

e) One example of shifting expenses that would impact productivity results can be found in the footnotes to PECO's 2011 FERC Form 1. In this case, many costs assessed by an RTO that were classified as miscellaneous transmission expenses in earlier years were reassigned for subsequent years to various accounts including purchased power (a production expense), load dispatching, and regional market expenses. PECO, however, did not correct the data for earlier years. The footnote is pasted below:

Schedule Page: 320 Line No.: 97 Column: b

PECO performed a detailed review of the PJM bill charges to re-evaluate which FERC accounts would be most appropriate for the various expenses. As a result, a large portion of the PJM activity previously recorded to Account 566 is now recorded in Accounts 555, 561.4 and 561.8 beginning on January 1, 2011, which has caused a significant decrease in Account 566.

Expenses associated with PJM were recorded in the following accounts:

PJM related activity	Year To Date December 31, 2011
Account 555	$ 103,471,941
Account 561.4	93,029,392
Account 561.8	13,990,602
Account 566	3,085,249
Account 575.7	399,149
Total	**$ 213,976,333**

The impact of the cost shift to purchased power can be seen in part in how the total operation expenses for PECO decreased between 2010 and 2011 as shown below.

81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	5,571,628	5,342,899
84	(561) Load Dispatching		
85	(561.1) Load Dispatch-Reliability		60,586
86	(561.2) Load Dispatch-Monitor and Operate Transmission System		
87	(561.3) Load Dispatch-Transmission Service and Scheduling		
88	(561.4) Scheduling, System Control and Dispatch Services	93,029,392	8,468,814
89	(561.5) Reliability, Planning and Standards Development		
90	(561.6) Transmission Service Studies		
91	(561.7) Generation Interconnection Studies	570	-29
92	(561.8) Reliability, Planning and Standards Development Services	13,990,602	280,838
93	(562) Station Expenses	950,172	1,034,596
94	(563) Overhead Lines Expenses	443,545	389,787
95	(564) Underground Lines Expenses	1,696,843	3,018
96	(565) Transmission of Electricity by Others		
97	(566) Miscellaneous Transmission Expenses	3,085,249	241,335,794
98	(567) Rents	9,274,707	3,957,378
99	TOTAL Operation (Enter Total of lines 83 thru 98)	128,042,708	260,873,681

f) All of the utilities with idiosyncratic reporting that PEG considered egregious were ISO members. Other utilities may have had higher costs due to ISO membership.

g) PEG acknowledges that the costs of some transmitters may have increased on balance as a result of ISO membership.

M-HYDRO ONE-4

Reference: Exhibit M, Page 9

Preamble: PEG notes that "Clearspring did not provide itemized results for Hydro One's transmission OM&A or capital cost performance."

Interrogatories:

a) Please confirm that PEG's stretch factor recommendations are based on its total cost models and results.

b) Please confirm that the itemized results of PEG's OM&A and capital cost performance models do not impact its total cost model results. If that is not the case, please advise and explain in detail the manner in which they impact the total cost model results.

Responses:

The following response was provided by PEG.

a) PEG confirms that its total cost benchmarking results were the only benchmarking results used to inform its stretch factor recommendations.

b) This statement is confirmed. However, in PEG's view, the itemized cost performance research is quite useful for checking on the reasonableness and interpreting the results of the total cost benchmarking. Since the incremental cost of developing these models tends to be small, they are well worth the extra effort and should be a standard component of CIR empirical evidence.

M-HYDRO ONE-5

Reference: Exhibit M, Page 10

Preamble: PEG recommends a 0.75% stretch factor for Hydro One Transmission. This results from a 0.45% base stretch factor based on PEG's total cost benchmark findings and a supplemental stretch factor "adder" of 0.3% due to what PEG state to be "unusually weak cost containment incentives" that the U.S. transmitters experienced. PEG recommends a productivity factor of -0.62% based on PEG's Québec transmission research. PEG's resultant X factor recommendation is 0.13%.

Interrogatories:

a) Please explain the rationale for adding this proposed supplemental 0.3% to the stretch factor rather than to the productivity factor?

b) Please explain what analysis PEG conducted to arrive at a supplemental stretch factor value of 0.3%, and provide a copy of any such analysis that was performed when preparing PEG's report.

c) Please provide a list of the transmission utilities in the sample that are now under formula rate making and include the year they began to be under formula rate making.

d) In respect of the basis for proposing the supplemental stretch factor of 0.3%, please confirm that the main basis or rationale for this is PEG's concern relating to weak capital cost containment incentives in the U.S. transmission sample?

e) Based on PEG's MFP results on which it relies in its report, please confirm that the X-factor would effectively contain an implicit stretch equal to base productivity trend in the event the OEB were to approve a productivity factor of 0%?

Responses:

The following response was provided by PEG.

a) Please see the response to part b).

b) PEG proposes a 0.30% supplemental stretch factor for Hydro One Transmission. PEG proposed a supplemental stretch factor of at least 0.10% for Hydro-Québec Transmission in work for industrial intervenors in a recent Régie de l'énergie IR proceeding.[1]

PEG explained in Appendix Section A.1 of their direct testimony[2] that the value of a stretch factor in a rate or revenue cap index formula should reflect the expected difference between the productivity trend of the subject utility and the base productivity growth factor. This difference should reflect two considerations:

1) the cost efficiency of the utility, as measured by such methods as econometric benchmarking; and
2) the difference between the incentive power of the subject utility's incentive ratemaking ("IR") plan and that of the regulatory systems under which utilities in the study that supports the base productivity trend operated during the sample period of the study.

In considering the value that makes sense for the second of these components, PEG used the Incentive Power model they developed, over several years, with funding from various clients that have included some Canadian utilities. Their incentive power research addresses the question of how the performance improvement of utilities differs under alternative stylized regulatory systems that feature various IR features as well as systems that resemble traditional rate regulation. At the heart of their research is a mathematical optimization model of the cost management of a company subject to rate regulation. Results of this research were published in a recent white paper that PEG prepared for

[1] Lowry, Mark N., "Transmission Productivity and Benchmarking Study," filed in Régie de l'énergie, R-4167-2021, as exhibit C-AQCIE-CIFQ-0009, 15 February 2021.

[2] Exhibit M, pp. 78-79

Lawrence Berkeley National Laboratory.[3] This report is provided as Attachment 1 to DRC-2 (Exhibit N/Tab 2/Schedule 2/Attachment 1).

The research results presented in Table B-1 on page B.5 of this paper were used in PEG's supplemental stretch factor adder calculations for this proceeding.[4] The right-most column of this table reports the average annual performance improvements, under various regulatory systems, of a utility with an intermediate level of initial operating efficiency.[5]

Consider first how this research might be used in the context of the fourth generation incentive ratemaking mechanism ("4GIRM") under which most Ontario power distributors operate. This mechanism is a multiyear rate plan with a five-year term and no earnings sharing. Table B-1 indicates that a utility with an intermediate level of initial efficiency which is operating under a multiyear rate plan with a five-year term and no earnings sharing mechanism ("ESM") would achieve 1.41% average annual performance gains in the long run. Based on our decades of experience as utility industry consultants, we believe that the typical U.S. power distributor operates under a regulatory system with irregularly-timed rate cases that occur every three years on average. There is typically no ESM. Table B-1 indicates that a utility with intermediate initial efficiency which is operating under a three-year rate case cycle and no ESM would in the long run average 0.90% annual performance gains. The difference between 1.41% and 0.90% is 0.51%. Assuming that the utility is entitled to a share of the accelerated performance gains from operation

[3] Lowry, M.N., Makos, M., Deason, J., "State Performance-Based Regulation Using Multiyear Rate Plans for U.S. Electric Utilities," Ed. Schwartz, L., for Lawrence Berkeley National Laboratory, Grid Modernization Laboratory Consortium, U.S. Department of Energy, July 2017.

[4] PEG's Incentive Power model was calibrated several years ago with productivity trends that are more rapid than those typically achieved by today. However, they believe that the differences in productivity trends for utilities with different regulatory systems are still relevant.

[5] A utility with an intermediate level of operating efficiency is assumed to have a cost that is 30% above maximum achievable efficiency. This is reasonable inasmuch as in a typical econometric benchmarking studies that we have undertaken, an intermediate score is 0% whereas an unusually bad score is around 30%.

under IR, this provides a reasonable basis for the 0.30% stretch factor that the OEB assigns to distributors with average cost efficiency under 4GIRM.

In applying this analysis to the proposed CIR for Hydro One Transmission the following additional considerations arise.

- PEG believes that the performance incentives under which utilities in their recent Québec study of U.S. power transmission productivity trends operated were considerably weaker than those under which U.S. power distributors typically operate. Based on a review of the record, PEG estimates that roughly 43% of the observations in this study were for utilities operating under approved formula rates. PEG assumes that utilities not operating under formula rates filed rate cases every three years on average. Companies with an intermediate level of operating efficiency that operate under formula rates are assumed to have average annual long-run performance gains that are equal to the 0.33% average for cost plus regulation (0.00%) and a 2-year rate case cycle (0.66%). If formula rates were the only incentive problem facing sampled transmitters, their typical annual performance gain would then be (0.43 x 0.33% + 0.57 x 0.90%) = 0.65%.
- In considering the incentive power of Hydro One's proposed CIR, one could take account of the weak performance incentives that are generated by the proposed capital cost treatment. These incentives loom especially large in the case of power transmission productivity because the business is unusually capital-intensive. However, PEG noted in Appendix Section D.1 this quote from the *Rate Handbook*.

> It is insufficient to simply adopt the stretch factor that the OEB has established for electricity distribution IRM applications. Given a utility's ability to customize the approach to rate-setting to meet its specific circumstances, the OEB would generally expect the custom index to be higher, and certainly no lower, than the

> OEB-approved X factor for Price Cap IR (productivity and stretch factors) that is used for electricity distributors.[6]

PEG also noted in this Appendix Section that the OEB stated in its decision approving the first CIR plan for Toronto Hydro that

> Custom IR, unlike other rate setting options in the RRFE, does not include a predetermined formulaic approach to annual rate adjustments, it does not automatically trigger a financial incentive for distributors to strive for continuous improvement. The OEB expects that Custom IR applications will include features that create these incentives in the context of the distributor's particular business environment.[7]

PEG assumed on this basis that the incentive power standard for a utility operating under CIR is the same or stronger as that for the 4GIRM.

The difference in incentive power between 4GIRM and the typical sampled transmitter in PEG's Québec transmission study is

$$1.41\% – (0.43 \times 0.33\% + 0.57 \times 0.90\%) = 1.41\% - 0.65 = 0.76\%$$

This is 0.25% higher than 0.51% that applies to 4GIRM, and this calculation doesn't take account of the deleterious incentive impact of the ROE premium that the FERC has granted to many utilities since passage of the Energy Policy Act of 2005. Accordingly, the proposed 0.30% stretch factor adder is reasonable.

c) Please see Attachment 1 to this interrogatory (Exhibit N/Tab 1/Schedule 5c/Attachment 1) for the requested information. As the FERC often approves formula rates on an interim basis, PEG considers that the effective date of the formula rate is the point at which the FERC gives final approval of the formula rate.

d) Please see the response to part b) of this question.

e) PEG confirms this statement.

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[6] OEB, *Handbook for Utility Rate Applications*, October 2016, pp.25-26.

[7] *Decision and Order EB-2014-0116, Toronto Hydro-Electric System Limited*, December 29, 2015, p. 5.

M-HYDRO ONE-6

Reference: Exhibit M, Page 10

Preamble: PEG recommends a 0.75% stretch factor for Hydro One Transmission. In a recent report conducted on behalf of Hawaiian Electric Company ("HECO") in Docket No. 2018-0088, PEG filed a report on May 13, 2020 titled, "New X Factor Research for HECO". This research involved vertically integrated utilities (G, T, and D). PEG recommended a -1.41% X factor and a 0.22% consumer dividend on behalf of HECO.

Interrogatories:

a) Please confirm the 0.22% consumer dividend was based on PEG's statement on p. 29 that states the average of approved consumer dividends in current plans approved by North American energy regulators is 0.22%.

b) Did PEG suggest a supplemental stretch factor in that application in recognition of the weaker cost containment incentives of formula rates and/or cost of service regulation predominately found in the U.S. electric utility industry?

c) Did PEG conduct econometric total cost benchmarking research in the HECO application? If yes, please discuss the results. If no, what was PEG's assumption of HECO's cost performance in recommending a 0.22% stretch factor?

d) What time period for the MFP analysis was used as the basis for the proposed X factor of -1.41%?

Responses:

The following response was provided by PEG.

a) PEG notes that, in the recent Hawaiian Electric Co. ("HECO") PBR proceeding, the base productivity trend and stretch factor were proposed by HECO, not by PEG. It is PEG's understanding that HECO's proposed stretch factor was based on the average industry consumer dividend, as calculated by PEG.

b) No. A supplemental stretch factor was not appropriate in the HECO proceeding because the revenue cap index applied to vertically integrated electric utility services, and not just to the power transmission services where, in PEG's view, cost containment incentives are unusually weak in the United States.

c) No. The lack of a benchmarking study was one of the reasons why the average industry stretch factor made sense for HECO.

d) HECO chose to base the proposed productivity factor on PEG's empirical results for the 15-year sample period. This choice was consistent with a custom econometric MFP growth forecast prepared by PEG that is discussed in their response to M-SEC-1 (Exhibit N/Tab 5/Schedule 1). Please note that the Hawaiian commission ultimately chose a 0% productivity factor for HECO even though the revenue cap index featured GDPPI as an inflation measure and the revenue cap index had no scale escalator. In explaining its choice of a 0% value, the commission emphasized the fact that HECO would be eligible for supplemental capital revenue for major projects.

M-HYDRO ONE-7

Reference: Exhibit M, Pages 9-10

Preamble: PEG mentions in footnote 4 that it conducted research and produced a report titled, “Transmission Productivity and Benchmarking Study” in Québec in R-4167-2021 on February 15, 2021.

Interrogatories:

a) Please confirm that PEG reported two MFP trend findings that the Régie should consider, a -2.26% MFP trend based on a 15-year period (2005 to 2019) and the longer term (1996 to 2019) MFP trend of -0.62%.

b)

  i. Did PEG use the “Kahn method” or geometric decay and indexing methods in constructing the MFP trends in the Québec proceeding?

  ii. What method is the more accurate between the two, in PEG’s opinion?

c) In PEG’s Québec report on p. 6, PEG recommends a supplemental stretch factor of 0.1% if the productivity factor is based on the longer-term MFP estimate of -0.62%. Please explain why PEG’s recommended supplemental stretch factor is 0.1% in that case?

d)

  i. Please confirm that PEG found Hydro Québec’s total cost benchmarking performance to be +67% above benchmarks using a U.S. transmitter dataset and econometric total cost model during the 2017 to 2019 period.

  ii. Do the total cost benchmark results of PEG’s analysis in Québec and in this application imply that Hydro One Transmission’s total cost performance is considerably better than that of Hydro Québec?

  iii. Please provide any other total cost econometric benchmarking results that PEG has conducted and reported on involving Canadian transmitters outside of Ontario in the last five years.

e) Why did PEG not include Hydro Québec in the transmission total cost model?

f) Please confirm that PEG inserted an ISO/RTO binary variable in its OM&A benchmarking model in that Hydro Québec research. If confirmed, please explain the rationale for why it was included.

g) PEG states on p. 72 of its Québec report, “For HQT, we used only the construction cost index value for Montréal (the highest reported for Québec) out of concern the RS Means reported no values for remote areas that HQT serves which might have higher construction costs.” Clearspring and PEG both used an average of the construction cost index value in Ontario rather than the value for Toronto. Does PEG acknowledge, due to the same type of concern it outlined in its Québec report, that this treatment might similarly disadvantage Hydro One Transmission?

h) In this same proceeding in Québec, The Brattle Group produced a report on February 19, 2021 titled, “Total Factor Productivity and the X-factor for Hydro-Québec TransÉnergie. They provide on p. 38 a table of recent stretch factor decisions.

TABLE 5: SUMMARY OF RECENT STRECTH FACTOR DECISIONS

Jurisdiction	Stretch Factor	Methodology
Ontario (Hydro One Sault Ste. Marie, electricity transmission, 2019-2026)[1]	0.30%	Total cost benchmarking and judgement
Alberta (electricity and natural gas distribution, first generation plan, 2012-2017)[2]	0.20%	Judgement
British Colombia (Fortis BC Inc. (FBC) electricity distribution/transmission, Fortis BC Energy Inc. (FEI) natural gas, 2014-2018)[3]	FBC: 0.10% FEI: 0.20%	Total cost benchmarking and judgement
Massachusetts (NSTAR, electricity distribution 2018-2023)[4]	0.25% when inflation exceeds two percent	Judgement

Sources:
[1]Ontario Energy Board Decision EB-2018-0218
[2]Alberta Utilities Commission Decision 2012-237
[3]British Columbia Utilities Commission Decision, G-139-14, p. 83
[4]Massachusetts DPU 17-05 pp 394-395

i) Does this table and result align with PEG's statement in Docket No. 2018-0088, in PEG's report filed on May 13, 2020 titled, "New X Factor Research for HECO" when on p. 29 PEG states that the average consumer dividends in current plans averages 0.22%.

<u>Responses</u>:

The following response was provided by PEG.

a) This statement is confirmed. PEG stated on p. 95 of their HQT report that

> [t]he Régie has also evinced interest in the X factor that might be applicable to a future comprehensive revenue cap index. Here again there are choices, which this time include a fifteen-year PMF decline of 2.26%, a longer-term decline of 0.62%, and the 0% target that the Ontario Energy Board chose. Recollecting our discussion in Section 2 of the special circumstances of U.S. transmitters in recent years, we lack the evidence at this time to conclude that the unusually negative PMF growth of U.S. transmitters will be applicable to HQT in the five years of any succeeding MRI. The choice between such numbers would also depend on other aspects of the MRI. A more negative number would help HQT fund more capex. Capital revenue

may in some years exceed HQT's capital cost. HQT should then have less need for extra revenue for capex surges.

A more negative X would warrant consideration if the availability of supplemental capital revenue was more restricted.

b)

i. PEG used geometric decay to calculate capital cost in the HQT proceeding.

ii. The Kahn method is easy to understand and uses a capital cost specification that is more similar to that used in cost of service rate rebasings than geometric decay. The latter advantage is especially valuable when an input price differential must be calculated, as is true in many U.S. proceedings. However, the Kahn Method had limited usefulness in the recent Québec proceeding because it does not itemize the industry productivity trends that would be required in an application to HQT. The Kahn Method was used in earlier Hydro-Québec IR proceedings to identify the X factor that would have been compensatory for HQT historically since this required no itemization.

c) PEG proposed a supplemental stretch factor of "at least" 0.10% on page 6 of their February HQT report. PEG, like Clearspring, routinely reappraises its methodologies and sometimes makes changes if a better method seems warranted. When responding to an information request in the Québec proceeding to explain the proposed 0.10% supplemental stretch factor, PEG discovered that a considerably higher value was defensible.

d)

i. This statement is confirmed.

ii. Yes.

iii. The HQT transmission cost benchmarking study is the only one that PEG has performed in Canada outside of Ontario.

e) PEG was concerned about the extreme outlier status of HQT in their Québec study. There remains a concern that some important business condition(s) were not properly addressed in that study. Including Hydro-Québec in the econometric sample for the Hydro One Transmission benchmarking study would also have added greatly to the cost and time expenditure of the study. The budget for the Hydro One study was limited.

f) This statement is confirmed. PEG included an ISO dummy in their OM&A cost benchmarking model but not in their capital or total cost models.

g) PEG notes that the same capital cost levelization was used for all sampled companies. Due to unusual operating conditions it is possible that Hydro One Transmission faces special cost challenges that are not fully captured in PEG's benchmarking models. Recomputing the input price levelization to include only Toronto would have been one way to mitigate this risk. It was easier in the context of this proceeding to add a construction standards index to the model. Furthermore, the need for a "special break" in the case of Hydro One is less apparent.

h-i) Yes. Brattle's table is in rough alignment with PEG's reported 0.22% stretch factor average in the Hawaii proceeding since the average stretch factor reported in Brattle's table is 0.21%.

M-HYDRO ONE-8

Reference: Exhibit M, Page 11

Interrogatories:

Please confirm that the value Clearspring used in its study for the service area of Hydro One is the same value for Hydro One's service area that PEG used in its recent Hydro Ottawa benchmarking research in EB-2019-0261.

Response:

The following response was provided by PEG.

This statement is confirmed. Please note, however, that Hydro One was only one of dozens of companies in the econometric research sample for PEG's Hydro Ottawa study. Perfecting the value of the area variable for Hydro One was not a priority.

M-HYDRO ONE-9

Reference: Exhibit M, Page 12

Preamble: PEG mentions that cost theory and index logic support use of a scale escalator in a revenue cap index and that it would be reasonable to add a customer growth term to Hydro One's distribution revenue cap index formula.

Interrogatories:

a) Please confirm that PEG is of the opinion that it would be reasonable to escalate both OM&A and capital-related distribution revenue by a customer growth term.

b) Does PEG consider this 0.7% annual customer growth to be equivalent to an additional stretch factor if it is not included in the escalation formula?

Responses to HYDRO ONE-9: The following response was provided by PEG.

a) PEG acknowledges that it would be reasonable to escalate both OM&A and capital-related distributor revenue by a customer growth term. This could make it possible to restrict the eligibility of growth-related capex for supplemental revenue through incremental capital funding mechanisms.

b) Yes. The implicit stretch factor that may result from the exclusion of a scale escalator from a revenue cap index is discussed on pp. 75-76 of PEG's evidence.[8] However, this implicit stretch factor effectively applies only to Hydro One's OM&A revenue.

[8] Exhibit M, pp. 75-76

M-HYDRO ONE-10

Reference: Exhibit M, Page 13

Preamble: PEG raises a concern regarding C factors and that the Company can be compensated twice for the same capex: once via the C factor and then again by low X factors in past, present, and future IRMs. Later on p. 13 PEG states that utilities should not be encouraged to stay on Custom IR indefinitely.

Interrogatories:

a) Given the Ontario precedents in setting productivity factors no less than zero despite negative industry MFP trends and instituting stretch factors even after the utility being on consecutive IR plans, when does PEG anticipate that Hydro One will have a low X factor in future IRMs?

b) In PEG's view, when utilities operate under high X factors would this exacerbate the need for utilities to file under Custom IR and request C-factors since the parameters of IRM are not designed to provide the commensurate revenue growth? By "high" we mean to say X factors that are above what cost theory and indexing logic would entail.

c) If the OEB were to decide on an X factor above PEG's recommended 0.13%, would that increase the likelihood, in PEG's view, of the Company needing to file another Custom IR application in the future?

Responses:

The following response was provided by PEG.

a) PEG does not know when Hydro One's achievable productivity trend will fall below that of the industry. A 0% MFP growth target may be arbitrary for transmission but is not obviously so for distribution. It is not unusual for stretch factors to be considered in consecutive IR plans. Massachusetts is a good example.

b) PEG acknowledges that an arbitrarily high X factor would increase the need for an Ontario utility to request supplemental capital revenue by such means as a C factor. PEG also believes that utilities are likely to propose C factors even when operation without them would be challenging but achievable.

c) Yes, all else being equal.

M-HYDRO ONE-11

Reference: Exhibit M, Page 18

Preamble: PEG states that Clearspring's 2001-2019 transmission productivity trend equaled -1.66%.

Interrogatories:

a) In PEG's Québec research what was PEG's MFP trend for that same time period?

Response:

The following response was provided by PEG.

a) Using size-weighted averages, PEG reported a -1.42% MFP growth trend over this same period. There is thus general agreement between PEG and Clearspring that the productivity growth of U.S. transmitters was materially negative over these years.

M-HYDRO ONE-12

Reference: Exhibit M, Page 20

Preamble: PEG states that The Brattle Group, who represented Hydro-Québec, made an X factor recommendation of 1.04%. Later on p. 20, PEG states they found a 0.62% base productivity trend that served as the basis for its MFP trend recommendation.

Interrogatories:

a) Please confirm that The Brattle Group actually recommended an X factor of -1.04%, a negative number rather than the positive cited in PEG's report.

b) Please confirm that PEG found a -0.62% base productivity trend, again a negative number rather than the positive cited in PEG's report.

c) Please confirm that PEG also presented in its report a choice for the Régie to either base the productivity factor on the longer-run transmission productivity trend of -0.62% or the shorter MFP trend from 2004 to 2019 of -2.26%. Please confirm that PEG considered both of these to be viable or reasonable options?

Responses:

The following response was provided by PEG.

a) This statement is confirmed. Brattle recommended an X factor of -1.04% based on the average multifactor transmission productivity trend of its sampled U.S. utilities over the 25-year period from 1995 to 2019. PEG notes, however, the Brattle committed several errors in their productivity research. PEG reported in their reply evidence that when these errors were corrected, the transmission MFP growth of Brattle's sampled utilities averaged +0.09%. The difference between the MFP trend computed by PEG and the corrected MFP trend of Brattle lay chiefly in the capital cost calculation. Brattle used the one hoss shay specification that is favored these days by many utility witnesses in IR proceedings.

b) This statement is also confirmed. PEG recommended an X factor of -0.62%

based on the average multifactor transmission productivity trend of its sampled U.S. utilities over the 24-year 1996-2019 period.

c) Please see our response to M-Hydro One-7a (Exhibit N/Tab 1/Schedule 7 part a).

M-HYDRO ONE-13

Reference: Exhibit M, Pages 20-21

Preamble: PEG discusses the structural change in the industry and how ISO members began purchasing a wide range of transmission services from the agencies and that this impacted cost accounting procedures. PEG says that Clearspring's sample includes data from several companies that reported implausibly large values for dispatch-related and/or miscellaneous transmission expenses.

Interrogatories:

a) Does PEG have factual evidence in respect of what services these transmitters began purchasing from the ISOs? If yes, please provide.

b) Are these purchased services different from what Hydro One also purchases or conducts itself? If yes, please discuss and provide data per excluded utility if available.

c) What threshold did PEG use to determine what is implausibly high for dispatch-related expenses? How did PEG determine this threshold?

d) What threshold did PEG use to determine what is implausibly high for miscellaneous transmission expenses? How did PEG determine this threshold?

e) Does PEG's research fully account for the structural change in the transmission industry?

Responses:

The following response was provided by PEG.

a) PEG's main concern is that members began purchasing most of their transmission services from the ISO, including the services provided by their own systems. This is a well-known fact.

b) PEG is not in a position to know all the details of purchased services by HON nor is PEG aware of any claim by the Company that it faces unique challenges in this area that would complicate benchmarking.

c) Please see the response to M-Hydro One-3b (Exhibit N/Tab 1/Schedule 3 part b) for a discussion of PEG's general concerns with the transmission cost data of ISO members.

This discussion was based on a detailed analysis of the OM&A cost data of sampled transmitters. The spreadsheet that we used in this analysis can be found in Exhibit N/Tab 1/Schedule 13c/ Attachment 1. Please note the following.

- Many utilities reported a surge in transmission by others expenses. That is not problematic.
- Six members of ISOs or RTOs (e.g., Commonwealth Edison, Kansas Gas and Electric, Oklahoma Gas and Electric, PECO Energy, San Diego Gas and Electric, and Southern California Edison) reported sharp increases in miscellaneous transmission expenses.
- Three members of ISOs or RTOs (Commonwealth Edison, PECO Energy, and Southern California Edison) also reported sharp increases in dispatch-related expenses. These seemed to be transfers from miscellaneous transmission expenses. Many other companies reported smaller but material jumps in dispatch related expenses. The salient cause was scheduling, system control and dispatching expenses from an ISO or RTO.
- Nevada Power reported a surge in transmission rents.

Based on this analysis, PEG decided to exclude six companies (indicated in brown in the attachment) from the econometric model estimation and to exclude transmission by others, miscellaneous transmission expenses, and accounts 561.1 to 561.8 from their productivity calculations.

d) No formal threshold was used in these decisions. PEG relied upon its decades of experience to judge when screening these data. In the case of miscellaneous

O&M, Southern California Edison can serve as an example. The transmission O&M expenses increased to 458M from 260M in 2018. Net of wheeling expense an increase to 425M from 227M was noted. Miscellaneous O&M accounted for a large portion of this increase as it had almost tripled from 57M to 163M and accounted for 38% of O&M net of wheeling. It is unlikely that the 100M increase is due to a decrease in other O&M accounts because the total increased rapidly. It is also suspicious that such a large amount of O&M cost could not be properly placed in more detailed O&M accounts. This suggested to PEG that some unknown accounting issue may be the reason for the increase. The most extreme example of the questionable use of the miscellaneous account is Kansas Gas and Electric in 2019 where an astounding 92.7% of transmission OM&A cost was classified as miscellaneous.

e) PEG acknowledges that their study does not fully account for the structural changes in the U.S. transmission industry, nor are they aware of any study that does so.

M-HYDRO ONE-14

Reference: Exhibit M, Page 25

Preamble: PEG includes the construction standards index variable which Mr. Fenrick developed and used in the prior Hydro One transmission application.

Interrogatories:

a) In PEG's prior report in Hydro One's last transmission application (EB-2019-0082), PEG provided a report on September 5, 2019 titled, "Incentive Regulation for Hydro One Transmission". On p. 22 PEG mentions the construction standards variable and states, "Moreover, the accuracy of the calculation of the value for Hydro One is critically important, and we believe that PSE has misstated Hydro One's value." Did PEG use this same value in its current research or did PEG modify the value for Hydro One? If it was modified, please explain how. If it was not, please explain the rationale for PEG inserting a variable that it has previously asserted misstates Hydro One's value.

b) In EB-2019-0082, Exhibit L1, Tab 1, Schedule 7, part c, the issue of the construction standards variable was raised in an interrogatory to PEG. It stated, "In the technical conference, Mr. Fenrick (lead author of the PSE report) states that PSE examined the transmission service territory of Hydro One and that the current approach of using the retail service territory of Hydro One is a conservative one. The variable value for Hydro One is higher (i.e., more challenging) if the transmission service territory is inserted rather than the retail service territory. Given PEG's concern over this issue, please re-run the PEG model and substitute the value 0.99 for the current value for the construction standards variable for Hydro One and revise Table 5 of the PEG report." Does PEG now believe it is appropriate to use the full retail service territory of Hydro One in the construction of this variable?

c) Please confirm that if the variable is constructed using the area where transmission assets actually are rather than Hydro One's full retail service territory, that is inserting the 0.99 value rather than the lower one used by PEG, Hydro One's transmission total cost score improves by approximately 2% during the CIR period (all else being equal). If PEG cannot confirm, please provide PEG's estimate of the impact and provide details including the model used with a 0.99 value rather than the lower value for Hydro One.

Responses:

The following response was provided by PEG.

a) PEG used the value for the construction standards index that was originally assigned to this variable by Hydro One.

b) A revised version of Table 5, with a 0.99 value for HON's construction standards variable, is below. It can be seen that the alternative value has little effect on Hydro One's benchmarking score. Over the 2017-2019 period, for example, Hydro One's score only improves from 7.23% to 5.30%. PEG did not take the time to appraise the merit of the value for this variable that Hydro One claims is transmission specific.

Transmission Total Cost Performance of Hydro One

[Actual - Predicted Cost]

Year	Cost Benchmark Score
2004	-3.50%
2005	-6.48%
2006	-6.23%
2007	-4.32%
2008	-7.72%
2009	-4.99%
2010	-4.29%
2011	-3.04%
2012	1.43%
2013	-1.01%
2014	0.75%
2015	3.74%
2016	4.46%
2017	3.49%
2018	6.19%
2019	6.24%
2020	5.23%
2021	4.75%
2022	6.78%
2023	9.78%
2024	10.79%
2025	12.76%
2026	13.25%
2027	14.25%
Average 2017-2019	**5.30%**
Average 2023-2027	**12.16%**

c) This statement is confirmed.

M-HYDRO ONE-15

References: Exhibit M, Pages 27-40 and PEG Working Papers

Preamble: PEG provides its transmission econometric model and results for Hydro One Transmission.

Interrogatories:

a) Please provide a sample table displaying PEG's transmission benchmarking sample.

b) In the transmission model (Table 1) the legend key says that a percentage of overhead distribution plant variable is included. Did PEG include the percentage of overhead distribution plant as a variable in a transmission cost model?

c) There is no "ISO" variable included in the transmission cost models. Please explain why this business condition is not included as a business condition variable in PEG's transmission cost models.

d) Please confirm that if PEG includes an ISO variable as a business condition into its transmission total cost model, Hydro One's transmission total cost score improves by approximately 12% (all else being equal). If not confirmed, please provide an estimate of the impact along with details explaining the calculation including the model used to estimate the impact.

e) Please confirm that if PEG substitutes Clearspring's substation values for its own into the transmission total cost model, the benchmark score for Hydro One is essentially unchanged, i.e. less than 0.2% change (all else being equal). If not confirmed, please provide an estimate of the impact along with details explaining the calculation including the model used to estimate the impact.

Responses:

The following response was provided by PEG.

a) Here is the requested table:

PEG Transmission Econometric Sample

Alabama Power	Jersey Central Power & Light
ALLETE (Minnesota Power)	Kansas City Power & Light
Arizona Public Service	Kentucky Utilities
Atlantic City Electric	Louisville Gas and Electric
Avista	MDU Resources Group
Baltimore Gas and Electric	Mississippi Power
Black Hills Power	Monongahela Power
Central Hudson Gas & Electric	Nevada Power
Central Maine Power	New York State Electric & Gas
Cleco Power	Niagara Mohawk Power
Consolidated Edison Company of New York	Northern States Power - MN
Duke Energy Carolinas	Orange and Rockland Utilities
Duke Energy Florida	PacifiCorp
Duke Energy Indiana	Potomac Electric Power
Duke Energy Progress	PPL Electric Utilities
Duquesne Light	Public Service of Colorado
El Paso Electric	Public Service of New Hampshire
Empire District Electric	Public Service Electric and Gas
Entergy Arkansas	Rochester Gas and Electric
Entergy Mississippi	South Carolina Electric & Gas
Entergy New Orleans	Southern Indiana Gas and Electric
Florida Power & Light	Southwestern Public Service
Gulf Power	Tampa Electric
Hydro One Networks	Tucson Electric Power
Idaho Power	Union Electric
Indianapolis Power & Light	West Penn Power

b) No, this was a typo. The variable used in the transmission total cost model was the share of overhead lines in the gross value of overhead and underground lines.

c) PEG excluded the ISO variable from its models for several reasons

- We are concerned that the parameter estimate for this variable may be bolstered by a tendency of ISO members to face cost pressures, not elsewhere properly captured in the cost model, which are unrelated to ISO membership. For example, ISO members are more likely to serve areas with high input prices and urban congestion.
- The cost pressures affecting Hydro One as a result of IESO membership may differ from those of U.S. utilities that are ISO members. For

example, U.S. RTOs compete for members and this could predispose them to encourage capex.

- When Clearspring uses the variable in the context of data that features egregious reporting inconsistencies, it is effectively according Hydro One a more lenient benchmark value due to reporting idiosyncrasies that the Company hopefully did not and will not engage in.

d) This statement is confirmed. On the other hand, PEG's model includes a forestation variable, a construction standards index, and a controversial scope variable that favor the Company.

e) This statement is confirmed. While Clearspring's flawed substation variables do not materially affect Hydro One's total transmission cost benchmarking score, the quality of statistical benchmarking in OEB proceedings is nonetheless further improved by identifying errors when they arise.

M-HYDRO ONE-16

References: Exhibit M, Pages 27-40 and PEG Working Papers

Preamble: PEG's peak demand variable is labeled as ratcheted max transmission peak. By "ratcheted" it means the maximum peak demand value of all historic years of the sample or the current year is used. That is, the variable never decreases from prior years, it can only increase if the current year has a higher peak demand.

Interrogatories:

a) Please confirm that PEG only ratcheted the U.S. sample but did not ratchet the variable value for Hydro One. If confirmed, why did PEG not ratchet Hydro One's variable value?

b) Please confirm that if PEG had used the same ratchet definition for Hydro One as it conducted for the U.S. sample utilities, Hydro One's transmission total cost score would improve by approximately 13% (all else being equal). If not confirmed, please provide an estimate of the impact along with explanatory details including the model used to estimate the impact.

c) PEG used the U.S. transmission peak demand data to formulate its ratcheted transmission peak demand variable. For a few utilities, this data is reported at the holding company level rather than at the operating level. How did PEG adjust the data in those circumstances?

d) Did PEG consider removing those observations with bad transmission peak data from the sample given the inconsistent data? Why or why not?

<u>Responses</u>:

The following response was provided by PEG.

a) This is confirmed. For U.S. utilities in the sample, PEG used the ratcheted transmission peak data it calculated in the HQT proceeding and then calculated the values for additional companies as needed. However, PEG relied upon the PEAK10 variable of Clearspring for the Hydro One value, misunderstanding it to be a 10-year rolling ratchet.

b) This statement is confirmed for the CIR period. A table with full results is below.

Transmission Total Cost Performance of Hydro One

[Actual - Predicted Cost]

Year	Cost Benchmark Score
2004	-1.39%
2005	-6.66%
2006	-7.64%
2007	-5.69%
2008	-9.63%
2009	-7.25%
2010	-6.62%
2011	-5.33%
2012	-1.06%
2013	-3.45%
2014	-2.26%
2015	-0.21%
2016	-0.49%
2017	-2.52%
2018	-0.08%
2019	-0.73%
2020	-2.74%
2021	-4.32%
2022	-3.14%
2023	-1.08%
2024	-0.37%
2025	1.39%
2026	1.47%
2027	2.48%
Average 2017-2019	**-1.11%**
Average 2023-2027	**0.78%**

c) PEG adjusted the peak load values for several of the companies with problematic data. In some cases, the company specific values were available in footnotes. Where correct company specific data were never available, the proportion of the correctly reported *monthly* peaks on FERC Form 1 was used to allocate the holding company *transmission* peak to the operating companies. In a few cases, correct recent values were used as proxies for older values where correct data were not available.

d) Since the size of their transmission sample is considerably smaller than the size of their distribution sample, PEG deemed it preferable to revise the reported peak load data of these companies rather than to exclude them from the study. Mr. Fenrick included transmission peak data for these same companies in his prior transmission benchmarking study for Hydro One.

M-HYDRO ONE-17

Reference: Exhibit M, Pages 40 – 41

Preamble: PEG states that their transmission productivity research methodology in Québec was broadly similar to Clearspring's but with a few notable differences.

Interrogatories:

a) What utilities did PEG exclude in their Québec productivity trend research that Clearspring included?

b) Did PEG exclude those same utilities from its transmission total cost benchmarking research in this application?

c) Are there utilities that PEG excluded in the current total cost benchmarking research that it did not exclude in its Québec productivity research? If yes, please provide a list.

d) In Table 8, PEG states that MFP trends in the transmission industry are -0.62% for the 1996-2019 period and -2.26% for the 2005-2019 period. Given the structural change that occurred in the transmission industry in the late 1990's and early 2000's and that productivity challenges have evidently increased in recent years, does PEG acknowledge that the more recent MFP trend of -2.26% may be a reasonable choice for the productivity factor?

Responses:

The following response was provided by PEG.

a) PEG excluded six companies from their Québec econometric research which Clearspring included in their transmission research for Hydro One.

1. Commonwealth Edison
2. Southern California Edison
3. Oklahoma Gas & Electric
4. Kansas Gas & Electric
5. San Diego Gas & Electric
6. PECO Energy

b) Yes

c) The following companies were not included in Clearspring's current study but were included in PEG's Québec transmission study:

1. Connecticut Light and Power
2. Delmarva Power and Light
3. Duke Energy Ohio

PEG did not undertake the additional work needed to attempt to include them in the Clearspring database.

d) Yes. It is of course possible that the productivity trend of U.S. transmitters in the last 15 years of the sample period is an appropriate target for Hydro One in the next few years, just as it is possible that it is not.

M-HYDRO ONE-18

Reference: Exhibit M, Pages 43 – 62

Preamble: PEG provides the details of its distribution cost models and results and includes transmission line lengths as a proxy for distribution service area as an output variable into its distribution cost models.

Interrogatories:

a) On p. 45 PEG states, "In his previous work for Hydro One Distribution Mr. Fenrick used as his estimate the total area of Ontario, including water bodies." Please further examine this statement to see if the area used was Hydro One's full retail service territory, including water bodies rather than the full area of Ontario. We note that Mr. Fenrick used a value of 961,498 square kilometres in the prior study and according to World Atlas the total area of Ontario (including water bodies) is 1,076,395 square kilometres.

b) Clearspring used the reduced value of 651,974 sq. kilometres for Hydro One's service area in its current distribution total cost benchmarking research. This matched the same value PEG used for Hydro One's service area in its Hydro Ottawa benchmarking research. Please explain PEG's statement on p. 45, "This is the area of Ontario's land surface less the estimated service territory areas of other utilities." We note the sum of all of the other Ontario distribution service territories is 29,634 sq. km according to the 2019 OEB Yearbook data and the land area of Ontario is approximately 917,741 sq. kilometres.

Responses:

The following response was provided by PEG.

a) The service territory area that Mr. Fenrick relied upon in his previous work for Hydro One Distribution was greater than the total land area of Ontario and included nearly half of the area of Ontario's water bodies. Please see the response to M-Hydro One-21c (Exhibit N/Tab 1/Schedule 21 part c) for additional comments by PEG about service territory measurement.

b) PEG acknowledges that this explanation of the 651,974 sq. km service territory estimate is erroneous. The actual derivation is discussed in their response to M-Hydro One-21c (Exhibit N/Tab 1/Schedule 21 part c).

M-HYDRO ONE-19

Reference: Exhibit M, Page 45

Preamble: PEG states on p. 45, "We agree that a variable measuring the extent of distribution subtransmission lines is worthwhile. However, we don't think that the variable Clearspring used for this purpose (% of transmission lines with ratings above 50kV) is appropriate."

Interrogatories:

a) Please explain why PEG believes Clearspring's variable is not appropriate.

b) Please explain how PEG's model accounts for the extent of distribution subtransmission lines of the sampled utilities.

Responses:

The following response was provided by PEG.

a) PEG acknowledges the desirability of recognizing the amount of subtransmission work that is done by a power distributor. One concern that they had about using Clearspring's distribution work variable was that the variable is insufficiently focused on the subtransmission issue. For example, if 100% of a utility's transmission lines have a voltage exceeding 50 KV, it does not necessarily mean that it has some subtransmission lines that have been classified as distribution lines. In PEG's distribution total cost research, the parameter for this variable tended to be statistically significant. In the past PEG has attempted to use substation data to identify subtransmission effort. After early attempts were promising, improved and corrected data did not show this to be a statistically significant issue. Additional work in this area was not a priority for this project.

b) In their distribution cost models PEG used the percentage of distribution plant in the total gross value of T&D plant as a variable. This variable addresses the transmission vs. distribution classification issue as well as the T&D economies of scope issue.

M-HYDRO ONE-20

Reference: Exhibit M, Page 50

Preamble: PEG used a ratcheted peak demand variable in its distribution cost models.

Interrogatories:

a) Please confirm that PEG only ratcheted the U.S. sample but did not ratchet the variable value for Hydro One. If confirmed, why did PEG not ratchet Hydro One's variable value to be consistent with the variable definition for the rest of the sample?

Responses:

The following response was provided by PEG.

a) This is confirmed, for the same reasons as in the transmission research. PEG transferred Hydro One's PEAK10 data believing it to be ratcheted without realizing there was a problem. The data for all of the other companies was ratcheted because it was processed by PEG. Hydro One's total distribution cost benchmark score is not greatly affected when the ratcheted value is used. A table of the corrected results is below.

Distribution Total Cost Performance of Hydro One

[Actual - Predicted Cost]

Year	Cost Benchmark Score
2002	20.15%
2003	19.52%
2004	14.17%
2005	16.42%
2006	19.62%
2007	27.71%
2008	26.29%
2009	31.24%
2010	30.74%
2011	32.51%
2012	33.14%
2013	37.10%
2014	39.44%
2015	35.30%
2016	37.21%
2017	36.07%
2018	36.23%
2019	35.85%
2020	34.41%
2021	31.67%
2022	31.01%
2023	34.87%
2024	36.32%
2025	38.20%
2026	39.24%
2027	40.36%
Average 2017-2019	**36.05%**
Average 2023-2027	**37.80%**

M-HYDRO ONE-21

Reference: Exhibit M, Pages 45 - 50

Preamble: Instead of using the service area variable in its distribution cost models that PEG used in its Hydro Ottawa research and that Clearspring used in the current research, PEG instead uses transmission line length as it states on p. 49, "Lacking a good estimate of the area of Hydro One's service territory, we replaced the area variable that Clearspring used with their transmission line length variable. This variable should be highly correlated with distribution service territory and sidesteps the problem of obtaining an accurate value for Clearspring's area variable for Hydro One."

Interrogatories:

a) On what basis and factual evidence did PEG rely to make the assertion that transmission line lengths are highly correlated with distribution area? Please provide any data and/or other factual information used or relied on to support this assertion.

b) Has PEG ever included a transmission line length variable in a distribution total cost benchmarking model prior to this application? If yes, please provide the study report or reports.

c) Did PEG take any steps at all to pursue estimating what it would consider a more accurate or suitable service area estimate for Hydro One's service territory? If so, please advise what steps were taken and what preliminary results were obtained and provide copies of any material indicating the work PEG did and the results of it. If PEG did not do so, please explain why?

d) Does PEG accept that it would be preferable to use distribution area over transmission line lengths if an accurate estimate was available for Hydro One?

e) Does PEG accept that it would be preferable to use distribution line lengths over transmission line lengths if accurate data were available for both the sample and Hydro One?

f) PEG shows on p 48 that Hydro One has 3.89 times the sample average transmission km of line. The sample average for distribution service area in PEG's dataset is 24,188 sq. km. Please confirm that using PEG's transmission line lengths as the output variable is equivalent to giving Hydro One credit for a service territory of 94,091 sq. km, which is calculated by taking the sample average area of 24,188 sq. km multiplied by 3.89.

g) Is PEG of the view that 94,091 sq. km is a reasonable estimate of Hydro One's distribution service territory?

h) Please confirm that the land area of Southern Ontario, including the Parry Sound and Muskoka districts is approximately 140,000 sq. km. If not able to confirm, please provide PEG's estimate of the land area in square kilometres of Southern Ontario.

i) Please confirm that PEG acknowledges that Hydro One Distribution and other Ontario distributors also serve substantial service areas outside of Southern Ontario.

j) Please confirm that Hydro One's distribution total cost benchmark score improves by approximately 27% if instead of transmission line lengths, PEG uses the distribution land area variable that it used in its Hydro Ottawa research (all else being equal, with no other methodological changes). If not confirmed, please provide an estimate of the impact along with details explaining the calculation including the model used to estimate the impact of moving to transmission line miles from distribution land area.

Responses to HYDRO ONE-21: The following response was provided by PEG.

a) There are several reasons to expect that the correlation between transmission line miles and distribution service territory area should be high.

   - The utilities in our transmission sample were originally vertically integrated. The principal job of the transmission system was to carry power from generators to the distribution system. Most generating units were located in the utility's service territory.

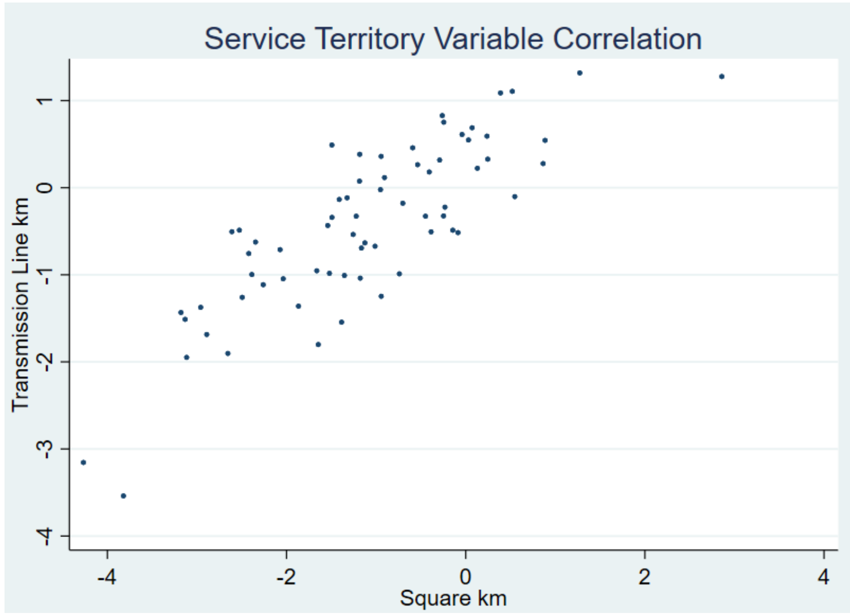
- To the extent that distribution customers are highly dispersed, as in a rural area, transmission substations to serve them will also be dispersed and transmission lines will be longer.
- If a utility provides service in rural areas between towns, it is more likely to have subtransmission lines to serve these areas. These lines are frequently treated as transmission assets.

On the other hand, the footprint of some transmission systems differs substantially from the footprint of the affiliated distribution system.

- A sizable portion of local transmission service is sometimes provided by a different company. For example, some investor-owned power distributors in the Pacific Northwest receive a sizable part of their power from the Bonneville Power Administration.
- Central generating stations are sometimes remote from populated areas and are more likely to be outside the service territory than in the past.
- Rural service between towns is sometimes provided by a distribution cooperative.

The extent of correlation between transmission line miles and service territory area is of course an empirical issue and PEG has performed two notable statistical tests to address the issue.

- PEG performed a correlation test for the values of distribution area and transmission line length. The correlation for each company's 2017-2019 average values of transmission km and square km is 0.8320, with a p-value of 0.0000. A graph of these values is presented below.



- PEG also performed a Spearman Rank Correlation test of the ranking of each sampled utility's number of customers per km of transmission line and the number of customers per square kilometer of service territory, using the average values for 2017-2019. The Spearman's rho value is 0.7875 and the result is highly significant with a p-value of 0.0000.

b) No. PEG's use of transmission line length as a proxy for distribution customer dispersion was driven in large part by the difficulty of calculating an appropriate value for the area of Hydro One. Clearspring did not prioritize developing a better area estimate, instead using PEG's estimate from a prior proceeding.

c) Yes. In the Hydro Ottawa proceeding, PEG determined that the 961,498 square km estimate of Hydro One's service territory which Mr. Fenrick used (and which exceeded the land area of the province) was implausible.

The lower value used by PEG in that proceeding was constructed by starting with Hydro One's 2014 reported service territory area of 650,000 sq. km and adding the area reportedly served by distributors that the Company acquired after that date. This was an attempt on the part of PEG to obtain a more reasonable estimate of the licensed service territory of Hydro One Distribution.

The optimality of area as a scale measure was not considered. It was unknown at the time exactly what areas were covered by this lower value.

In the current proceeding, PEG examined the official service territory maps provided on the OEB website Ontario Electricity and Natural Gas Utilities - Service Area Map | Ontario Energy Board (oeb.ca) and considered their use to obtain a better estimate of the service territory actually served by Hydro One Distribution. PEG was unable to find a straightforward way to do this from these maps. Their review revealed that vast areas of Ontario are lightly populated and unserved by any distributor. PEG attempted to determine what land area their previous area estimate would cover to determine if it contained very large unserved areas.

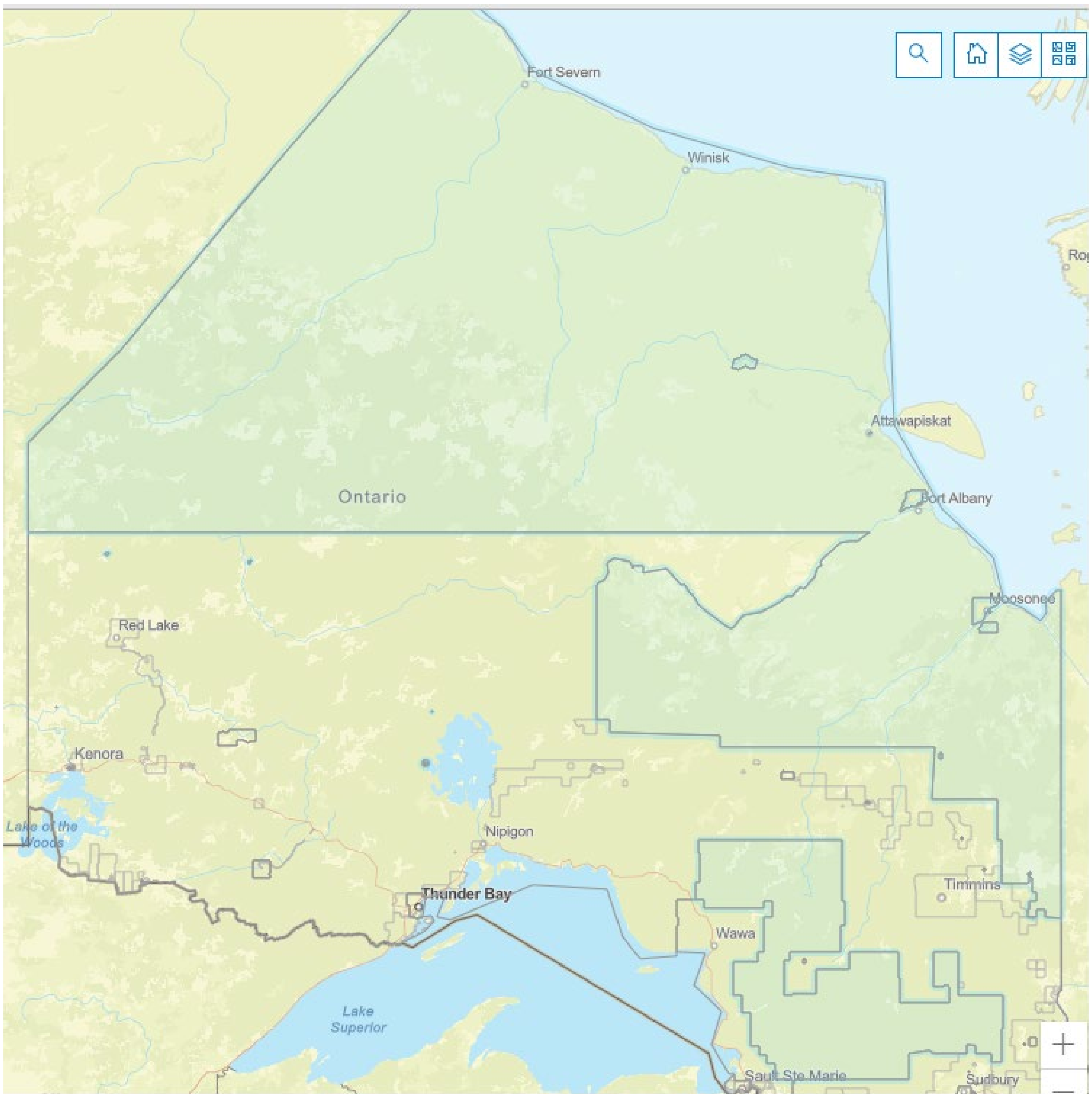
1. Hydro One currently reports an area of 961,498, which is significantly higher than the area reported by the Company in 2014. A possible explanation for the large difference between these values is that the area that Hydro One Remote Communities stands ready to serve was not reported in the earlier OEB Electricity Yearbook and that this area is included in the more recent and higher area estimates.
2. The current Hydro One RRR value versus what PEG used in the Hydro Ottawa proceeding implies that the size of Hydro One Remote Communities service territory is about 300,000 square kilometers. This seems plausible from looking at the maps.
3. If this is the case, then the Hydro One service territory on the OEB map has an area of around 650,000 sq. km.

The service territory maps of Hydro One and Hydro One Remote Communities are provided below from the OEB map source cited above.

Hydro One:


Ontario
Port Albany
Moosonee
Red Lake
Kenora
Matagami
Nipigon
Thunder Bay
Timmins
Rouyn-Noranda
Wawa
Lake Superior
Sault Ste Marie
Sudbury
North Bay
Minnesota
Ottawa
Minneapolis
Lake Huron
Wisconsin
Owen Sound
Barrie
Kingston
Toronto
Lake Ontario
Michigan
Hamilton
Rochester
Madison
Milwaukee
Grand Rapids
Sarnia
London
Buffalo
New York
Lansing
Detroit
Iowa
Lake Erie
Chicago
Des Moines

Hydro One Remote Communities:



An inspection of the area identified as Hydro One Distribution's service territory reveals that it includes extensive areas that likely do not have much distribution service. These areas include provincial parks, hunting reserves, crown lands, and lakes as well as privately owned land that has very few towns or roads. Several of the towns in the footprint of Hydro One's service territory are served by other distributors, including Hydro One Remote Communities. These areas are located chiefly in western Ontario but the Company also serves sparselypopulated areas of central and eastern Ontario.

PEG does not object to having some unserved areas included in a service territory inasmuch as this is also the case for many U.S. distributors. However, for this area measure to serve its purpose in cost benchmarking, the value used for the subject of benchmarking should at least be plausibly proportional in the amount of unserved area in the total or the results will be biased. The working papers for the 2018 benchmarking study done by Mr. Fenrick for THESL included service territory maps for sampled U.S. distributors. An examination of the maps suggested that only Southern Ontario was reasonably similar in this regard to what might be found for a typical distributor in the U.S. sample.

As an example, the above map of Hydro One shows the relative size of Western Ontario vs. Wisconsin (169,640 sq km). The Western Ontario region appears to be at least as large as the more rural area of Wisconsin north of the Highway connecting Madison and Milwaukee in the southern part of the state. An examination of the distribution of towns in Northern and Central Wisconsin reveals that despite its rural character, electrified population centers are quite common. There are many state and county highways connecting these areas. However, when one examines a similar sized area in Western Ontario a different situation is evident.

One way to judge population density is to examine the road network. For Ontario, (The Official Road Map of Ontario (gov.on.ca)) one can see that the rural areas of Southern Ontario have a relatively dense road network that connects many farms, cottages, and small towns. This seems to PEG to be comparable to what one might find in many rural areas of the U.S. By contrast, many areas of Western Ontario have very few roads. Many of these roads that access Northern Ontario have very little in the way of services for very long stretches where no population centers exist. In the opinion of PEG this situation is unusual for companies in the distribution sample. The area of Eastern Montana and the Western Dakotas seem to be comparable.

After concluding that the service territory of Hydro One was so atypical that it compromised the benchmarking results, PEG adopted the approach of using the transmission line miles as a proxy for the footprint of where loads may be located.

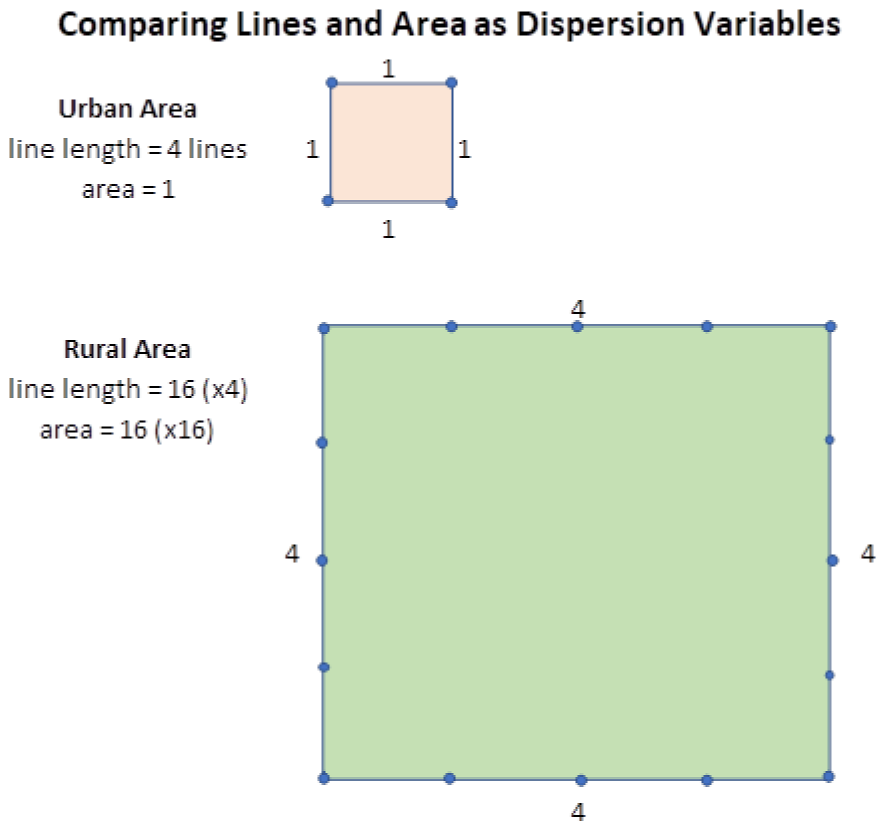
d) This is a complicated issue that lacks a clear answer. PEG acknowledges that customer dispersion is an important driver of distribution cost. Getting dispersion right is especially important in a benchmarking study of Hydro One Distribution because it faces unusually large dispersion. The cost model has a translog form that can make the score for Hydro One especially sensitive to the dispersion variable chosen.

Customer dispersion has several dimensions. One is that greater dispersion requires longer distribution lines to be constructed and maintained. Dispersion can also increase the distance between lines. For example, if service is only provided to towns, it is more costly if these are widely scattered rather than in close proximity. Of these two dimensions of dispersion, PEG believes that the length of lines is the more important cost driver. Thus, distribution line length is the most relevant single measure of customer dispersion for cost benchmarking. Unfortunately, while good distribution line data are readily available for Ontario distributors, they are not readily available for most investor-owned U.S. distributors. It is not clear whether area is preferable to transmission line length as a feasible alternative dispersion variable.

The area data that Mr. Fenrick compiled are a useful measure of the dispersion of power distribution customers which is readily available for U.S. investor-owned electric utilities. However, it is not ideal. To see why, consider the following figure in which the distribution system for a suburban city block is compared to the system serving an area of small farms that is surrounded by roads. It can be seen that the length of the lines serving one suburban block is four units. The area served is one square unit, and this is a reasonable estimate of the area actually served.[9] A distributor serving the rural area must have sixteen units of lines, which is four times the amount required for the suburban block. The area of the rural block is, in contrast, *16 times* the area of the suburban block. Moreover, service is actually provided only to the periphery of the rural block, where the houses and farm buildings are likely to be located. The area actually receiving service is roughly 6 times the area receiving service in the suburban block. Thus, estimates of the area that utilities are *licensed* to serve tend to be less accurate estimates of the area they *actually* serve to the extent that the utilities principally serve rural areas.

This analysis suggests that, whereas area is a useful measure of dispersion in the absence of line length data, and is doubtless positively correlated with line length, its use in benchmarking would tend to favor utilities that serve rural areas more than urban areas.

[9] Consideration of service on the other side of the street would not change the basic result detailed here.



PEG endeavored to develop an estimate of the area actually served by Hydro One Distribution. A sensible measure of this is the average area of Ontario utilities times the ratio of hydro One's distribution line km to the Ontario average. This calculation produced an estimate of 82,721 miles.

It is also noteworthy that, in PEG's distribution total cost research they found that the transmission line length variable had an estimated cost elasticity that was a little higher than that for the Clearspring area variable if the latter variable was used as an alternative. The t statistic on the transmission line length variable was a little lower but still indicative of high significance. In runs where both variables were included in the same model both of the parameter estimates had high statistical significance. Thus, area and transmission line length were found to be similarly important drivers of distribution total cost. It would be desirable to know whether transmission line length or area are a more important driver of distribution cost but this exercise is not possible using U.S.

data.

One disadvantage of transmission lines is that the footprints of the transmission and distribution systems sometimes differ. While this is actually true of Hydro One, it should not disadvantage the Company in a distribution cost benchmarking study since its transmission system is unusually large relative to its distribution system. Another disadvantage of transmission lines is that quite a few companies must be excluded from the econometric calculations. This is most commonly due to the fact that these companies don't provide transmission service. Many of these (e.g., Consumers Energy and Wisconsin Electric Power) serve forested rural areas of the northern U.S.

We conclude that, while customer dispersion is an important issue in an econometric cost benchmarking study for Hydro One Distribution, the ideal measure of dispersion is unavailable and we are forced to choose between two imperfect alternatives that produce considerably different scores.

Suppose now that despite the limitations of service territory area it is going to be used in an econometric distribution cost benchmarking study for Hydro One. It is unreasonable to pair an estimate of the area Hydro One actually serves with the areas that have been estimated by Clearspring using Platt's maps. PEG's review of the Platt's maps suggested that roughly half of the utilities had maps that were decent or good representations of the area actually served but half of the utilities did not.[10] On this basis, an improved estimate of Hydro One's service territory area that is consistent with U.S. data would be 0.50 x 651,974 + 0.50 x 82,721 = 325,987 + 41,361 = 367,348 sq. km.

When this value for area is used in the Clearspring distribution total cost model, Hydro One receives a 13.2% average score from 2017 to 2019 and a 17.4% average score from 2023-2027. This topic will merit revisitation in future Hydro

[10] The variance in accuracy was chiefly a matter of the extent to which the service territory consisted chiefly of towns and cities.

One CIR proceedings.

e) Yes. Distribution line miles is one of the most desirable measures of customer dispersion for a distribution cost study. It is preferable to area as well as to transmission line miles.

f) This statement cannot be confirmed. Giving Hydro One "credit" is a matter of the estimated cost impact of a given business condition variable. Because transmission line length and area have different cost impacts, equivalency does not hold.

   Our discussion in response to part d) suggests that 94,091 sq. km. might be interpreted as an estimate of the area that Hydro One Distribution actually serves as distinct from the area it is licensed to serve. While the area may still seem small, it is to be remembered that there would be roughly 1.3 million customers in this hypothetical area. This estimate is actually higher than the 82,721 estimate that is based solely on distribution line length because Hydro One Transmission serves the entire province and not just the area that Hydro One Distribution serves.

   It should also be noted that the reasonableness of the transmission line length variable depends on the number of customers served. Amongst the distributors in PEG's sample, Hydro One's 64.7 customers per transmission line km is well below that of Idaho Power (73.5), Empire District Electric (76.3), Kansas Gas and Electric (78.2), or Monongahela Power (108.5). All of these utilities serve extensive rural areas but some also serve cities of moderate to large size (e.g. Boise and Wichita). In contrast, Hydro One's 2.0 customers per km of estimated area is comparable to that for only one sampled U.S. distributor, Montana Dakota Utilities (2.2). The company with the next lowest score, Idaho Power, has three times the density of Hydro One at 6.4 customers / sq km.

g) Please see the response to part f of this question.

h) PEG is unable to confirm an exact figure, but the value provided seems plausible.

i) PEG acknowledges that Hydro One and other Ontario distributors serve areas outside of southern Ontario.

j) This statement is confirmed for the CIR period.

M-HYDRO ONE-22

Reference: Exhibit M, Pages 49 – 54

Preamble: PEG provides its distribution total cost model.

Interrogatories:

a) Please explain why PEG does not include the standard deviation of elevation variable in its distribution cost models as it did include the variable in its Hydro Ottawa benchmark cost models?

b) Please explain why PEG added a new scope variable to its distribution cost models that examines the percent of distribution of transmission and distribution plant.

c) Did PEG include the percent of distribution of transmission and distribution variable in its research in the prior Hydro Ottawa, Toronto Hydro, or the last Hydro One Distribution applications?

d) Would the inclusion of this new scope variable have helped the scores of Hydro Ottawa or Toronto Hydro if PEG had included it in those applications since those utilities do not offer transmission services (all else being equal)?

e) Please confirm that the inclusion of this new variable harms Hydro One's distribution total cost benchmark score by approximately 7 percent (all else being equal). If PEG cannot confirm, please provide PEG's estimate of the impact and explanatory details including the model used to estimate the impact.

f) Is PEG's new scope variable for distribution (percent distribution plant in transmission and distribution plant) consistent with its scope variable in its transmission cost models which measures percent transmission plant in total utility plant net of general plant? Please explain.

g) Please explain why PEG includes the statistically insignificant first order variable of percent overhead distribution plant in its distribution total cost model (p-value = 0.262) when it states on p. 49, "In all three models, all of the parameter estimates for the first-order terms of the business condition variables were statistically significant and plausible as to sign and magnitude."

h) Please confirm that if PEG uses the exact same model explanatory variables and explanatory variable values in its distribution total cost model for Hydro One (with no other methodological changes made) that PEG used in its Hydro Ottawa distribution benchmarking research, the PEG total cost result improves by approximately 29% for Hydro One and is almost identical to Clearspring's distribution total cost results. If not confirmed, please provide an estimate of what PEG's result would have been for Hydro One's distribution total costs if PEG had used the same model it supported in the Hydro Ottawa proceeding, and provide explanatory details and model used to estimate this impact.

i) Please confirm there are no substation variables included in either Clearspring or PEG's distribution models.

Responses:

The following response was provided by PEG.

a) PEG did not include the elevation variable in their distributor cost models for several reasons. One is that elevation had a statistically significant parameter estimate in PEG's power distribution *capital* cost research but not in their *OM&A* cost research. This outcome did not have intuitive appeal and raised the concern that elevation is correlated with other excluded cost drivers. Another concern was that the model, which includes second order terms for three scale variables, has quite a few variables relative to the sample size.

b) PEG is increasingly concerned about the use of scope variables in their econometric cost models. Economies of scope may in principle be achieved when utilities are engaged in generation and transmission as well as distribution. These economies may result from superior coordination opportunities and from spreading costs of the central office over a wider range of services. PEG, like Clearspring, has in several studies used scope economy variables such as the share of transmission plant in the gross value of generation, transmission, and distribution plant. A notable problem with such a variable is that the gross value of transmission (or distribution) plant tends to be correlated with transmission (or distribution) capital cost, and capital cost is a large component of total cost. The parameter estimates for such variables are surprisingly high and their inclusion in a benchmarking model tends to materially affect the estimates of other parameters and Hydro One's benchmarking scores.

In PEG's distribution benchmarking models they used the share of distribution in the gross value of T&D plant for two reasons. First, coordination between transmission and distribution seems much more likely to affect distribution cost than coordination between distribution and generation. The matter of spreading central office costs over generation as well as transmission and distribution should be a fairly small issue. Secondly, the variable PEG chose may also address the possible presence of subtransmission lines on the distribution system. If a utility does have distribution lines with a subtransmission voltage, it will raise the share of distribution in the gross value of T&D plant.

c) No. This is another area in which PEG's methodological preferences are evolving. PEG notes, however, that including some scope variable in the distribution models is consistent with the inclusion of scope variables in the transmission models. Clearspring, in contrast, has a scope economy variable in its transmission total cost model (where Hydro One had a high value) but not in their distribution model.

d) PEG does not know what would have happened to the benchmarking scores of Toronto Hydro or Hydro Ottawa had this scope variable been added to PEG's benchmarking models in those proceedings. Intuition suggests that it might have improved their scores but those models were quite different. There is no assurance that this variable would have had a statistically significant parameter estimate.

e) PEG confirms that the exclusion of this variable from their total cost benchmarking model would produce a modest improvement in Hydro One's score. The share of distribution in the gross value of Hydro One's T&D plant is below the sample norm. One reason is that the Company provides transmission service to the entire province whereas it provides distribution service to only a portion of same. Most power carried by the Company's transmission system is not delivered to its distribution system.

f) No. Please see our response to part b) for the requested explanation.

g) The overhead variable was highly significant and plausibly-signed in PEG's OM&A and capital cost models. PEG has in several recent studies used a 75% significance test to exclude business condition variables from its cost benchmarking models and did not notice that the parameter estimate for the overheading variable fell just short of clearing this test in the final distribution total cost model.

h) The 29% figure is confirmed for the CIR period using the current analogous variables and OLS estimation. Despite arriving at the same figure as Clearspring, using the exact same variables and values is not feasible for three reasons:

   a. The data used in the Hydro Ottawa proceeding ends in 2017

   b. All of the values will change due to the updated meanscaling resulting from two additional years of data and some sample differences.

   c. The peak measure differs. In the Hydro Ottawa proceeding both PEG and Clearspring used 5-year ratcheted peak data.

   PEG does not agree that the results are "almost identical to Clearspring's." Certainly, the results are much closer. PEG notes that their model for Hydro Ottawa used a specification which corrected for level 1 autocorrelation in the data. PEG has confirmed that there is very strong evidence of level 1 autocorrelation in the data for this proceeding as well. Below PEG presents the yearly benchmarking results for Hydro One using the requested explanatory variables and similar values as the Hydro Ottawa proceeding from the current database for both OLS and AR(1)-corrected estimation methods.

[Actual - Predicted Cost]

Year	OLS Cost Benchmark Score	AR1-Corrected Cost Benchmark Score
2002	-12.73%	-12.52%
2003	-13.34%	-13.25%
2004	-18.29%	-18.20%
2005	-15.71%	-15.87%
2006	-11.33%	-11.12%
2007	-2.89%	-2.26%
2008	-4.27%	-3.14%
2009	0.68%	2.20%
2010	0.61%	2.58%
2011	2.48%	4.88%
2012	2.30%	5.37%
2013	6.34%	9.36%
2014	9.65%	12.36%
2015	6.29%	8.76%
2016	6.60%	9.59%
2017	5.15%	8.15%
2018	6.05%	8.48%
2019	6.19%	8.26%
2020	4.68%	6.67%
2021	2.00%	3.88%
2022	1.38%	3.16%
2023	5.29%	6.97%
2024	6.81%	8.38%
2025	8.77%	10.22%
2026	9.87%	11.22%
2027	11.06%	12.30%
Average 2017-2019	**5.80%**	**8.30%**
Average 2023-2027	**8.36%**	**9.82%**

i) This statement is confirmed.