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BY EMAIL AND RESS

July 21, 2022

Ms. Nancy Marconi
Registrar
Ontario Energy Board
Suite 2700, 2300 Yonge Street
P.O. Box 2319
Toronto, ON M4P 1E4

Dear Ms. Marconi,

EB-2021-0110 – Custom IR Application (2023-2027) for Hydro One Networks Inc. Transmission and Distribution – Clearspring and PEG Interrogatory Responses

Please find enclosed, pursuant to Procedural Order No. 5, interrogatory responses from Clearspring Energy Advisors (Clearspring) and Pacific Economics Group (PEG).

Hydro One is filing these responses on behalf of Clearspring and PEG. These have been submitted to the Ontario Energy Board's Regulatory Electronic Submission System.

Sincerely,

Kathleen Burke

Kathleen Burke

cc. EB-2021-0110 parties

JR – OEB STAFF INTERROGATORY – 398

Reference:

Joint Report, Page 3

Preamble:

On page 3 of the Joint Report, under Research Upgrades for Power Transmission Research / PEG, the third bullet on the list states:

- PEG agrees with Clearspring that the construction cost index variable value for the Company should reflect where its transmission lines actually are rather than its full licensed service territory.

OEB staff notes that "the Company" is not a defined term in the Joint Report.

Interrogatory:

a) Please confirm that "the Company" is referring specifically to Hydro One. In the alternative, please explain.

b) Please state whether or not Clearspring and PEG believe that the third bullet referenced above, which is that the construction cost variable should be determined based on where the lines are rather than on a utility's licensed service territory, should apply to any utility used in the analysis. Please explain your response(s).

c) Please confirm that both Clearspring and PEG believe that the construction cost index variable for each of the U.S. utilities in the Transmission sample satisfies this criterion. Please explain your response(s).

Joint Response:

a) **Clearspring**: This statement is confirmed.

PEG: This statement is confirmed.

b) **Clearspring**: For the U.S. sample, how the construction cost variable is defined (either using transmission line locations or distribution service territory) will have little impact on the variable value. The National Electrical Safety Code (NESC) loading zones for the U.S. cover large areas and many utilities are only covered by one NESC loading zone. For these utilities, this means the variable would be the same regardless of if licensed service territory or location of lines is used. In the case of a utility being in two or more NESC zones, the variable may go up or down slightly and randomly depending on the definition used. However, since most of the U.S. sampled utilities are significantly more dense in terms of transmission lines in their service territory, we would expect a far smaller change than seen for Hydro One. This change could either slightly increase or decrease the variable value for those transmitters.

In the distribution benchmarking research, Hydro One's distribution service territory variable is also treated differently than the rest of the sample due to the uniqueness of its licensed service territory and this same justification for different treatment is appropriate for the transmission construction cost variable. Whereas most of the U.S. sample has customers (and transmission lines) spread throughout most of the geographic areas of its licensed service territory, Hydro One has no customers (or transmission lines) in the upper half of northern Ontario. Just as both Clearspring and PEG agreed it was appropriate to reduce the licensed service territory variable value for Hydro One's distribution benchmarking, we both agreed it was appropriate not to have the unserved areas of northern Ontario influence the transmission construction cost variable.

PEG Response: PEG acknowledges that it would be desirable to base the construction cost index values of US utilities on each company's actual transmission footprint.

c) **Clearspring**: Please see the response to part b.

PEG Response: PEG does not believe that the construction cost index values for US utilities in the sample were based on each company's transmission footprint. However, values based on the distribution footprint are still valuable. The transmission and distribution footprints of many US utilities are similar. Even where they or not, the score would often be similar if calculated correctly. The inaccuracies should be random. Hydro One is clearly one utility that has notably different transmission and distribution footprints. Transmission assets are concentrated in the southernmost part of the province.

JR – OEB STAFF INTERROGATORY – 399

Reference:

Joint Report, Page 3

Preamble:

On page 3 of the Joint Report, under Research Upgrades for Power Transmission Research / PEG, the fifth bullet on the list states:

- For its transmission total cost and capital cost models, PEG has replaced its plant-based scope variable with a more defensible scope variable based on operation and maintenance ("O&M") expenses.

Interrogatory:

a) Please provide more detail on the construction of this "economies of scope" variable based on O&M expenses. For example, how is this constructed for the U.S. utilities, and is it based on data from FERC Form 1 data or other data sources?

b) Please provide more explanation on why PEG considers this measure more defensible compared to the "economies of scope" variable Clearspring used in its initial evidence.[1]

c) Please explain how PEG constructed this O&M expenses-based "economies of scope" variable for Hydro One.

PEG Response:

a) The economies of scope variable is based on FERC Form 1 data for US utilities. It is the ratio net transmission O&M expenses to net production, transmission, and distribution O&M expenses. Net transmission O&M includes all maintenance expenses and the following categories of operation expenses: supervisory and engineering, station, overhead line, underground line and rents. This measure excludes expenses in the accounts transmission by others, miscellaneous, and the several accounts formerly classified as dispatching. The denominator is the sum of net transmission O&M expenses, total distribution O&M expenses, and production O&M expenses less those in the steam, nuclear, and other power generation fuel accounts.

[1] Exhibit 4 / Tab 1 / Schedule 1 / Attachment 1 / p. 21, section 3.1.3. Clearspring uses a measure of "percentage of transmission plant in total electric plant" to measure electricity transmission economies of scope.

Witness: Pacific Economics Group

b) The chief benefit of this variable is that it is less endogenous than a variable based on plant value. Endogeneity of explanatory variables is a key assumption of econometric analysis. A company whose plant has a high value will tend to have higher capital cost and total cost. These considerations matter all the more because power transmission is an unusually capital-intensive business. A second benefit of this variable is that it has stronger statistical support than the plant-based variables used in the original Clearspring and PEG total cost models.

c) The value for HON was constructed using data available in the Clearspring working papers. The value for production O&M cost was zero, the transmission O&M cost was reduced by 12% to remove dispatch and miscellaneous O&M expenses. The value did not include any customer care expenses related to transmission or any general O&M allocated to transmission operations.

JR – OEB STAFF INTERROGATORY – 400

Reference:

Joint Report, Page 4
Exhibit A-4-1, Attachment 1
Exhibit M

Preamble:

In each of the original reports (i.e., Exhibit A / Tab 4 / Schedule 1 / Attachment 1 for Clearspring, and Exhibit M for PEG), Clearspring and PEG provided summary tables of regression model outputs and benchmarking scores for Hydro One, and figures of Hydro One's estimated cost benchmarking score over the regression and plan period and of Hydro One's total cost benchmarking ranking relative to the sample of utilities used in each analysis. The following table identifies the relevant tables and figures in each consultant's evidence:

Clearspring (Exhibit A / Tab 4 / Schedule 1 / Attachment 1)				
	Regression Output	**Hydro One Cost Benchmarking Score**	**Hydro One Cost Benchmarking Score (Chart)**	**Hydro One Cost Benchmarking Ranking in Sample (Chart)**
Transmission	Table 2	Table 3	Figure 7	Figure 8
Distribution	Table 6	Table 7	Figure 10	Figure 11
PEG (Exhibit M)				
Transmission	Table 1	Table 5	Figure 1	
Distribution	Table 10	Table 13	Figure 4	

On page 4 of the Joint Report, Clearspring and PEG provide a short summary under a section titled "Revised Benchmarking and Productivity Results for Power Transmission Research".

Interrogatory:

a) For each of the updated models that Clearspring and PEG have estimated based on the updates with respect to time period, sample inclusions and exclusions, and variable definition and constructions, as summarized on page 4 of the Joint Report, please provide updated tables and charts (figures) corresponding to the above-referenced tables and figures in each consultant's original evidence.

b) In Exhibit M, PEG also provided tables on cost benchmarking of Transmission and Distribution costs separately for capital and for OM&A.

i. Were these supplementary analyses considered by Clearspring and PEG in the discussions leading to the preparation of the Joint Report? If considered, please explain why these were not discussed in the Joint Report. If not considered, please provide an explanation for the exclusion from the Joint Report.

ii. If available, please provide updated tables and figures corresponding to the capital and OM&A cost benchmarking models and scores as contained in Exhibit M, but corresponding the updated analyses summarized under "Revised Benchmarking and Productivity Results for Power Transmission Research" on page 4 of the Joint Report.

Response:

a) **Clearspring Response:** Here are the updated figures and tables.

1 **Table 1 Total Cost Model Estimates (Transmission)**

Variable	Coefficient	Standard Error	T-Statistic	P-Value
Constant	9.3777	0.0713	131.4460	0.0000
KM of Transmission Lines (KM)	0.4579	0.0083	55.2048	0.0000
Peak Demand (D)	0.3721	0.0078	47.6074	0.0000
KM*KM	-0.0539	0.0134	-4.0348	0.0001
D*D	-0.0608	0.0230	-2.6444	0.0083
KM*D	0.2699	0.0230	11.7272	0.0000
# of Subs	0.1805	0.0069	26.0266	0.0000
Average Line Voltage	0.4864	0.0136	35.8849	0.0000
% Overhead	-2.2657	0.0530	-42.7508	0.0000
Trend	0.0153	0.0020	7.4831	0.0000
Construction Standards	0.4767	0.0133	35.9549	0.0000
Forestation	0.0233	0.0022	10.5172	0.0000
OM&A Scope Variable	0.1909	0.0104	18.3169	0.0000
ISO	0.1489	0.0095	15.6054	0.0000

Table 2 2003-2027 Transmission Total Cost Benchmark Score for Hydro One

Year	% Difference from Total Cost Benchmark
2004	-40.5%
2005	-44.1%
2006	-45.1%
2007	-43.3%
2008	-46.9%
2009	-44.1%
2010	-44.1%
2011	-43.0%
2012	-39.0%
2013	-41.4%
2014	-40.4%
2015	-38.9%
2016	-38.4%
2017	-39.4%
2018	-36.6%
2019	-36.5%
2020	-37.4%
2018-2020 average score	**-36.8%**
2021	-38.0%
2022	-37.1%
2023	-33.9%
2024	-33.0%
2025	-31.0%
2026	-30.7%
2027	-29.7%
2023-2027 average score	**-31.6%**

Figure 1 Hydro One Transmission Total Cost Actual vs. Benchmark

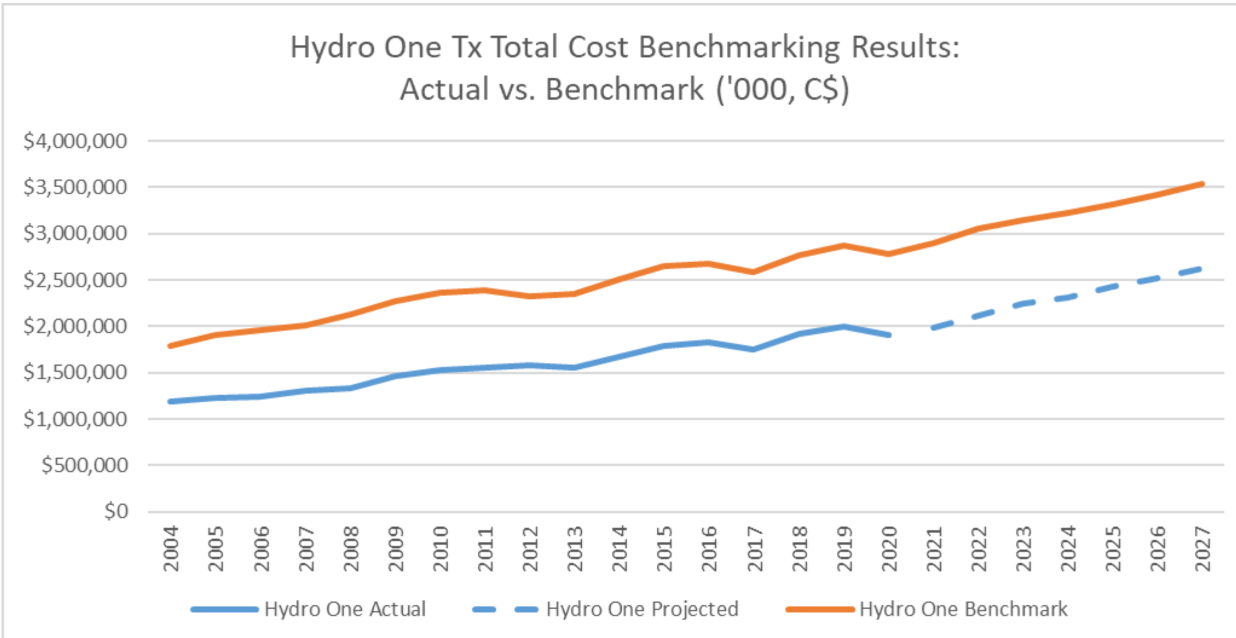
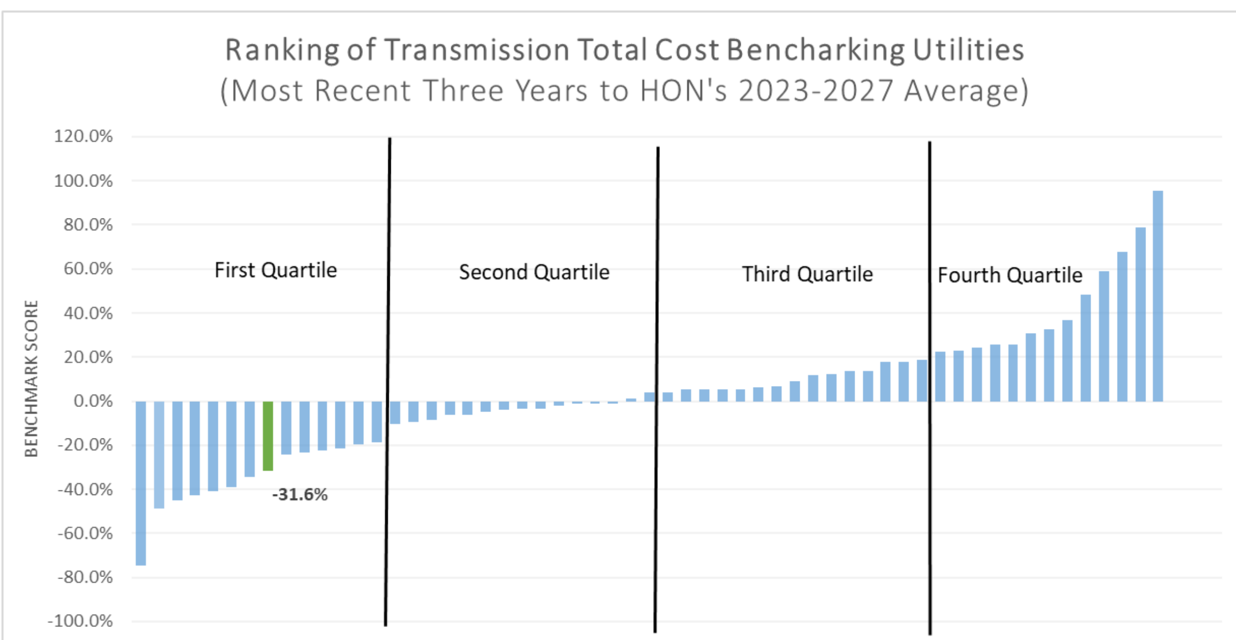


Figure 2 Ranking of Utilities by Transmission Total Cost Scores



1 **Table 3 Total Cost Model Estimates (Distribution)**

Variable	Coefficient	Standard Error	T-Statistic	P-Value
Constant	13.1612	0.0190	691.3708	0.0000
Customers (N)	0.5491	0.0102	53.5785	0.0000
Peak Demand (D)	0.4225	0.0115	36.7914	0.0000
Area (A)	0.0599	0.0019	31.9206	0.0000
N*N	0.8665	0.0482	17.9731	0.0000
D*D	1.1235	0.0507	22.1391	0.0000
A*A	0.0315	0.0028	11.4102	0.0000
N*D	-1.9558	0.0992	-19.7185	0.0000
N*A	0.1206	0.0126	9.5788	0.0000
D*A	-0.1368	0.0130	-10.5605	0.0000
% Electric	0.1638	0.0115	14.2691	0.0000
Standard Deviation of Elevation	0.0187	0.0022	8.4347	0.0000
% OH*% Forest	0.0460	0.0021	22.0489	0.0000
% Congested Urban	15.9850	0.7064	22.6289	0.0000
% AMI	0.0680	0.0082	8.3264	0.0000
Dx Work (% Tx Lines Above 50 kV)	0.1393	0.0135	10.2937	0.0000
Trend	-0.0048	0.0009	-5.5005	0.0000
OM&A Scope Variable	0.0815	0.0046	17.6959	0.0000

Table 4 2006-2027 Distribution Total Cost Benchmark Score for Hydro One

Year	% Difference from Total Cost Benchmark
2005	-24.0%
2006	-18.6%
2007	-9.9%
2008	-10.1%
2009	-5.0%
2010	-4.5%
2011	-2.2%
2012	-0.9%
2013	4.1%
2014	7.6%
2015	4.8%
2016	7.5%
2017	7.2%
2018	7.6%
2019	7.6%
2020	6.7%
2018-2020 average score	**7.3%**
2021	6.5%
2022	3.2%
2023	9.1%
2024	11.2%
2025	13.7%
2026	15.0%
2027	16.5%
2023-2027 average score	**13.1%**

Figure 3 Hydro One Distribution Total Cost: Actual vs. Benchmark

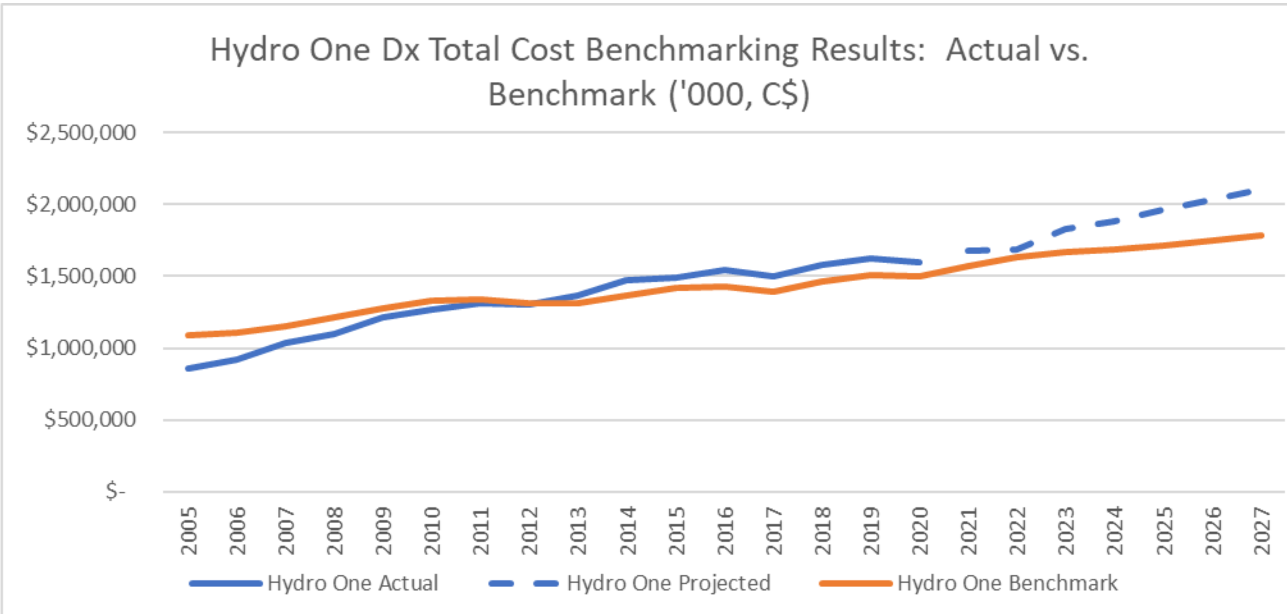
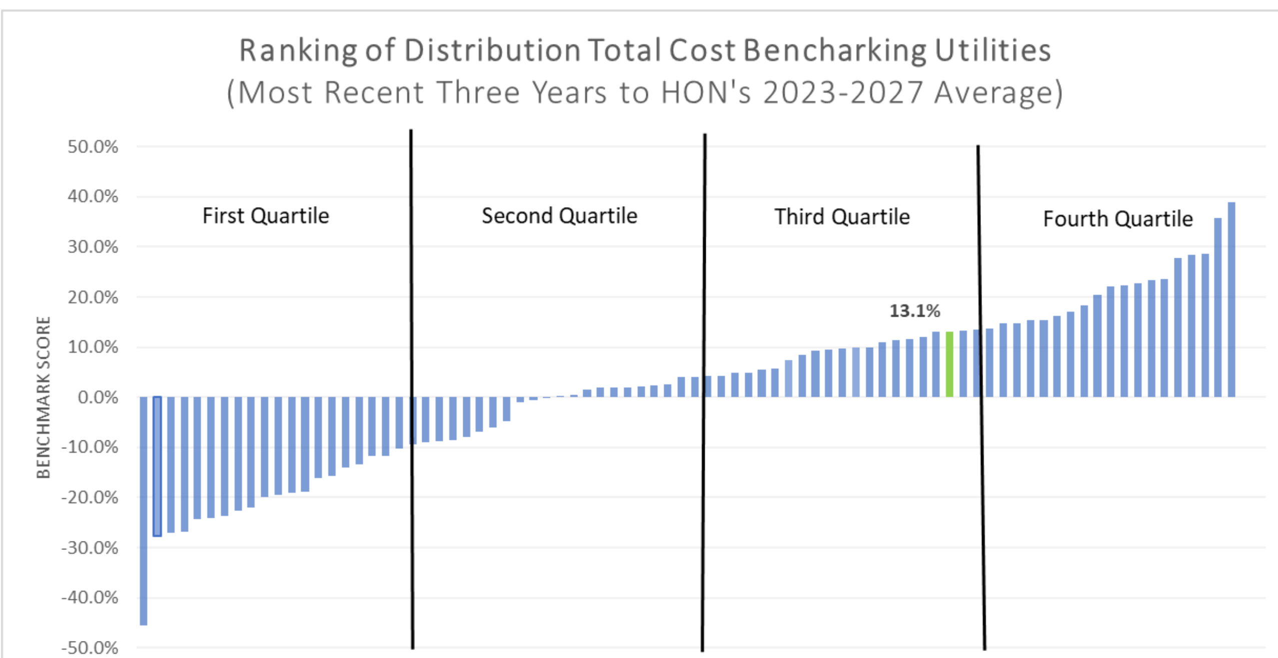


Figure 4 Ranking of Utilities by Distribution Total Cost Scores



a) **PEG Response:** Here are the requested tables and figures.

Table 1 (revised)

PEG's Featured Econometric Model of Transmission Total Cost

VARIABLE KEY

YL =	Kilometers of Transmission Line
D =	Ratcheted Max Transmission Peak
PCTOTXG =	Net TX O&M share of Net TX + DX + Generation O&M
MVA =	MVA per Substation
SUBKM =	Substation per KM of Transmission Line
PCTOH=	Percentage Overhead Lines
CS =	Construction Standards Index
VOLT =	Average Voltage of Transmission Lines
FOR =	Forestation of Service Territory
Trend =	Time trend

EXPLANATORY VARIABLE	PARAMETER ESTIMATE	T-STATISTIC	P-VALUE
YL	0.539	24.500	0.000
D	0.460	22.680	0.000
YL*YL	-0.043	-1.150	0.268
D*D	0.045	1.860	0.083
D*YL	0.058	1.780	0.095
PCTOTXG	0.240	25.930	0.000
MVA	0.170	7.520	0.000
SUBKM	0.162	6.940	0.000
PCTOH	-1.516	-7.800	0.000
CS	0.278	13.260	0.000
VOLT	0.288	21.370	0.000
FOR	0.090	7.180	0.000
Trend	0.011	4.030	0.001
Constant	12.075	475.720	0.000

Adjusted R^2	0.927
Sample Period	2004-2019
Number of Observations	887

Table 5 (revised)

Transmission Total Cost Performance of Hydro One Using PEG's Alternative Econometric Model

[Actual - Predicted Cost]

Year	Cost Benchmark Score
2004	-21.49%
2005	-26.68%
2006	-28.10%
2007	-25.92%
2008	-29.78%
2009	-27.05%
2010	-26.62%
2011	-25.32%
2012	-22.10%
2013	-21.23%
2014	-21.74%
2015	-20.43%
2016	-20.70%
2017	-21.49%
2018	-19.13%
2019	-18.17%
2020	-16.84%
2021	-18.41%
2022	-20.00%
2023	-16.83%
2024	-15.17%
2025	-13.85%
2026	-12.68%
2027	-11.74%
Average 2017-2019	**-19.60%**
Average 2023-2027	**-14.05%**

Figure 1 (revised)

Hydro One's Total Transmission Cost Benchmarking Scores Using PEG's Alternative Econometric Model

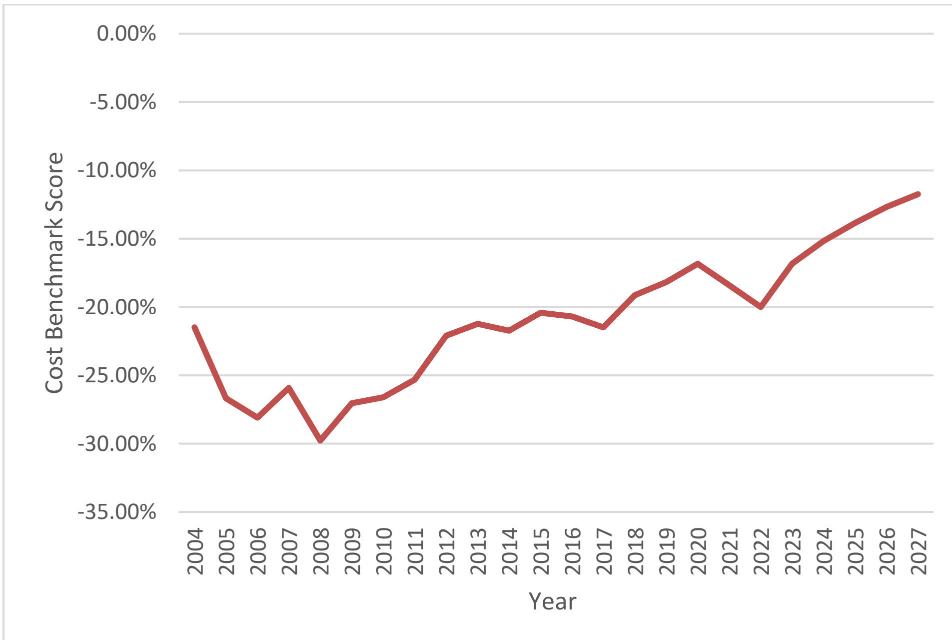


Table 10 (revised)

PEG's Featured Econometric Model of Distribution Total Cost

VARIABLE KEY

A =	Area of Service Territory
N =	Number of Customers
D =	Ratcheted Max Distribution Peak
PELEC =	Percent Electric Customers
OHFOR =	Percent Overhead Distribution Plant times Forestation of Service Territory
PCTODXG =	Net DX O&M share of Net TX + DX + Generation O&M
AMI =	Percent AMI
PTCU =	Percent Service Territory Congested Urban
ELEV =	Standard Deviation of Elevation of Service Territory
Trend =	Time trend

EXPLANATORY VARIABLE	PARAMETER ESTIMATE	T-STATISTIC	P-VALUE
A	0.041	5.660	0.000
N	0.527	32.910	0.000
D	0.459	28.950	0.000
A*A	0.023	3.860	0.001
N*N	0.952	13.400	0.000
D*D	1.127	13.870	0.000
Y*N	0.020	2.800	0.012
A*D	-0.022	-3.350	0.004
N*D	-1.017	-13.210	0.000
PELEC	0.119	5.680	0.000
OHFOR	0.034	22.190	0.000
PCTODXG	0.069	8.700	0.000
AMI	0.014	9.660	0.000
PTCU	0.011	16.490	0.000
ELEV	0.024	9.000	0.000
Trend	-0.004	-4.010	0.001
Constant	13.120	1319.880	0.000

Adjusted R^2	0.974
Sample Period	2002-2019
Number of Observations	1,383

Table 13 (revised)

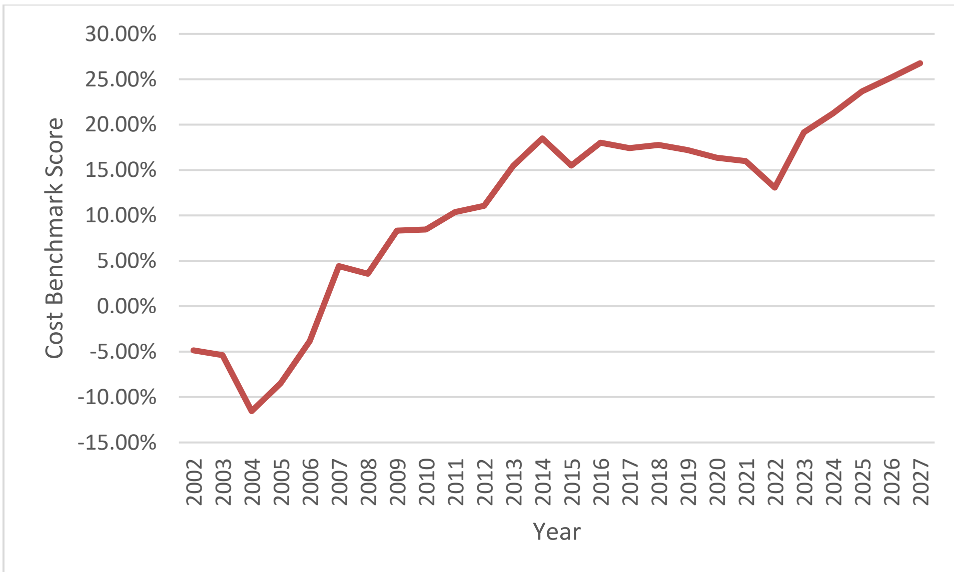
Year-by-Year Total Distribution Cost Benchmarking Results

[Actual - Predicted Cost]

Year	Cost Benchmark Score
2002	-4.86%
2003	-5.39%
2004	-11.55%
2005	-8.49%
2006	-3.83%
2007	4.43%
2008	3.59%
2009	8.33%
2010	8.45%
2011	10.38%
2012	11.05%
2013	15.47%
2014	18.50%
2015	15.50%
2016	18.02%
2017	17.41%
2018	17.78%
2019	17.20%
2020	16.36%
2021	15.99%
2022	13.08%
2023	19.17%
2024	21.25%
2025	23.66%
2026	25.18%
2027	26.77%
Average 2017-2019	**17.46%**
Average 2023-2027	**23.21%**

Figure 4 (revised)

Hydro One's Total Distribution Cost Benchmarking Scores



b) **<u>Clearspring Part i:</u>** These supplemental analyses were not considered in the discussions to any significant extent. The discussions were focused on the issues and points of disagreement raised in the Clearspring and PEG initial reports (which we thought was the intended scope of the discussions). PEG updated its supplemental analysis, consistent with the changes made to the total cost benchmarking results. Clearspring did not provide supplementary capital/OM&A benchmarking analyses in its original report.

<u>PEG Response Part i</u>: PEG considered these supplemental analyses but did not discuss them with Clearspring as Clearspring sought to limit the scope of the discussions. Here are the corresponding results for OM&A and capital costs.

<u>PEG Response Part ii</u>: Here are the requested tables and figures. Please note the following.

- Hydro One's deteriorating total transmission and distribution cost benchmarking scores are due to capital cost and not OM&A expenses. The Company's transmission OM&A cost benchmarking scores have trended downward since 2007, while its distribution OM&A benchmarking scores have trended downward since 2014. Transmission capital cost is still below the norm but distribution capital cost is well above the norm.

Table 2 (revised)

PEG's Featured Econometric Model of Transmission Capital Cost

VARIABLE KEY

YL =	Kilometers of Transmission Line
D =	Ratcheted Max Transmission Peak
PCTOTXG =	Net TX O&M share of Net TX + DX + Generation O&M
MVA =	MVA per Substation
SUBKM =	Substation per KM of Transmission Line
PCTOH=	Percentage Overhead Lines
CS =	Construction Standards Index
VOLT =	Average Voltage of Transmission Lines
FOR =	Forestation of Service Territory
Trend =	Time trend

EXPLANATORY VARIABLE	PARAMETER ESTIMATE	T-STATISTIC	P-VALUE
YL	0.569	14.790	0.000
D	0.445	13.050	0.000
YL*YL	-0.114	-3.510	0.003
D*D	-0.012	-0.880	0.391
D*YL	0.121	5.430	0.000
PCTOTXG	0.213	11.000	0.000
MVA	0.188	4.720	0.000
SUBKM	0.177	5.320	0.000
PCTOH	-1.594	-11.820	0.000
CS	0.287	10.980	0.000
VOLT	0.309	29.010	0.000
FOR	0.086	6.940	0.000
Trend	0.014	4.410	0.001
Constant	9.887	440.040	0.000

Adjusted R^2	0.909
Sample Period	2004-2019
Number of Observations	899

Table 6 (revised)

Transmission Capital Cost Performance of Hydro One Using PEG's Alternative Econometric Model

[Actual - Predicted Cost]

Year	Cost Benchmark Score
2004	-19.99%
2005	-23.86%
2006	-27.09%
2007	-27.48%
2008	-28.60%
2009	-27.67%
2010	-25.31%
2011	-23.91%
2012	-20.75%
2013	-20.44%
2014	-18.93%
2015	-19.57%
2016	-18.93%
2017	-19.00%
2018	-17.55%
2019	-15.01%
2020	-15.65%
2021	-14.90%
2022	-15.06%
2023	-13.33%
2024	-11.59%
2025	-10.18%
2026	-8.95%
2027	-7.99%
Average 2017-2019	**-17.19%**
Average 2023-2027	**-10.41%**

Figure 2 (revised)

Hydro One's Transmission Capital Cost Benchmarking Scores Using PEG's Alternative Econometric Model

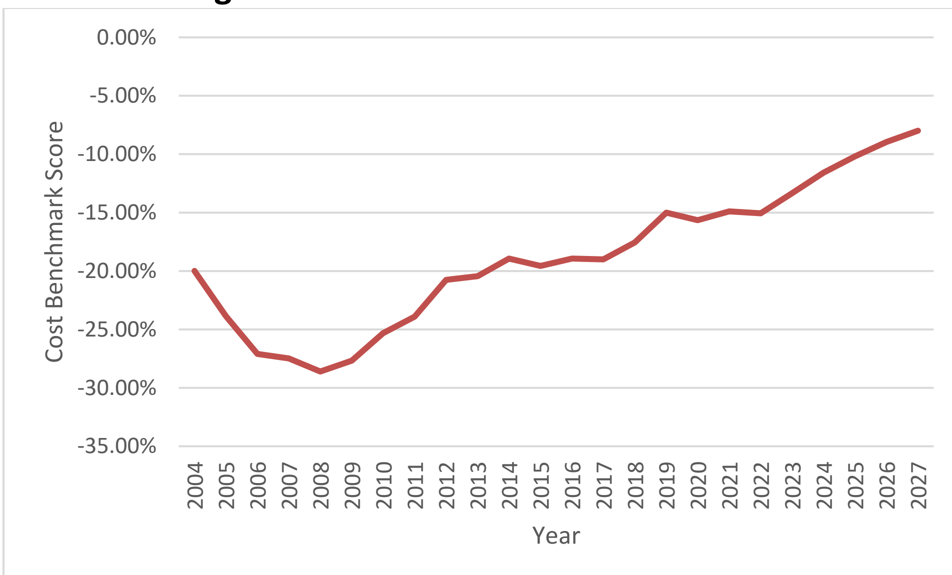


Table 3 (revised)

PEG's Featured Econometric Model of Transmission OM&A Expenses

VARIABLE KEY

YL =	Kilometers of Transmission Line
D =	Ratcheted Max Transmission Peak
PCTPTX =	Percent Transmission Plant of Total Plant net General Plant
MVA =	MVA per Substation
SUBKM =	Substation per KM of Transmission Line
PCTOH=	Percentage Overhead Lines
FOR =	Forestation of Service Territory
Trend =	Time trend

EXPLANATORY VARIABLE	PARAMETER ESTIMATE	T-STATISTIC	P-VALUE
YL	0.267	4.170	0.001
D	0.571	18.470	0.000
YL*YL	0.351	11.850	0.000
D*D	0.303	15.740	0.000
D*YL	-0.349	-10.810	0.000
PCTPTX	0.434	20.110	0.000
MVA	0.163	10.220	0.000
PCTOH	-0.834	-2.360	0.032
FOR	0.153	3.860	0.002
Trend	0.007	2.080	0.055
Constant	9.993	204.820	0.000

Adjusted R^2	0.782
Sample Period	2004-2019
Number of Observations	885

Table 7 (revised)

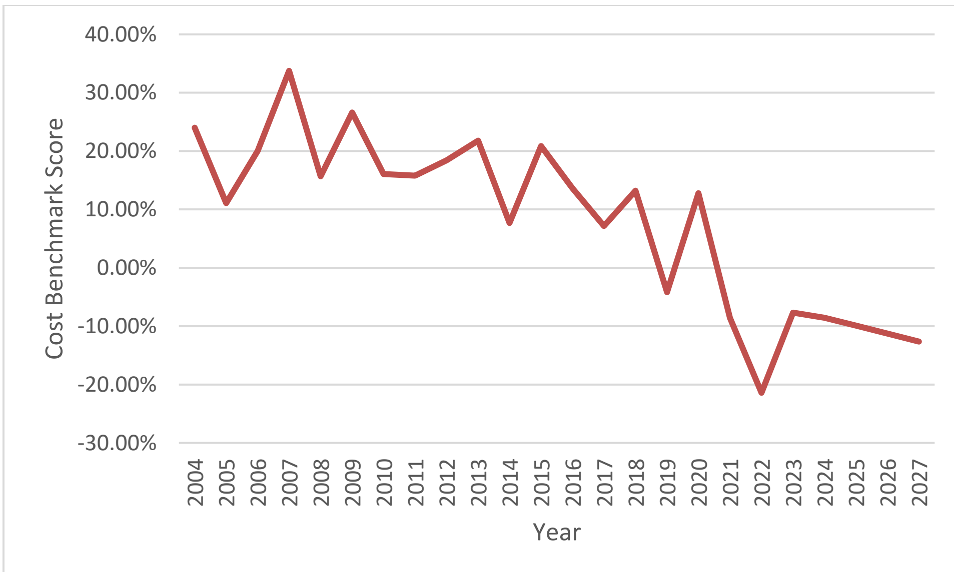
Transmission OM&A Cost Performance of Hydro One Using PEG's Alternative Econometric Model

[Actual - Predicted Cost]

Year	Cost Benchmark Score
2004	24.00%
2005	11.07%
2006	20.03%
2007	33.75%
2008	15.69%
2009	26.61%
2010	16.05%
2011	15.79%
2012	18.43%
2013	21.78%
2014	7.69%
2015	20.86%
2016	13.59%
2017	7.17%
2018	13.21%
2019	-4.18%
2020	12.77%
2021	-8.59%
2022	-21.41%
2023	-7.68%
2024	-8.56%
2025	-9.89%
2026	-11.27%
2027	-12.65%
Average 2017-2019	**5.40%**
Average 2023-2027	**-10.01%**

Figure 3 (revised)

Hydro One's Transmission OM&A Cost Benchmarking Scores Using PEG's Alternative Econometric Model



1 **Table 11 (revised)**

PEG's Featured Econometric Model of Distribution Capital Cost

VARIABLE KEY

A = Area of Service Territory
N = Number of Customers
D = Ratcheted Max Distribution Peak
PELEC = Percent Electric Customers
PCTPOH= Percent Overhead Lines
PCTODXG = Net DX O&M share of Net TX + DX + Generation O&M
AMI = Percent AMI
PTCU = Percent Service Territory Congested Urban
ELEV = Standard Deviation of Elevation of Service Territory
Trend = Time trend

EXPLANATORY VARIABLE	PARAMETER ESTIMATE	T-STATISTIC	P-VALUE
A	0.058	18.080	0.000
N	0.438	38.580	0.000
D	0.559	55.910	0.000
A*A	0.025	4.600	0.000
N*N	0.416	4.490	0.000
D*D	0.594	5.560	0.000
A*N	0.016	3.130	0.006
A*D	-0.012	-2.200	0.042
N*D	-0.494	-4.940	0.000
PELEC	0.148	6.420	0.000
PCTOH	-0.240	-5.690	0.000
PCTODXG	0.043	4.700	0.000
AMI	0.015	15.110	0.000
PTCU	0.011	7.250	0.000
ELEV	0.013	9.980	0.000
Trend	-0.004	15.110	0.000
Constant	10.660	-6.050	0.000

Adjusted R^2	0.971
Sample Period	2002-2019
Number of Observations	1,383

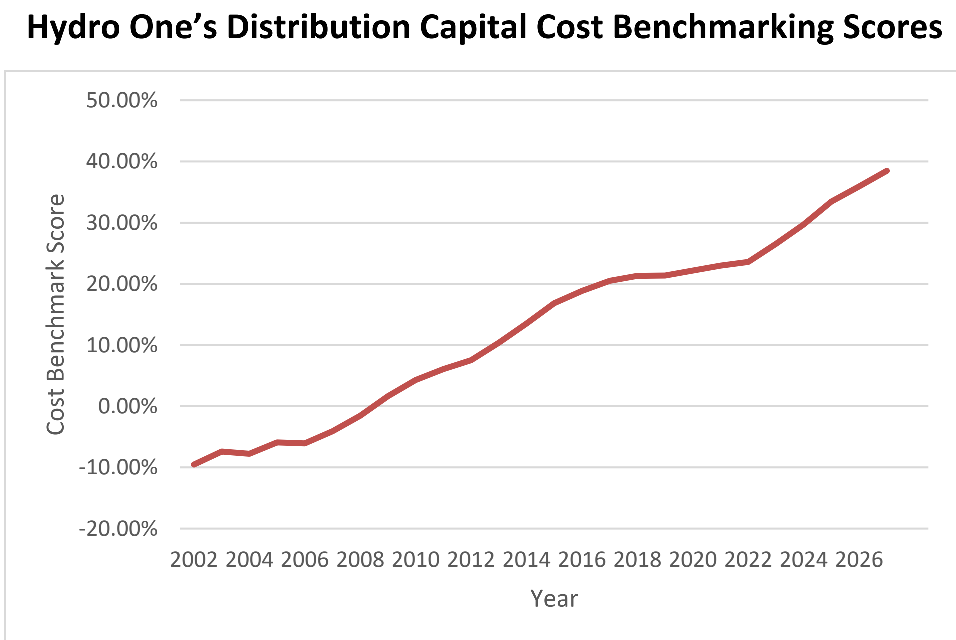
Table 14 (revised)

Year-by-Year Distribution Capital Cost Benchmarking Results

[Actual - Predicted Cost]

Year	Cost Benchmark Score
2002	-9.54%
2003	-7.41%
2004	-7.78%
2005	-5.91%
2006	-6.08%
2007	-4.08%
2008	-1.55%
2009	1.65%
2010	4.29%
2011	6.05%
2012	7.53%
2013	10.39%
2014	13.52%
2015	16.83%
2016	18.84%
2017	20.50%
2018	21.32%
2019	21.36%
2020	22.16%
2021	22.97%
2022	23.58%
2023	26.54%
2024	29.71%
2025	33.45%
2026	35.92%
2027	38.47%
Average 2017-2019	**21.06%**
Average 2023-2027	**32.82%**

Figure 5 (revised)



1 **Table 12 (revised)**

2 **PEG's Featured Econometric Model of Distribution OM&A Expenses**

VARIABLE KEY

A =	Area of Service Territory
N =	Number of Customers
D =	Ratcheted Max Distribution Peak
PCTOH=	Percentage Overhead Distribution Plant
OHFOR =	Percent Overhead Distribution Plant times Forestation of Service Territory
AMI =	Percent AMI
PTCU =	Percent Service Territory Congested Urban
PCTPDX =	Percent Distribution Plant of Total Plant net General Plant
ELEV =	Standard Deviation of Elevation of Service Territory
Trend =	Time trend

EXPLANATORY VARIABLE	PARAMETER ESTIMATE	T-STATISTIC	P-VALUE
A	-0.023	-0.990	0.336
N	0.844	16.240	0.000
D	0.175	4.110	0.001
A*A	0.038	5.530	0.000
N*N	2.211	16.100	0.000
D*D	2.174	15.320	0.000
A*N	0.002	0.090	0.926
A*D	-0.035	-1.420	0.174
N*D	-2.136	-15.420	0.000
PCTOH	0.840	9.870	0.000
PCTOH*PFOR	0.040	5.920	0.000
AMI	0.016	5.330	0.000
PTCU	0.007	6.670	0.000
PCTPDX	0.065	2.890	0.010
ELEV	0.047	3.930	0.001
Trend	-0.005	-2.910	0.010
Constant	11.897	722.660	0.000

Adjusted R^2	0.910
Sample Period	2002-2019
Number of Observations	1,383

Table 15 (revised)

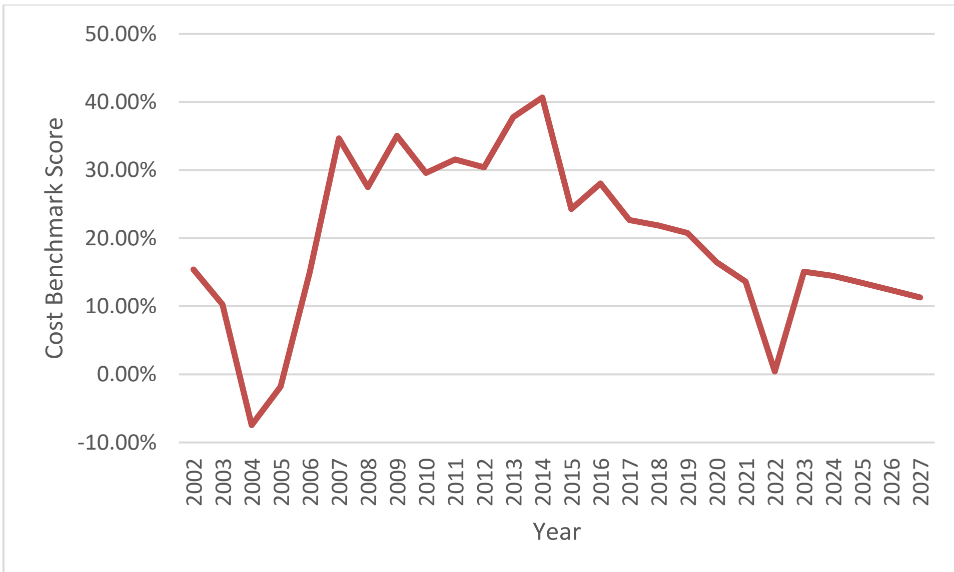
Year-by-Year Distribution OM&A Cost Benchmarking Results

[Actual - Predicted Cost]

Year	Cost Benchmark Score
2002	15.41%
2003	10.25%
2004	-7.46%
2005	-1.80%
2006	15.01%
2007	34.66%
2008	27.49%
2009	35.04%
2010	29.59%
2011	31.55%
2012	30.41%
2013	37.77%
2014	40.66%
2015	24.27%
2016	28.04%
2017	22.65%
2018	21.87%
2019	20.76%
2020	16.47%
2021	13.62%
2022	0.42%
2023	15.09%
2024	14.46%
2025	13.44%
2026	12.37%
2027	11.31%
Average 2017-2019	**21.76%**
Average 2023-2027	**13.33%**

Figure 6 (revised)

Hydro One's Distribution OM&A Cost Benchmarking Scores



JR – OEB STAFF INTERROGATORY – 401

Reference:

Joint Report, Page 8-9

Preamble:

As documented in the Joint Report, a key area of disagreement between Clearspring and PEG is with respect to the service area size of Hydro One. PEG documents its position on page 8, and Clearspring documents its position at the bottom of page 8 and continuing on page 9.

Interrogatory:

a) In Clearspring's discussion, there is reference to 20%, 40%, 60% being used to describe suburban versus rural utilities. Please indicate what the 20%, 40% and 60% are fractions of (e.g., geographical areas, number of customers, location of circuit kilometres of line, etc.)

b) On page 8 of the Joint Report, Clearspring states that:

> *We would expect Hydro One to have the lowest customer per sq. km in the sample since most of the cities and towns near its service territory are being served by other LDCs and Hydro One serving large portions of northern Ontario. The rest of the utilities in the sample do not have most of the cities and towns carved out of their service territory like Hydro One has.*

i. What is the basis for Clearspring's statement that "most of the cities and towns near its service territory are being served by other LDCs", in consideration that, since restructuring on April 1, 1999, Hydro One has acquired over 90 former municipal electrical utilities (MEUs) and LDCs serving villages, towns and cities throughout Ontario? Logically, it is tautological that "cities and towns near its service territory are being served by other LDCs", but why does Clearspring ignore the large number of electricity distribution systems of cities and towns that Hydro One has acquired since 1999 and now serves as part of its service territory?

ii. Please confirm Clearspring's knowledge that, largely through mergers and acquisitions approved by the OEB, Hydro One serves more incorporated cities than does any other Ontario LDC (with this referring to the number of cities versus the population of the cities).

Clearspring Response:

a) Clearspring was first referencing PEG's use of 40% of what PEG terms as "tight" utilities and then 60% of what PEG terms as "loose" utilities in its response to M-Hydro One-21 (d). Clearspring's understanding is that PEG is referencing the percentage of utilities in the sample. PEG decided that 40% of the sampled utilities have "tight" service territories. Although no specific empirical definition of this is provided by PEG, we take "tight" to roughly mean suburban.

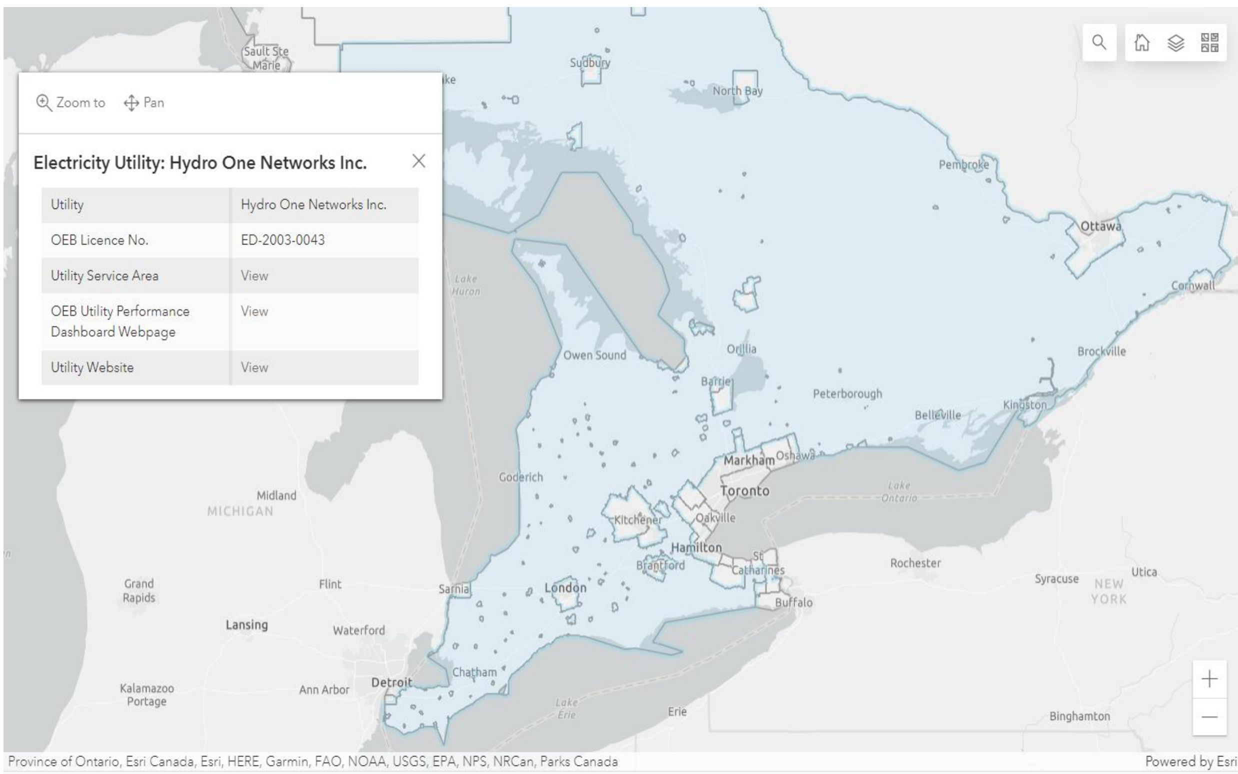
In Clearspring's discussion, we cited PEG's use of these subjective percentages and noted they are used as the basis for estimating Hydro One's service territory in relation to how the U.S. sample has its service territory variable constructed. As Clearspring states on p. 9 of the Joint Report, "It is not clear to Clearspring how PEG made the 40% estimate or why the composition of the sample regarding rural versus suburban utilities should have an impact on Hydro One's estimate for service territory." PEG uses this 40/60 "tight/loose" weighting to help calculate its service territory estimate for Hydro One.

As we stated on p. 9, this subjective weighting scheme does not provide useful information or a proper estimate for Hydro One. If PEG had chosen a 20% suburban value then PEG's estimate approximates Clearspring's area estimate. If they had chosen less than 20% for the suburban value (which Hydro One's service territory clearly is less than 20% suburban and seems to us the more relevant percentage to use), PEG's area calculation scheme produces an area for Hydro One above Hydro One's estimate of 529,313 sq. km.

In summary, our view is that PEG's method of calculating Hydro One's service territory value is unclear, subjective, and not connected to the reality that Hydro One is an extremely rural distributor.

b) Part i: Clearspring should have added "sizeable" and focused on cities in that sentence. Most of the sizeable cities throughout the province are being served by other distributors. The former MEUs are mostly small in relation to the larger cities throughout Ontario that border Hydro One's service territory. Hydro One serves most of Ontario yet nearly all of the sizeable cities (i.e., lower cost areas) have been, and continue to be, carved out of its service area. This meaningfully lowers its customers per area served, especially in relation to the U.S. sample. The U.S. sample that both PEG and Clearspring are using to benchmark Hydro One contains utilities that mostly serve the majority of the sizeable cities throughout their service territories. While there are some municipal utilities in the U.S. that do carve out some cities or towns from the U.S. sample, this is far less pervasive than in Hydro One's case where it does not primarily serve the larger cities in the province and has dozens of cities carved out of its territory.

To help illustrate this, below is a map of southern Ontario and Hydro One's service area from the Ontario Energy Board website. Notice the large cities are served by others and dozens of other cities are carved out of its territory as well, denoted by all the dots. Only two cities cited on this map are primarily served by Hydro One: Brockville and Owen Sound. Both have a population around 22,000.[1] Hydro One does serve some outer parts of Ottawa and Kingston but is not the primary provider for either city.



[1] We note that Peterborough and Orillia are not included in the benchmarking research as being a part of Hydro One during this application. Hydro One does serve other small cities not included on the map. These include Woodstock, Clarence-Rockland, Thorold, and Timmins.

In the Joint Report, Clearspring cited the example of Montana Dakota Utilities (MDU). MDU has the lowest customer per area served in the sample and is even lower than Hydro One using Clearspring's area variable value for Hydro One of 529,313 sq. km. This indicates to us that this area estimate for Hydro One is appropriate, if perhaps not too low, relative to the sample for Hydro One. MDU serves Bismarck, North Dakota which has a population of 73,622 according to the 2020 U.S. Census and most of the other cities and towns throughout its service territory, which includes portions of North and South Dakota, Montana, and Wyoming.[2] Given that MDU is about a tenth of the size of Hydro One (in terms of both area and customers served), we would expect MDU to have less than a tenth of the larger cities served of Hydro One since we are giving MDU credit for being more rural. However, this is not the case. MDU is serving far more larger cities then expected in relation to Hydro One. This provides evidence that the area variable value of 529,313 is not too high and may in fact be conservatively low relative to how the U.S. sample is constructed.

Part ii: While that may be the case, that fact (if true) is unrelated to the issue regarding what value to give Hydro One for its service territory variable in the benchmarking research. The germane issue is the comparison between Hydro One's service territory and those of the U.S. sample to assure a proper variable value is given. Hydro One serves an extremely rural and challenging service territory in relation to the U.S. sample. Despite that fact, the service territory estimate that Clearspring is using implies that Hydro One is not the most rural utility in the sample (MDU is).

[2] Besides Bismarck, other cities served by MDU above 20,000 in population include Dickinson ND, Mandan ND, and Williston, ND.

JR – CANADIAN MANUFACTURERS AND EXPORTERS – 024

Reference:

Joint Report, Page 9

Interrogatory:

At page 9, Clearspring stated that it expected Hydro One to have the lowest customers per square kilometer. However, "Hydro One does not have the lowest customer density using Clearspring's 529,313 sq. km measure. Hydro One's customers per sq. km in 2019 is 2.5, whereas Montana Dakota Utilities ("MDU") is measured at 2.2."

a) Has Clearspring completed any analysis of the population density of Montana, North or South Dakota, Wyoming, or the service territory of Montana Dakota Utilities?

b) If the answer to (a) above is yes, please provide any analysis that has been completed.

Clearspring Response:

a) No specific analysis on the population density of Montana, North or South Dakota, or Wyoming has been completed. The analysis done is the one cited showing that MDU's customers per sq. km is 2.2, revealing that our dataset treats MDU as being more rural than Hydro One.

An analysis of the states themselves would not be relevant since MDU does not serve all (or even the majority) of Montana, Wyoming, and the Dakotas. Instead, rural electric cooperatives serve large rural portions (in terms of area) of those states. MDU does, however, primarily serve Bismarck, North Dakota which has a population of 73,622 (2020 U.S. Census) and other cities and towns. Please see Clearspring's response to JR-OEB-401 (b) for more information regarding the comparison between MDU and Hydro One.

b) Please see response to part a.

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JR – CANADIAN MANUFACTURERS AND EXPORTERS – 025

Reference:

Joint Report, Page 6

Interrogatory:

At page 6, Clearspring stated "Even absent the presence of the large implicit stretch factor and the Company's proposed supplemental stretch factor, Clearspring is not convinced that a supplemental stretch factor would be warranted. Stretch factors are, ideally, a product of total cost benchmarking results and the Company is a very strong cost performer."

a) Please expand on why Clearspring is of the view that differences between HONI and its comparators, for instance the proposed difference in performance incentives, should not be reflected in a supplemental stretch factor. Please explain fully.

Clearspring Response:

a) A principal reason for Clearspring's view of not adding an additional supplemental stretch factor is that a transmission productivity factor of 0.0% already contains a large supplemental (or implicit) stretch factor of over 1%. This is already an extraordinarily high stretch factor — already too high in Clearspring's view — and there is no empirical basis to add another supplemental stretch factor.

   PEG and Clearspring provide results in the Joint Report that Hydro One's transmission total cost performance is strong. PEG finds that Hydro One's transmission total costs during the CIR period are 14.1% below benchmark expectations. Clearspring's results reveal that Hydro One is 31.6% below benchmark expectations. Both results are impressive and place Hydro One into either a 0.15% or 0.00% stretch factor cohort based on Board precedent.

   Based on this precedent, to raise PEG's recommended stretch factor by 0.3% (the amount of PEG's suggested supplemental stretch factor), the Company would need to be at a total cost benchmark score of +10.0% to +25.0%. PEG's total cost results for Hydro One would need to increase by 24.1% relative to the current score of -14.1% to enter a stretch factor cohort that is 0.3% higher using the Board's established stretch factor methodology. The analogous number to raise Clearspring's stretch factor by 0.3% is 21.6%. In Clearspring's view, there is no evidence that the different transmission industry performance incentives in the States are causing total costs throughout the entire U.S. transmission industry to be over 20% higher.

Another point is that Hydro One’s transmission capital age is meaningfully older than the U.S. transmission industry. Dealing with older assets, presents additional challenges for Hydro One beyond those faced by the average U.S. transmitter. However, since the X-factor typically does not include a supplemental stretch factor, Clearspring has not recommended a negative supplemental stretch factor to adjust for Hydro One’s older capital age.

A further point is that the X-factor in all custom IR proceedings, to Clearspring’s knowledge, has only included the base productivity factor and a stretch factor derived from total cost benchmarking results. Adding a new and novel supplemental stretch factor to the X-factor does not have precedent. Beyond that, a capital-related supplemental stretch factor (in addition to the X-factor) has been introduced by the Board in past proceedings and Hydro One is already proposing this 0.15% supplemental stretch factor on capital in this application. Adding a further, fourth stretch factor to the first three (traditional stretch factor derived from total cost benchmarking, the 1% implicit stretch factor, and the 0.15% supplemental stretch on capital) has no basis empirically or from CIR precedent and would further misalign the plan with the principles behind incentive regulation, thus likely exacerbating the need for future custom IRs, higher C-factors, and intensifying the challenges of Hydro One dealing with its older capital age.