OEB Staff

CROSS-EXAMINATION COMPENDIUM

Panel 1

OEB Staff Interrogatory # 123

Issue:

Issue 25: Does the Distribution System Plan adequately reflect productivity gains, benefit sharing and benchmarking?

Reference:

B1-01-01 Section 1.5 Page: 1966-1967

(5.2.3) Productivity and Continuous Improvement, Section 1.5.1 Productivity Savings in the Plan, Table 17 – Detailed Productivity Savings Forecast

Table 17 – Detailed Productivity Savings Forecast

$Millions	2018	2019	2020	2021	2022
Move to Mobile	10.3	10.5	10.7	10.7	10.7
Procurement	14.2	15.3	19.1	20.2	20.5
Telematics	1.0	1.0	2.4	2.8	3.1
Total Capital	**25.5**	**26.8**	**32.2**	**33.7**	**34.5**
Move to Mobile	2.7	2.8	2.9	2.9	2.9
Operations	20.0	23.1	24.1	25.4	28.0
Procurement	2.2	2.1	2.5	2.7	2.5
Customer Service	1.8	2.6	3.2	4.1	4.5
Telematics	0.8	0.8	1.4	1.3	2.2
Information Technology	7.3	9.3	9.3	9.3	9.3
Total OMA	**34.8**	**40.7**	**43.4**	**45.8**	**50.0**
Procurement	1.8	1.8	1.8	1.8	1.8
Administrative	1.4	1.5	1.5	1.5	1.5
Total Corporate Common	**3.2**	**3.3**	**3.3**	**3.3**	**3.3**
Total Savings	**63.5**	**70.8**	**78.9**	**82.8**	**87.8**

Interrogatory:

a) Please provide the detailed calculations used to derive the projected productivity savings identified in Table 17 above.

b) Please describe how Hydro One will track these savings.

c) What assurances do ratepayers have that Hydro One will achieve these forecast savings?

Witness: LOPEZ Chris

.2

Response:

a) The updated evidence filed on December 21, 2017 includes an update to Hydro One's productivity savings forecast that has been embedded into the business plan. A more detailed view of the savings initiatives and the associated assumptions used are included in the table below.

	Category in Rate Filing	Initiative Summary	Measurement and Expected Benefit	Updated Savings 2018	2019	2020	2021	2022
Capital	Move to Mobile	Move to Mobile (Field Force)	Measures Labour Hours per Unit - Historical Baseline vs Actual *Plan allocation to expected unit cost savings in New Connections, Joint Use line Relocations, Pole Replacement, Field Meter Service, Component Replacement*	$ 10.3	$ 10.5	$ 10.7	$ 10.7	$ 10.7
Capital	Procurement	Procurement	Lower Cost per Unit - Historical Baseline vs Actual *Savings are estimated at a category level based on historical spend, expected and achieved negotiated savings, and updated per business plan assumptions (Capital program spend)*	$ 12.7	$ 13.2	$ 17.0	$ 16.7	$ 18.6
Capital	Information Technology	ISD Savings	Infrastructure Rationalization/Contract Reductions *Expected capital allocation of negotiated reductions*	$ -	$ 0.3	$ 0.3	$ 0.3	$ 0.3
Capital	Operations	Stations Efficiencies	Cost Reduction based on Historical spend *Expected Capital allocation based on historical spend for OT reductions and Stations efficiencies*	$ 0.01	$ 0.01	$ 0.01	$ 0.01	$ 0.01
Capital	Telematics	Telematics	Fleet Rationalization - Unit Based Capital Plan Reduction *Estimated by utilizing Telematics data on fleet utilization and then measures the expected unit based reduction in the capital plan*	$ 13.4	$ 10.1	$ 9.8	$ 9.6	$ 9.3
OM&A	Customer	eBilling	Lower Cost per Customer *Expected customers enrolled in eBilling x Unit Savings*	$ 1.8	$ 2.6	$ 3.2	$ 4.1	$ 4.8
OM&A	Information Technology	ISD Savings	Infrastructure Rationalization/Contract Reductions *Expected savings from server/database decommissioning and negotiated infrastructure and application maintenance contract reductions*	$ 7.4	$ 8.3	$ 11.5	$ 11.5	$ 11.5
OM&A	Information Technology	Contract Rates - Minor Enhancement	(Old Rate - New Rate) * Expected ME Hours *Negotiated savings x Expected need for minor enhancement hours in business plan*	$ 0.9	$ 1.0	$ 0.9	$ 0.9	$ 0.9
OM&A	Information Technology	Telecom Services Contracts	Lower Cost per Contract *Reflects negotiated reduction in contract price*	$ 0.6	$ 0.7	$ 0.7	$ 0.7	$ 0.7
OM&A	Move to Mobile	Move to Mobile (Clerical)	FTE Reduction *Reflects expected reduction in 29 back office support staff by 2020*	$ 2.7	$ 2.8	$ 2.9	$ 2.9	$ 2.9
OM&A	Operations	Cable Locate Outsourcing	(Historical Cost - New Cost) * # of Units *Reflects negotiated savings for planned units being outsourced*	$ 7.6	$ 7.8	$ 7.9	$ 8.1	$ 8.2
OM&A	Operations	Fault Indicator Deployment	Lower Labour Hours per Unit *Estimate based on expected time savings for responding to a line fault. Tracked using historical data compared to actual response time*	$ 0.8	$ 0.8	$ 0.8	$ 0.8	$ 0.8
OM&A	Operations	Forestry Initiatives	Lower Cost per KM *Estimated based on reductions in cost due to staff policy for indement weather and expected overall unit volume reduction in trouble calls*	$ 2.8	$ 4.1	$ 5.9	$ 6.9	$ 7.9
OM&A	Operations	Stations Efficiencies	Cost Reduction based on Historical spend *Expected OM&A allocation based on historical spend for OT reductions and Stations efficiencies*	$ 0.3	$ 0.4	$ 0.4	$ 0.4	$ 0.4
OM&A	Operations	Engineering Work Team Migration	FTE Reduction *A reduction in support staff that was utilizing the legacy software*	$ 1.3	$ 1.3	$ 1.3	$ 1.3	$ 1.3
OM&A	Operations	Flexible Bill Window	Lower Cost per Unit for Meter Reads *Expected savings from a unit reduction in demand for manual meter reads and lower unit cost due to gained scheduling efficiencies*	$ 1.5	$ 1.5	$ 1.5	$ 1.5	$ 1.5
OM&A	Procurement	Procurement	IT Software Cost Reduction *Reflects expected and negotiated savings*	$ 0.9	$ 1.7	$ 2.6	$ 2.6	$ 2.6
OM&A	Telematics	Telematics	Lower Liters of Fuel per KM *Reflects results of pilot program with expected reduction in Liters of fuel per KM driven*	$ 0.8	$ 0.8	$ 1.4	$ 1.3	$ 2.2
CCC	Administrative	Corporate Common Head Count Reductions	FTE Reduction *Identified headcount reductions by position in Corporate Common*	$ 1.7	$ 1.9	$ 1.9	$ 1.9	$ 1.9
CCC	Procurement	Procurement	Lower Cost *Realized reduction in contracted spend in Corporate Common*	$ 2.3	$ 2.3	$ 2.3	$ 2.3	$ 2.3
Total	Capital			$ 36.4	$ 34.2	$ 37.8	$ 37.3	$ 39.0
Total	OM&A			$ 29.4	$ 33.7	$ 40.9	$ 42.9	$ 45.5
Total	Corporate Common			$ 4.0	$ 4.2	$ 4.2	$ 4.2	$ 4.2

b) Hydro One's productivity governance and associated reporting processes are maintained by Finance. Hydro One has implemented a robust governance structure around productivity reporting to ensure productivity savings are accurately reflected on corporate scorecards and that there is continuity of savings in the Business Plan.

All productivity initiatives are approved by Finance prior to reporting any actual savings on corporate scorecards and are audited for compliance throughout the year. Approval by Finance ensures that each initiative is tracked using a detailed calculation methodology.

Finance reviews all productivity reporting to ensure each initiative meets the following criteria:

- Consistently documented (detailed description/logic, identified systems/dependencies, clear calculation methodology/data source and reasonable exclusions/adjustments);
- Auditable with an applicable baseline for reporting;
- In line with Hydro One's definition of productivity ('hard' savings and not cost avoidance); and
- Reviewed and approved by a VP or delegate.

Productivity achievement is reported to the Executive Leadership Team on a monthly basis and is included as a metric on Hydro One's Team Scorecard for management staff.

c) Ratepayers are assured through Hydro One's commitment to achieving the forecast savings targets. This commitment is demonstrated by:

i. The enhanced governance and visibility in Hydro One's productivity reporting process;
ii. Incremental productivity savings being identified in the updated evidence filed on December 21st, 2017;
iii. Embedding the forecast savings into the business plan which puts the achievement risk on Hydro One's Net Income and not on the ratepayer;
iv. Including the savings and associated net income targets on the Team scorecard for management staff; and
v. Ratepayers are protected through the Custom Incentive Rate mechanism which allows for increases in OM&A, limited to inflation less productivity. If Hydro One fails to achieve its productivity savings it will not impact customer rates.

Witness: LOPEZ Chris

Productivity Savings from Staff-123

Productivity Savings Forecast - OM&A

	2018	2019	2020	2021	2022	Total
Total OM&A - As filed	34.8	40.7	43.4	45.8	50	214.7
Total OM&A - Updated	29.4	33.7	40.9	42.9	45.5	192.4
$ Change	5.4	7	2.5	2.9	4.5	22.3
% Change	15.5	17.2	5.8	6.3	9.0	10.4

Productivity Savings Forecast - Capital

	2018	2019	2020	2021	2022	Total
Total Capital - As filed	25.5	26.8	32.2	33.7	34.5	152.7
Total Capital - Updated	36.4	34.2	37.8	37.3	39	184.7
$ Change	-10.9	-7.4	-5.6	-3.6	-4.5	-32
% Change	-42.7	-27.6	-17.4	-10.7	-13.0	-21.0

Productivity Savings Forecast - Corporate Common

	2018	2019	2020	2021	2022	Total
Total Corp Common - As filed	3.2	3.3	3.3	3.3	3.3	16.4
Total Corp Common - Updated	4	4.2	4.2	4.2	4.2	20.8
$ Change	-0.8	-0.9	-0.9	-0.9	-0.9	-4.4
% Change	-25.0	-27.3	-27.3	-27.3	-27.3	-26.8

Productivity Savings Forecast - Total

	2018	2019	2020	2021	2022	Total
Total - As filed	63.5	70.8	78.9	82.8	87.8	383.8
Total - Updated	69.8	72.1	82.9	84.4	88.7	397.9
$ Change	-6.3	-1.3	-4	-1.6	-0.9	-14.1
% Change	-9.9	-1.8	-5.1	-1.9	-1.0	-3.7

$m	2018	2019	2020	2021	2022
Capital-Productivity Savings	36.4	34.2	37.8	37.3	39
Capital Spending Forecast (DSP)	633.9	756.8	719	740.7	827.2
Percentage	5.74	4.52	5.26	5.04	4.71
OM&A-Productivity Savings	29.4	33.7	40.9	42.9	45.5
OM&A Forecast	576.7	593.3	601.9	610.6	630.4
Percentage	5.10	5.68	6.80	7.03	7.22

Source: Capital Spending Forecast Exh B1-1-1, DSP Section 1.1, p. 13, Table 2, OM&A Forecast 2018 E I Tab 38 Sch SEC-70, p. 2, 2019-2022 E A Tab 3 Sch 2, p.6, Table 1 condition warrants replacement. A summary of Hydro One's capital expenditure plan by these four categories is provided in Tables 2 and 3 below.

Table 2: 2018 – 2022 Capital Spending Forecast ($ Million)

Category	**2018**	**2019**	**2020**	**2021**	**2022**
System Access	154.6	157.6	160.9	165.9	170.0
System Renewal	248.6	318.7	336.7	362.5	451.1
System Service	81.8	93.4	85.6	78.8	69.5
General Plant	149.0	187.1	135.8	133.4	136.6
Total	**633.9**	**756.8**	**719.0**	**740.7**	**827.2**

Table 3: 2018 – 2022 Capital Spending Forecast (% by Category)

Category	**2018**	**2019**	**2020**	**2021**	**2022**
System Access	24%	21%	22%	22%	21%
System Renewal	39%	42%	47%	49%	55%
System Service	13%	12%	12%	11%	8%
General Plant	23%	25%	19%	18%	17%
Total	**100%**	**100%**	**100%**	**100%**	**100%**

Response:

a) [C1-1-1] Tables 1

Table 1: Summary of Recoverable OM&A Expenses ($ Millions)

Description	Historic					Bridge		Test
	2014 IRM	2015		2016		2017		2018
	Actual	Actual	Approved	Actual	Approved	Actual	Approved	Forecast
Sustainment	325.7	304.6	316.5	323.7	361.4	304.7	367.1	346.7
Development	11.0	10.9	15.4	11.9	17.8	8.8	17.0	11.0
Operations	29.5	27.6	35.8	31.5	39.4	31.9	37.5	36.7
Customer Care	209.3	155.4	111.7	118.8	110.9	123.4	111.6	128.7
Common Corporate Costs and Other	94.4	69.1	59.0	72.0	54.8	84.9	54.7	53.9
Property Taxes & Rights Payments	4.6	4.8	4.7	4.6	4.9	5.0	5.0	4.9
Total	**674.5**	**572.5**	**543.1**	**562.6**	**589.1**	**558.7**	**593.0**	**576.7**
% Change (year-over-year)		*-15.1%*	*-19.5%*	*-1.7%*	*8.5%*	*-0.7%*	*0.7%*	*2.1%*
% Change (Test vs. 2016 Actual)						*-0.7%*		*2.5%*

"Approved" figures reflect OEB-directed reductions to Sustainment OM&A and Common Corporate Costs and Other OM&A line items (specifically, budgets for vegetation management, LEAP funding, and compensation).

b) [C1-1-2] Tables 1-5

Please see Exhibit I-38-AMPCO-037.

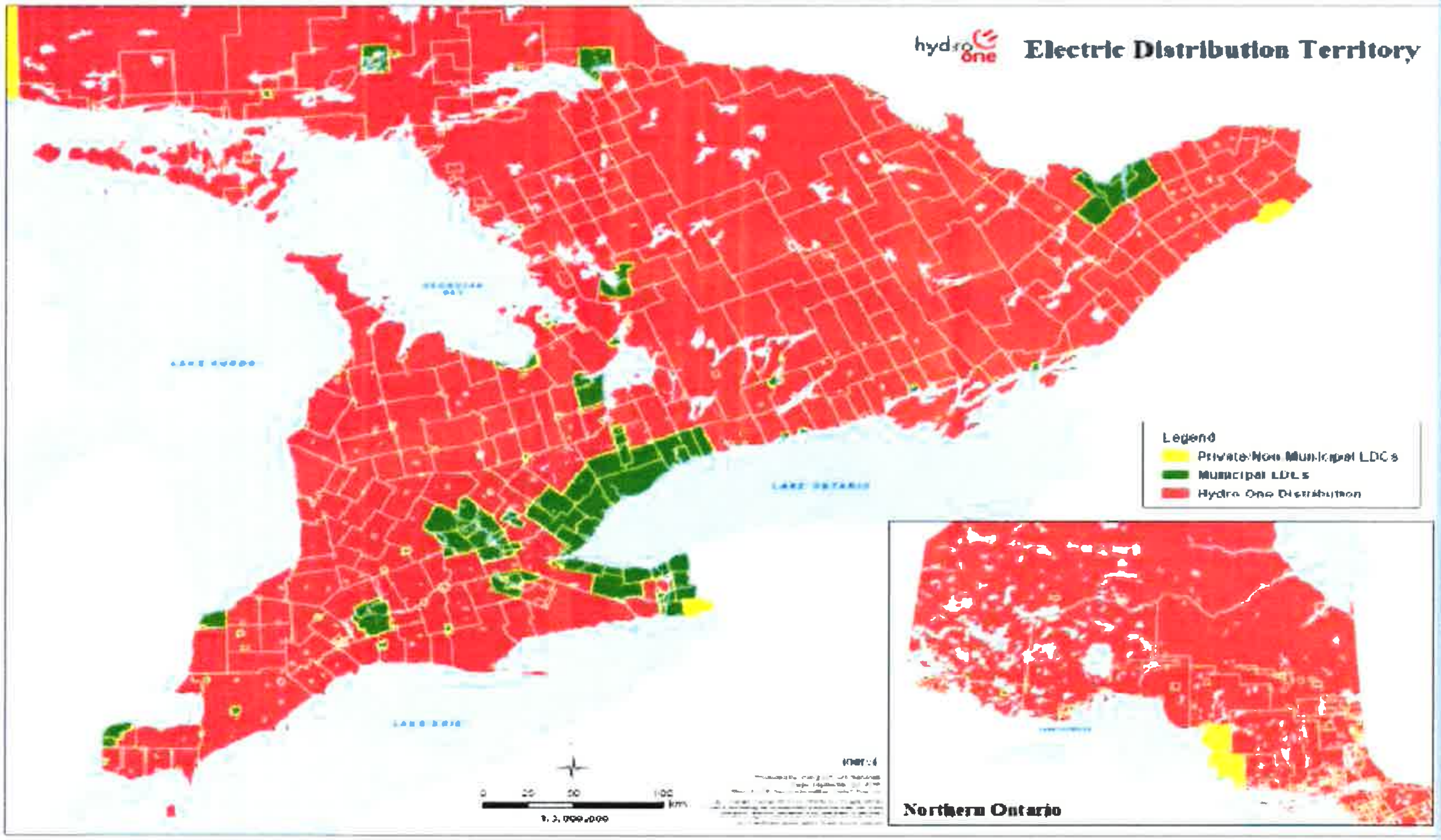
c) [C1-1-3] Table 1

Table 1: Summary of Development OM&A ($ Millions)

Description	Historic					Bridge		Test
	2014	2015		2016		2017		2018
	Actual	Actual	Approved	Actual	Approved	Actual	Approved	Forecast
Engineering and Technical Studies	4.0	3.8	4.7	4.2	4.7	3.5	4.7	1.7
Distributed Generation Connections	2.6	2.5	2.2	2.5	2.0	2.6	2.0	2.9
Distribution Standards Program	3.9	3.4	5.6	3.3	5.8	0.9	6.0	4.5
Research Development and Demonstration*	0.4	1.2	2.9	1.8	5.2	1.7	4.3	1.6

Witness: JODOIN Joel, GARZOUZI Lyla, IRVINE Tom, MERALI Imran

Distribution System Map



33

Distribution System Stats

Service Territory	Rural Service Area - 960,123 sq. km Urban Service Area - 677 sq. km
Customers	1.3 million residential and business customers as well as 55 local distribution companies
Distributed Generation	Approximately 13,400 small, mid-size and large embedded generators connected to Hydro One's distribution network, including approximately 12,600 generators with capacities of up to 10 kW and 1,600 generators pending connection
Stations	Approximately 1,000 distribution and regulating stations
Circuit Length	123,000 kilometres of primary low voltage distribution lines

8

Ontario

Ontario Fact Sheet
April 2018

Land and Freshwater Area (in sq kms)

Land	917,741
Freshwater	158,654
Total area	1,076,395
Total land in census farms (%)	5.6

Capital – Toronto*

2017 Estimated population	6,346,088

* Census Metropolitan Area

Economy, 2017

GDP ($ Millions, Nominal)	830,302
% of Canada	38.7
Primary household income ($ Millions)	547,633
% of Canada	38.7
Primary household income per capita ($)	
Ontario	38,584
Canada	38,574
CPI inflation, 2017	1.7%

Distribution of GDP, 2016 (%)

Goods	22.5
Of which: Manufacturing	11.9
Services	77.5

Top Five International Export Markets, 2017 (% Share)

United States	80.2
United Kingdom	7.2
China	1.6
Mexico	1.5
Japan	0.8

Top Five International Exports, 2017 (% Share)

Motor vehicles & parts	35.5
Mechanical equipment	10.1
Precious metals & stones	9.7
Electrical machinery	3.9
Plastic Products	3.6

Population

July 1, 2017	14,193,384
% of Canada	38.7
Average annual growth, 2007-2017 (%)	1.1
Life expectancy (Years), 2014	
Male	80.4
Female	84.4
Labour force, 2017	7,579,800
Employment, 2017	7,128,000
Job creation, 2017	128,400
Unemployment rate, 2017	6.0%

Population Profile, 2016 (% Distribution)

Canadian born	69.4
Foreign born	29.1
Immigrated before 2001	18.3
Immigrated between 2001 & 2016	10.8
Non-permanent residents	1.5

Total Trade, 2017 ($ Millions)*

Exports	415,376
Imports	412,812
Trade balance	+2,563

* International+Interprovincial

Top Five International Import Suppliers, 2017 (% Share)

United States	55.4
China	12.4
Mexico	8.2
Japan	3.8
Germany	2.5

Top Five International Imports, 2017 (% Share)

Motor vehicles & parts	22.5
Mechanical equipment	14.5
Electrical machinery	11.4
Plastic Products	3.9
Pharmaceutical products	3.4

Macroeconomics and Revenue Branch
Office of Economic Policy, Ontario Ministry of Finance

.10

ᐊᐧᐅᓂᑲᓂᔭᑊ Wataynikaneyap Power

MAY 2018 ISSUE

POWERTEL

BUILDING CONNECTIONS

PIKANGIKUM POWER LINE PROJECT

High-Level Project Schedule

Previous Milestones
- 25kV line and anchor installation is complete
- All required line equipment has been purchased

May 2018
- Begin installing steel poles
- Substation construction has started
- Start framing wood pole structures in the air

July 2018
- Line foundation complete

September 2018
- Final site inspection and restoration

October 2018
- Substation construction complete

November 2018
- Line construction complete

December 2018
- Line energization

MAY UPDATE FROM POWERTEL

THE 25 KV PORTION OF THE LINE FROM THE SUBSTATION UP TO PIKANGIKUM IS complete and progress continues on the 115 kV portion of the line along Taxi Bay Road and the Nungesser Road. Clearing of the Right of Way is complete with the exception of some smaller, environmentally sensitive areas which will be cleared in the future. As we build the line, on-the-job training continues for all of our employees. Last month the training included Forest Fire Training, Traffic Control Training, ATV Rider Awareness, and Standard First Aid.

Construction continues by PowerTel and their Subcontractors on the line to Pikangikum.

For Project information, please visit our website: www.pikangikumpowerlineproject.com

May 2018 Issue

PIKANGIKUM POWER LINE PROJECT

Visiting Eenchokay Birchstick School

The Project Training Team and PowerTel visited EBS for a career fair with the students on April 24th.

THE PIKANGIKUM EENCHOKAY BIRCHSTICK SCHOOL (EBS) CAREER Fair was held April 24th and was an excellent event with attendance from over 400 youth ranging from grades 4 to 12. The Project Team was happy to be invited to present updates to the students, highlight safety and promote involvement in the project through the training initiative. PowerTel staff were also thrilled to be involved in the Career Fair and brought along electrical tools, parts and gear for students to explore and try on. A big Thank-You goes out to the staff and organizers for having us! The future of the Power Line Trades looks bright with such a great group of kids taking interest!

Please see some of the excellent power line art contest entries below, received from students in grades 7 & 8.

CONTACT US

PowerTel

PowerTel invites all interested Candidates to forward their resumes to:

Ashley Lawrence
E: jobs@powertel.ca
P: 1 (705) 866-2825 Ext. 1007

Your Community Contact

Jonah Strang
P: (807) 728-3287
E: jonahstrang@hotmail.com

EMAIL GENERAL PROJECT INQUIRIES TO:
pikproject@wataypower.ca

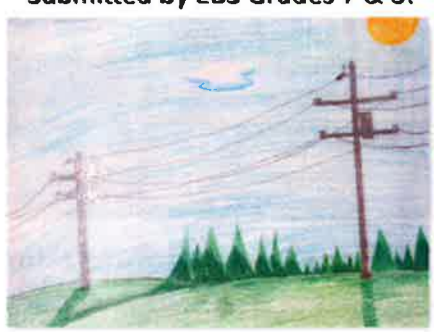
Learn more about the **Wataynikaneyap Power Training Program**, contact:

Marlon Gasparotto
OSLP Training Coordinator
P: (807) 474-3300
E: m.gasparotto@oslp.ca

Power Line Artwork

Submitted by EBS Grades 7 & 8!

Artist: Cheryl Keeper



Artist: Danica Turtle

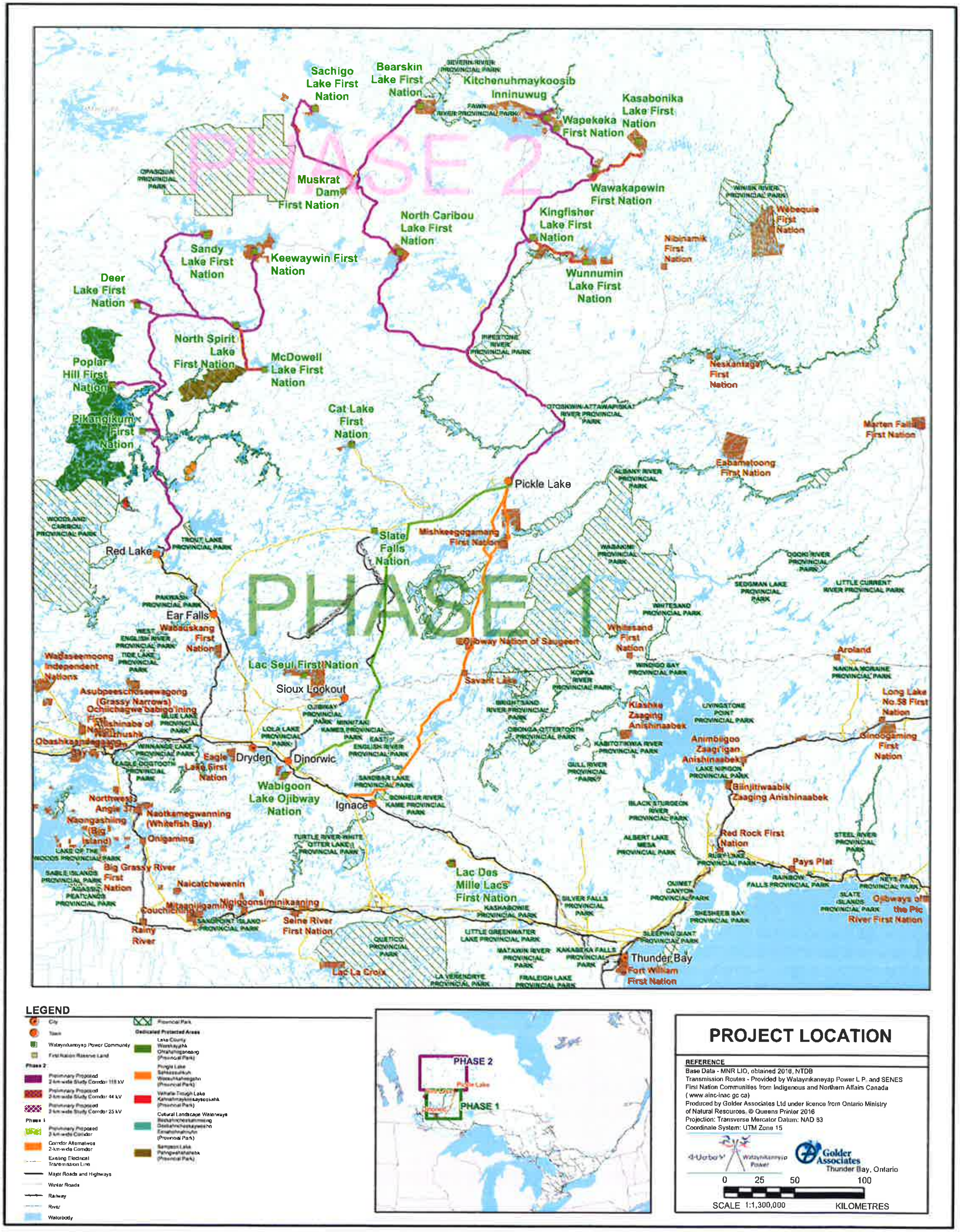
Artist: Katrina Turtle

Interested in the Project? Explore our Website & Facebook Page for more information!

https://www.pikangikumpowerlineproject.com/

Pikangikum Power Line Project

.12


PHASE 2
PHASE 1
Sachigo Lake First Nation
Bearskin Lake First Nation
Kitchenuhmaykoosib Inninuwug
Kasabonika Lake First Nation
Wapekeka First Nation
Muskrat Dam First Nation
Wawakapewin First Nation
North Caribou Lake First Nation
Kingfisher Lake First Nation
Wunnumin Lake First Nation
Nibinamik First Nation
Webequie First Nation
Sandy Lake First Nation
Keewaywin First Nation
Deer Lake First Nation
North Spirit Lake First Nation
McDowell Lake First Nation
Poplar Hill First Nation
Pikangikum First Nation
Cat Lake First Nation
Neskantaga First Nation
Marten Falls First Nation
Eabametoong First Nation
Pickle Lake
Slate Falls Nation
Mishkeegogamang First Nation
Red Lake
Ear Falls
Wabauskang First Nation
Lac Seul First Nation
Sioux Lookout
Whitesand First Nation
Ojibway Nation of Saugeen
Savant Lake
Aroland
Long Lake No.58 First Nation
Ginoogaming First Nation
Animbiigoo Zaagi'igan Anishinaabek
Biinjitiwaabik Zaaging Anishinaabek
Red Rock First Nation
Pays Plat
Ojibways of the Pic River First Nation
Wabaseemoong Independent Nations
Asubpeeschoseewagong (Grassy Narrows)
Obashkaandagaang
Eagle Lake First Nation
Dryden
Dinorwic
Wabigoon Lake Ojibway Nation
Ignace
Northwest Angle 37
Naotkamegwanning (Whitefish Bay)
Onigaming
Big Grassy River First Nation
Naicatchewenin
Couchiching
Mitaanjigamiing
Nigigoonsiminikaaning
Seine River First Nation
Rainy River
Lac La Croix
Lac Des Mille Lacs First Nation
Thunder Bay
Fort William First Nation
LEGEND
PROJECT LOCATION
REFERENCE
Base Data - MNR LIO, obtained 2016, NTDB
Transmission Routes - Provided by Wataynikaneyap Power L.P. and SENES
First Nation Communities from Indigenous and Northern Affairs Canada
(www.ainc-inac.gc.ca)
Produced by Golder Associates Ltd under licence from Ontario Ministry of Natural Resources, © Queens Printer 2016
Projection: Transverse Mercator Datum: NAD 83
Coordinate System: UTM Zone 15
Wataynikaneyap Power
Golder Associates
Thunder Bay, Ontario
0 25 50 100
SCALE 1:1,300,000
KILOMETRES

.13

Ontario

ONTARIO ENERGY BOARD

FILE NO.:	**EB-2017-0049**	**Hydro One Networks Inc.**

VOLUME:	**Technical Conference**
DATE:	**March 1, 2018**

Canadian-specific levelization. It was only for the escalation method that we used the ECI.

DR. LOWRY: Speaking of those levelizations, did you use -- how did you levelize the REC data? How did you come up with input price levels for the REC data?

MR. FENRICK: Same procedures as with the investor-owned utilities, and Hydro One, where we looked at Bureau of Labour statistics, composites of what occupations are aggregated to make a transmission and distribution utility, you know, so the percentage of management positions, percent of what -- you know, a whole host of occupations. And we mapped that to the specific cities served by the utilities and then constructed it in the same manner.

DR. LOWRY: Now, speaking of the specific cities, did you do that for Hydro One as well? I know there are a lot of cities served. Or did you use just Ontario numbers?

MR. FENRICK: Just Ontario numbers. We basically said Hydro One serves all of Ontario and used Ontario numbers.

DR. LOWRY: Is it reasonable to assume that the wage rates paid by Hydro One are reasonably approximated by those for the province in view of the fact that it doesn't serve Windsor or the Toronto area or the Ottawa area?

MR. FENRICK: Yes, I think that is a reasonable assumption.

DR. LOWRY: Okay. Now, my next question, something caught my eye when I looked at that table, data set averages for most recent year. And I know that you included the RECs in the study to add more companies that had low customer density and perhaps for a few other reasons, more rural in general. But it caught my eye that the value of the square kilometre per customer variable was 0.765 for Hydro One and was 0.159 for the RECs. And, you know, if you're comparing Hydro One -- and now we're talking the new Hydro One that's acquired, you know, a lot more communities than they had in the past that aren't in such remote areas -- it just surprised me that Hydro One's value for that was so much higher than that of the RECs.

And so one question I have is, can you, you know, comment on the reasonableness of that; but secondly, it gets me to wondering about how square kilometres are calculated for Hydro One compared to how they're calculated for the RECs and for other companies in the U.S. part of the sample.

And it kind of gets back to the same area: Are you just counting a service territory defined as, you know, pretty close to where the wires are, or is it a broad region where in fact, you know, there are some pretty big chunks of territory where there are very few distribution wires?

MR. FENRICK: The first comment I'd make is, well, yes, Hydro One's value is .765 and the REC average value is .159. There is certainly diversity in that REC value. That's an average. There's rural electric cooperatives that are below that number and then also well above that number, and so --

DR. LOWRY: Could I just ask about that, Steve?

Because I didn't look real closely at that REC list. I mean, are there, you know, a lot of RECs from the rural east that are -- you know, where things are not quite as spread out that would pull that number down? I was thinking of the RECs as being more out in North Dakota or something.

MR. FENRICK: Right. There are -- there's 900-some RECs in the U.S., so there's a huge variance, if you will, of density from, as you mentioned, some on the east coast that have higher density values and then there are certainly ones that are much lower density. So it is a mixed bag.

I'm trying to think of -- there was an IR that asked about these conditions and how Hydro One compares. And there were rural electric cooperatives that were less dense than Hydro One when we examined that.

DR. LOWRY: So then can you address how Hydro One estimated its service territory?

MR. FENRICK: This gets to a prior answer, where it was the broad definition of the service territory of Hydro One. If you think about the fact they have to -- you know, maybe there are small little pockets of customers, but that's an enormous cost driver for Hydro One to be serving those pockets throughout its service territory. You know, it's got to have lines to run to those customers and provide service.

And so while you're right, there are probably some land areas in that that there are no customers, you know, where there are pockets and there's a few customers here and a few customers there, that's an enormous cost driver to Hydro One and is rightly put into the econometric model that way.

DR. LOWRY: So the square miles that was put in for -- in calculating this variable for Hydro One, did that come off of the GPS work? Or was this an independent calculation?

MR. FENRICK: Just to clarify, GIS -- it was the GIS work that we used to -- and it was the same Platt's data that we used for Hydro One as well as the rest of the sample. So there wasn't a Hydro One estimate. It was the -- using the GIS mapping to be consistent from Hydro One and the rest of the U.S. sample.

DR. LOWRY: Okay.

MR. NETTLETON: Mark, it's Gord Nettleton. Just one clarification that I would point out that was a premise to the -- I think a premise to your question related to the acquireds, that Hydro One acquired utilities that Hydro One has obtained. I'm just wanting to make sure that we're all on the same page, that the acquireds are not being integrated into Hydro One from a rate-making perspective until midway through this rate period and certainly would not have been reflected in the 2015 data that we're speaking of here.

MR. SHEPHERD: Can I just interject there, Mark, before you respond. There are, of course, 88 acquireds prior to that, right? And those are integrated.

MR. NETTLETON: Yes.

MR. SHEPHERD: And they're all small towns, exactly what Mr. Lowry was talking about. That's -- I just wanted to clarify that. Thanks, Mark.

DR. LOWRY: Okay. Sorry, I'm looking through here just trying to see what the best use of the next 15 minutes is.

OEB Staff Interrogatory No. 41 next, issue 10. Let me know when you're ready.

MR. FENRICK: I think we're ready, Mark.

DR. LOWRY: Okay. So the comment here was, your answer to part E, is you state "the pension and benefit expenses are not itemized on Form 7." And that prompts me to ask, well, is this then the reason that pension and benefits expenses are included in the benchmarking study?

MR. FENRICK: It's certainly one of the reasons. We couldn't exclude the pension and benefits from the rural electric cooperatives. We also, looking back at the Toronto Hydro custom incentive regulation proceeding, excluding pensions wasn't done by either us or PEG in the reply to our study. So using that as basis, we didn't exclude the pensions and benefits.

DR. LOWRY: But isn't it the case that Hydro One is proposing to Y factor pension expenses, so that the price cap -- the revenue cap index does not apply to pensions?

MR. NETTLETON: Mark, just for clarification, are you referring to the reg asset?

DR. LOWRY: That may be how it's termed, because I

- The challenge posed by low customer density is a major issue when benchmarking the cost of Hydro One. The customer density variable that PSE used is service territory area/customer.[23] Service territory area is difficult to calculate accurately. A threshold issue in these calculations is whether the territory is the area which the utility must *stand ready* to serve if demand arises or the (often much smaller) area it *actually* serves. The former approach is easier to implement but less accurate. In the technical conference, Mr. Fenrick stated that PSE took the former approach.[24] Hydro One's customer density is reported to be far lower than the average for the rural electric cooperatives in the sample. The service territory estimate for Hydro One exceeds the entire land area of Ontario. Alternative density variables are available. PEG used overhead line miles per customer as the density variable in a recent power distributor cost benchmarking study for Alberta's Utilities Consumer Advocate ("UCA").[25] The value of this variable will tend to be high for distributors serving rural areas and low for distributors serving urban areas.

- One cost *advantage* of a rural distributor is extensive overheading of facilities, which saves on capital cost. Our research indicates that distributors with extensive overheading tend to have lower capital cost and total cost. There is no overheading variable in PSE's model.

- The PSE benchmarking study is unusual for including data from numerous US regional electric cooperatives in the sample, yet it excludes data for Ontario distributors that serve rural areas (e.g., Algoma Power) and report their costs in Canadian currency. REC data do have some advantages in a study of the cost performance of Hydro One.

    - RECs typically have low customer density like Hydro One. Inclusion of REC data in the sample to that extent increases the precision of forecasts of the cost of Hydro One. REC data are particularly desirable for estimating the parameter of the cost model's density variable.

    - Data on peak loads of RECs may be better than those available for US IOUs.

The REC data also have noteworthy limitations. Three of these are especially important.

---

[23] Fenrick, Benchmarking Study, *op. cit.*, p. 11.

[24] Transcript, Technical Conference, March 1, 2018, *op. cit.*, p.46, line 17-p.47, line 4.

[25] Pacific Economics Group Research (2018). *Benchmarking the Performance of Alberta Power Distributors*, for Utilities Consumer Advocate of Alberta, February 2018.

.20

The OM&A (line 9) provided for each year in Table 1 is determined based on the 2018 forecast provided in the Application and increased by the Inflation Factor ("I") and reduced by the proposed Productivity Factor ("X"), for a total increase of 1.45% per annum.

Table 1: Summary of Revenue Requirement Components ($ Million)

Line		Reference	2018	2019	2020	2021	2022
1	Rate Base	D1-1-1	7,671.6	8,049.8	8,477.9	9,036.5	9,436.6
2	Return on Debt	E1-1-1	191.6	201.1	211.8	225.7	235.7
3	Return on Equity	E1-1-1	269.4	282.7	297.7	317.4	331.4
4	Depreciation	C1-6-2	392.6	413.5	428.6	448.1	463.0
5	Income Taxes	C1-7-2	61.5	64.7	66.4	72.7	72.7
6	Capital Related Revenue Requirement		915.1	962.0	1,004.5	1,063.9	1,102.8
7	Less Productivity Factor (0.45%)			(4.3)	(4.5)	(4.8)	(5.0)
8	**Total Capital Related Revenue Requirement**		**915.1**	**957.7**	**1,000.0**	**1,059.1**	**1,097.8**
9	OM&A	C1-1-1	584.8	593.3	601.9	610.6	630.4
10	Integration of Acquired Utilities	A-7-1				10.7	
11	**Total Revenue Requirement**		**1,499.9**	**1,551.0**	**1,601.9**	**1,680.4**	**1,728.2**
12	Increase in Capital Related Revenue Requirement			42.6	42.3	59.1	38.8
13	Increase in Capital Related Revenue Requirement as a percentage of Previous Year Total Revenue Requirement			2.84%	2.73%	3.69%	2.31%
14	Less Capital Related Revenue Requirement in I-X			0.88%	0.90%	0.91%	0.91%
15	**Capital Factor**			**1.96%**	**1.83%**	**2.78%**	**1.39%**

The 2018 Total Revenue Requirement of $1,499.9 million (line 11) is determined based on a forward test year, cost of service approach and is the rebasing year for this Application.

In 2019, the Capital Related Revenue Requirement (line 6) increases to $962.0 million versus $915.1 million in 2018. Hydro One will reduce the Capital Related Revenue Requirement (line 6) by the proposed Productivity Factor of 0.45% or $4.3 million (line 7), such that the Total Capital Related Revenue Requirement is $957.7 million (line 8). The change in Total Capital Related Revenue Requirement (line 8) in 2019 versus 2018 is $42.6 million (line 12). This difference is equal to 2.84% of the 2018 Total Revenue Requirement of $1,499.9 million ($42.6 million divided by $1,499.9 million).

The 2.84% increase in Total Capital Related Revenue Requirement is the total increase in revenue requirement arising from the higher 2019 Capital Related Revenue Requirement (line 6). However, the 2.84% increase must be offset by the increase in revenue requirement that results from the application of the Inflation and Productivity Factors (I - X) of the RCI. This is done by determining the percentage of the Total Capital Related Revenue Requirement (line 8) that is already provided for by the Inflation and Productivity Factors. In 2019, this equals 0.88% ($915.1 million x 1.45% / $1,499.9 million). The net result of 1.96% (2.84% less 0.88%) is the 2019 Custom Capital Factor. The calculation of the Custom Capital Factor for each of 2020 through 2022 is the same, as set out in Table 1 above.

1.4 REVENUE CAP INDEX SUMMARY

Table 2 below summarizes the Custom Revenue Cap Index by Component that Hydro One is proposing to use in this Application to determine Total Revenue Requirement for rate-making purposes for 2019 through 2022.

Table 2: Custom Cap Index (RCI) by Component (%)

Custom Revenue Cap Index by Component	2019	2020	2021	2022
Inflation Factor (I)	1.90	1.90	1.90	1.90
Productivity Factor (X)	-0.45	-0.45	-0.45	-0.45
Capital Factor (C)	1.96	1.83	2.78	1.39
Custom Revenue Cap Index Total	3.41	3.28	4.23	2.84

Table 3 below summarizes the Total Revenue Requirement that would result from the Board's approval of Hydro One's Custom IR, were the Application to be approved as filed.

Table 3: Revenue Requirement by Year

Year	Formula	Revenue Requirement
2018	Cost of Service	$1,499.9 million
2019	2018 Revenue Requirement x 1.0336	$1,551.0 million
2020	2019 Revenue Requirement x 1.0328	$1,601.9 million
2021*	2020 Revenue Requirement x 1.0423 + 10.7M	$1,680.4 million
2022	2021 Revenue Requirement x 1.0284	$1,728.2 million

*Hydro One is proposing to update the 2021 Total Revenue Requirement with updated cost of capital parameters.

1.5 INTEGRATION OF ACQUIRED UTILITIES

Since its last rebasing application, Hydro One has acquired Norfolk, Haldimand and Woodstock. Consistent with the Board's Mergers, Acquisitions, Amalgamations, and Divestitures ("MAADs") Decisions and ratemaking policies, the Acquired Utilities are currently separate from Hydro One for rate-making purposes. As outlined in Exhibit A, Tab 7, Schedule 1, Hydro One proposes to integrate the Acquired Utilities effective January 1, 2021. As set out in Exhibit G1, Tab 2, Schedule 1, Hydro One will introduce six new rate classes at that time.

Consistent with the Board's MAADs policies, the financial information and the associated revenue requirement relating to the Acquired Utilities have been excluded from Hydro One's financial information for the test years prior to 2021. For the 2021 and 2022 test years, all financial information presented in this Application includes costs relating to both Hydro One and the Acquired Utilities.

This means that the gross fixed assets and accumulated depreciation of the rate base of the Acquired Utilities has been added to the opening balance of Hydro One's gross fixed assets and accumulated depreciation, respectively, effective January 1, 2021. The resulting increase in rate base of $168.4 million (Exhibit D1, Tab 1, Schedule 1) and capital expenditures is reflected in lines 1 through 6 of Table 1 above and captured as part

Using Hydro One Distribution's approved forecasting methodology, the forecast for the period 2018 – 2022 is presented below:

Table 3: Hydro One Distribution Load and Number of Customers

Year	GWh Delivery Forecast	Distribution Customer Count
2018	36,019	1,300,516
2019	35,680	1,309,216
2020	35,673	1,317,967
2021*	36,363	1,386,522
2022*	36,373	1,395,578

* The figures include the impact of integrating Acquired Utilities into Hydro One Distribution.

The figures in Table 3 and for 2017 reflect: (a) the impact of amendments to the Distribution System Code related to the elimination of load transfer arrangements between electricity distributors (EB-2015-0006), and (b) the impact of integrating load and customer numbers of Norfolk, Haldimand and Woodstock (the "Acquired Utilities") into Hydro One Distribution. Relative to the latest forecast of 2017 figures, Hydro One forecasts a decrease of 0.6% in its load forecast and an increase of 0.7% in the customer count forecast for 2018. The small decrease in load is mainly due to the impact of conservation and demand management ("CDM") and economic factors. Relative to currently approved 2017 figures, Hydro One forecasts a decrease of 5.5% in its load forecast and a decrease of 0.8% in the customer count for 2018. Section 4 provides a more detailed discussion comparing forecasts for 2018 to 2022 with historic years 2015 to 2016 and bridge year 2017.

Table 7: Revenue Requirement ($ Millions)

Components	**2017**[1]	**2018**	**Reference**
OM&A	593.0	584.8	Exhibit C1, Tab 1, Schedule1
Depreciation and Amortization	390.2	392.6	Exhibit C1, Tab 6, Schedule 1
Income Taxes	48.7	61.5	Exhibit C1, Tab 7, Schedule 1
Return on Capital	435.8	461.1	Exhibit D1, Tab 2, Schedule 1
Total Revenue Requirement	**1,467.6**	**1,499.9**	Exhibit E2, Tab 1, Schedule 1
Deduct External Revenues and Other	(52.7)	(53.6)	Exhibit E1, Tab 1, Schedule 2
Rates Revenue Requirement	**1,414.9**	**1,446.3**	
Regulatory Deferral and Variance Accounts Disposition	11.1	6.2	Exhibit F1, Tab 2, Schedule 1, Attachment 1
Rates Revenue Requirement (with Deferral and Variance Accounts)	**1,426.0**	**1,452.4**	

Exhibit Reference: E1-1-1

Note 1: The 2017 revenue requirement is from the OEB approved Hydro One Distribution's 2015 to 2017 rate application in EB-2013-0416

The increase in revenue requirement is largely attributable to the impact of rate base growth, as reflected in the increase in depreciation, return on capital, income tax expenses and lower external revenue forecast as described in Exhibit E1, Tab 1, Schedule 2. These are partially offset by a lower cost of debt and lower OM&A costs.

5.1.1 BUDGETING ASSUMPTIONS

For 2018, Hydro One assumed 2.0% annual inflation and cost escalators for construction and OM&A expense growth of 2.5% and 2.2%, respectively. These assumptions are explained in further detail in Section 2.1.2 of the DSP. Hydro One adopted the US GAAP accounting standard for regulatory purposes, based on the OEB's Decision with Reasons in EB-2011-0268.

5.1.2 LOAD FORECAST SUMMARY

Table 8 sets out Hydro One's 2018-2022 distribution system load forecast, which includes the impact of conservation and demand management and embedded generation.

.25

Table 2: Custom Cap Index (RCI) by Component (%) + lines 13 and 14 of Table 1: Summary of Revenue Requirement Components

Custom Revenue Cap Index by Component		2018	2019	2020	2021	2022	
Inflation Factor (I)	(I)		1.90%	1.90%	1.90%	1.90%	Exhibit A/3/2/page 7 (updated 2017-06-07)
Productivity Factor (X)	(X)		0.45%	0.45%	0.45%	0.45%	
Increase in Capital Related Revenue Requirement	(CRRR)		2.84%	2.73%	3.69%	2.31%	Exhibit A/3/2/page 6 (updated 2017-06-07)
Less Capital Related Revenue Requirement in I -X			0.88%	0.90%	0.91%	0.91%	Lines 13 and 14
Capital Factor (C)	(C)		1.96%	1.83%	2.78%	1.39%	
Revenue Cap Index (RCI) = I - X + C	(RCI)		3.41%	3.28%	4.23%	2.84%	

Table 3: Revenue Requirement by Year

		2018	2019	2020	2021	2022	Exhibit A/3/2/page 8 (updated 2017-06-07)
Revenue Requirement ($M)	(RR)	1499.9	1551	1601.9	1680.4	1728.2	
Annual % change in revenue requirement	(ΔRR)		3.35%	3.23%	4.78%	2.80%	

Table 3: Hydro One Distribution Load and Number of Customers

Exhibit E1/2/1/page 5 (updated 2017-06-07)

Year		2018	2019	2020	2021	2022
GWh Delivery Forecast		36,019	35,680	35,673	36,363	36,373
Distribution Customer Count		1,300,516	1,309,216	1,317,967	1,386,522	1,395,578
Annual % change in customer count	(g)		0.67%	0.67%	5.07%	0.65%
Capital Related Revenue Requirement adjusted for customer growth	(1+CRRR)/(1+g)-1		2.16%	2.05%	-1.31%	1.65%
Capital Factor adjusted for customer growth	(1+C)/(1+g)-1		1.28%	1.16%	-2.18%	0.73%
Revenue Cap Index adjusted for customer growth	(1+RCI)/(1+g)-1		2.73%	2.60%	-0.80%	2.17%
Revenue Requirement % change adjusted for customer growth	(1+ΔRR)/(1+g)-1		2.67%	2.55%	-0.27%	2.14%