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Frank D'Andrea
Vice President
Regulatory Affairs & Chief Risk Officer

BY COURIER

November 16, 2017

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
Suite 2700, 2300 Yonge Street
P.O. Box 2319
Toronto, ON M4P 1E4

Dear Ms. Walli:

EB-2016-0160 - Hydro One Networks' 2017-2018 Transmission Revenue Requirement & Charge Determinants
EB-2017-0280 - 2017 Uniform Transmission Rates

Pursuant to the Ontario Energy Board's (the "**OEB**") November 9, 2017 Decision and Order in the above-noted proceeding (the "**DRO Decision**"), please find attached (a) updated draft revenue requirement/charge determinant order, draft UTR rate order and supporting schedules and (b) an updated explanation of how the OEB's decisions in the proceeding have been implemented.

The draft revenue requirement/charge determinant order and draft UTR order have been modified to reflect the impact of the DRO Decision. The 2017 originally proposed revenue requirement of $1,588.8 million has been further reduced to $1,539.6 million, and the 2018 proposed revenue requirement of $1,660.3 million has been reduced to $1,599.4 million. As indicated in Hydro One's letter of October 10, 2017, the 2018 proposed revenue requirement will be further updated to reflect the 2017 actual debt issuances, 2018 forecast issuances, and the OEB's applicable cost of capital parameters as part of preparing the 2018 draft order. The underlying assumptions and revenue requirement calculations have been adjusted to reflect the DRO Decision and are set out in the attached documentation.

The updated 2017 UTRs in $/kW-Month are determined to be $3.52 for Network, $0.88 for Line Connection and $2.13 for Transformation Connection. The updated calculation of the 2017 UTRs, wholesale meter rates, low voltage switchgear credit, charge determinants, revenue disbursement allocators, foregone revenue calculation, and bill impacts resulting from the OEB's findings are detailed in Exhibits 3.0 to 9.0. The revenue requirement and charge determinants used for other Ontario transmitters in calculating the 2017 UTRs reflect their current OEB-approved values and are set out in Exhibit 5.1.

By copy of this letter, we are notifying all intervenors, OEB staff and other Ontario transmitters of this filing.

Sincerely,

ORIGINAL SIGNED BY FRANK D'ANDREA

Frank D'Andrea

Encls.
cc. EB-2016-0160 parties (electronic)
EB-2017-0280 parties (electronic)

Implementation of Decision (Updated)
November 16, 2017

On September 28, 2016, the OEB released its decision on Hydro One's application for OEB approval of its proposed electricity transmission revenue requirement (EB-2016-0160). Its decision ("**Decision**") is effective as of January 1, 2017.

Hydro filed a draft revenue requirement/charge determinant order and a draft UTR rate order and supporting schedules reflecting the OEB's findings (collectively, "**Draft Order**") on October 10, 2017. Multiple submissions were made by parties on the Draft Order following which the OEB issued a Decision and Order on November 9th (the "**DRO Decision**").

In its DRO Decision, the OEB ordered an adjustment to recoverable income tax expenses and established the implementation date for new rates as November 1, 2017.

This memo explains how Hydro One has implemented the changes ordered by the OEB in its Decision and DRO Decision.

Determination of Revenue Requirement

Pursuant to the DRO Decision, Hydro One has further reduced the proposed revenue requirements from $1,588.8 to $1,539.6 million for 2017 and from $1,660.3 million to $1,599.4 million to 2018.

The derivation of the 2017 revenue requirement includes the following cumulative adjustments directed by the OEB:

- a reduction in OM&A expenses of $15.0 million to reflect the OEB's direction on compensation (Exhibit 1.1);
- the reduction of $0.5 million in working capital resulting from the lower OM&A expenses (Exhibit 1.2);
- a cumulative reduction of $3.3 million in cost of capital and depreciation expenses to reflect the impact on in-service capital additions caused by OEB-directed capital expenditure cuts (Exhibits 1.2 and 1.4); and
- a reduction of $30.9 million in income tax expenses to reflect the application of the

62% benefits follows cost allocation factor (as per the DRO Decision) to the deferred tax asset and lower return on equity.

A summary of the specific adjustments and the derivation of the updated 2017 revenue requirement is provided in Exhibit 1.0 with further details provided in subsequent Exhibits.

Capital Spending Reductions

In response to the OEB's direction to cut the 2017 and 2018 capital envelopes by $126.1 million and $122.2 million, respectively, Hydro One is deferring several capital investments resulting in an extended period of time over which customers will be exposed to risks associated with these asset needs. In some cases, mitigating actions will be required to maintain an acceptable level of performance. Hydro One is also reducing value-based investment in tower coating which do not impact system risk today, but will result in higher costs in the future.

A number of programs have been reduced or deferred from Hydro One's proposed capital plan to achieve the requested capital reduction. Given the multi-year nature of capital projects, the focus has been on deferring capital expenditure without causing significant impact to projects in a mature state of execution. For 2017, given the timing of the OEB's decision, Hydro One focused on execution risk considerations. Additional considerations were given to material and contract timing as well as budgeted contingency funding.

For 2018, Hydro One assessed the work program in two phases. Execution risk was evaluated for those multi-year projects currently in execution. Investments in the planning phase were then re-prioritized through a risk-based prioritization framework, taking customer requests into consideration. Investments with lower risk mitigation values were reduced or deferred.

Table 1 reflects Hydro One's updated forecast capital spending for the 2017-2018 period, adjusted for the Decision and more current information. (Hydro One developed the 2017-2018 capital forecast for its application in early 2016.)

Table 1: Capital Spending ($ Million)

	Test Years Evidence		Test Years Decision	
	2017	**2018**	**2017**	**2018**
Sustaining	776.8	842.1	744.7	795.4
Development	196.4	170.2	131.4	94.9
Operations	25.4	30.8	13.0	42.9
Common Corporate Cost Capital	77.6	79.1	60.9	66.8
Total	**1,076.1**	**1,122.2**	**950.0**	**1,000.0**

Attachment 2 of Hydro One's Reply Submission provides a more detailed breakdown of these forecasts.

In regards to the capital envelope, the Decision focused on Hydro One's proposed level of Sustainment capital and found that the proposed pacing of tower coating investments and stations investments was aggressive. For ease of reference, the Sustainment capital portion of Attachment 2 of the Reply Submission is reproduced as Table 2 below.

Table 2: Sustainment Capital ($ Million)

Transmission Capital ($millions)	**Test Years Evidence**		**Test Years Decision**	
	2017	**2018**	**2017**	**2018**
Sustaining Capital				
Transmission Stations				
Circuit Breakers	1.1	0	0.4	3.0
Power Transformers	0	0	1.1	0.5
Other Power Equipment	0	0	0.1	0.2
Ancillary Systems	1.3	0	1.2	0.5
Station Environment	0	0	0.2	0.0
Integrated Station Investments	457.8	404.7	469.0	397.4
Tx Transformers Demand and Spares	25.3	25.8	28.2	67.2
Protection and Automation	45.2	59.1	27.0	58.1
Site Facilities and Infrastructure	6.7	6.7	13.8	10.6
Total Transmission Stations Capital	**537.5**	**496.2**	**541.0**	**537.5**

Transmission Capital ($millions)	**Test Years Evidence**		**Test Years Decision**	
	2017	**2018**	**2017**	**2018**
Transmission Lines				
Overhead Lines Refurbishment Projects, Component Replacement Programs and Secondary Land Use Projects	237	323.4	196.5	227.8
Underground Cables Refurbishment and Replacement	2.3	22.5	7.2	30.1
Total Transmission Lines Capital	**239.3**	**345.9**	**203.7**	**257.9**
Total Sustaining Capital	**776.8**	**842.1**	**744.7**	**795.4**

Table 2 shows a deferral of Sustainment capital investments in the "Overhead Lines Refurbishment Projects, Component Replacement" component of the Transmission Lines capital portfolio, which includes the tower coating program. Specifically, after the Decision was released, Hydro One scaled the tower coating and shieldwire replacement programs back in 2017 and significantly scaled back tower coating and deferred line refurbishment projects in 2018. Hydro One was able to do so because, by its nature, program work is more scalable than project work.

In Table 2, little change is seen in the "Integrated Stations" component of the Stations capital portfolio. "Integrated Stations" investments are complex and multi-year in nature, typically taking between three and five years from conceptual design to project completion. At the time the Decision was issued, 98% and 75% of the portfolio for 2017 and 2018, respectively, was already in execution. Cancelling those projects would result in significant inefficiencies and stranded costs. Deferring the remaining 25% of the 2018 "Integrated Stations" projects would negatively impact reliability. These projects include investments at Kingsville, Leaside, Cherrywood, Sheppard, Detweiler, Minden, Gage and Stanley transformer stations. The 2017 "Integrated Stations" forecast is higher than originally stated due to the cumulative impact of a number of project-level adjustments.

As explained in the Reply Submission, reductions in the Development capital forecast were largely driven by changes in customer demand and project forecasts. The Development projects most impacted are investments at Clarington TS (-$38 million), Lisgar TS (-$7 million), Runnymede TS (-$13 million) and Hanmer TS (-$8 million).

Impact of Capital Reductions on Forecasted In-service Additions

Table 3 reflects the updated forecast for in-service additions for the 2017-2018 period.

Table 3: In-Service Capital Additions ($ Millions)

	Test Years Evidence		**Test Years Decision**	
	2017	**2018**	**2017**	**2018**
Sustaining	771.1	747.7	728.3	773.5
Development	64.6[1]	374.9	72.2[1]	308.7
Operations	8.0	10.3	4.4	9.7
Common & Other	87.8	76.8	62.9	86.5
Total	**931.4**	**1,209.7**	**867.7**	**1,178.4**

1. The proposed in-service additions under the development category in 2017 are slightly higher than previously presented due to project timing changes based on outage availability.

Hydro One's Reply Submission explains that the full impact of the 2017-2018 capital reductions were not mirrored in the revised in-service additions forecast because (a) transmission capital projects are often multi-year projects and many of these in-service additions are the result of projects initiated in earlier years, and (b) the Decision was issued just before the fourth quarter of 2017 and the cancellation of projects already well into execution is not a prudent or cost effective practice.

The Reply Submission also argued against implementing an overall capital spending to in-service ratio for the purpose of setting rates, particularly one more suited to distribution capital programs, not capital projects, as suggested by some intervenors. For context, over 70% of the 2017-2018 capital plan is comprised of projects, not programs.

Figure 1 indicates when Hydro One expected the capital investments for 2017 and 2018 as proposed in the application would be put into service. It reflects capital spending in-service addition ratios of 1:0.37 in 2017 and 1:0.46 in 2018.

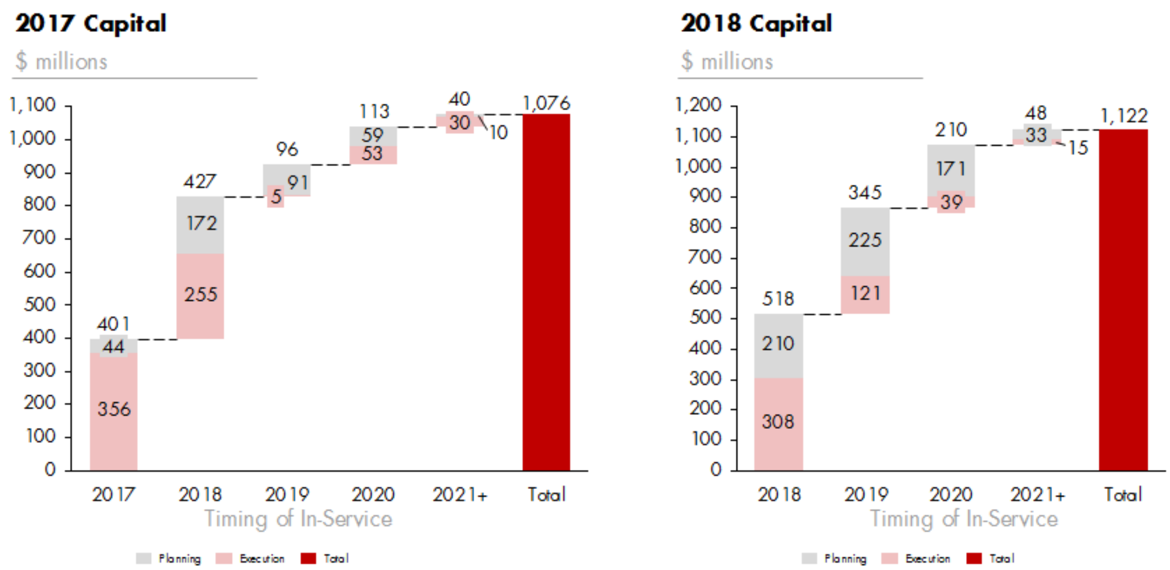

Figure 1: 2017-2018 Capital Investments as Proposed in Application

Figure 2 indicates when Hydro One anticipates the capital investments for 2017 and 2018 will be put into service, after adjusting for the Decision. This reflects a capital spending in-service addition ratios of 1:0.37 in 2017 and 1:0.48 in 2018, which are not materially different than the original ratios.

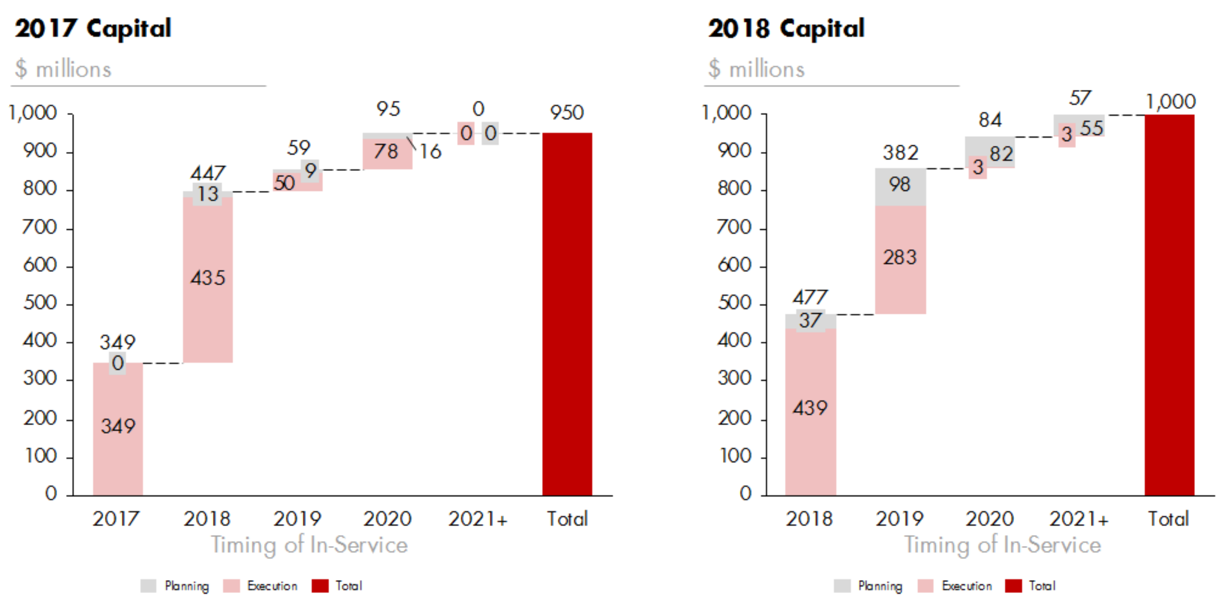

Figure 2: 2017-2018 Capital Investments Adjusted for Decision

As per the original Decision and the DRO Decision, in its next transmission rate application, Hydro One will file a report detailing how it managed its capital plan to align with the Decision and the resulting impact on in-service additions.

Foregone Transmission Revenue Deferral Account

In the DRO Decision, the OEB declared Hydro One's existing rates interim until the implementation of new rates on November 1, 2017, but effective as of January 1, 2017.

In the Decision (as subsequently adjusted by the DRO Decision), the OEB approved the recovery of foregone revenue for the period between the January 1, 2017 effective date of the 2017 rates and the November 1, 2017 implementation date of the new rates. The determination of foregone revenue in the updated amount of -$10.6 million is provided in Exhibit 9.0.

The foregone revenue amount is calculated on a monthly basis using the monthly charge determinants for each UTR rate pool consistent with the annual charge determinants approved by the OEB in the Decision. The monthly foregone revenue amount is the difference between the Hydro One share of (a) the revenue collected under the approved 2016 UTR multiplied by the approved 2017 charge determinants and (b) the revenue collected under the proposed 2017 UTR (as per Exhibit 5.0) multiplied by the approved 2017 charge determinants. The total foregone revenue for January to October, inclusive, is -$10.6 million.

The foregone revenue amount will be included the Foregone Transmission Revenue Deferral Account, as approved by the OEB. Hydro One proposes that the foregone revenue amount be included as part of Hydro One's 2018 rates revenue requirement in the determination of 2018 UTRs.

Supporting Material

The detailed information supporting the determination of the revenue requirement and charge determinants as well as the OEB-directed calculations pertaining to the deferred tax components and grossed up regulatory taxes are provided in the attached Exhibits.

EXHIBIT		TITLE
1.0	**2017 and 2018 Revenue Requirement Summary**	
	1.1	OM&A Details
	1.2	Rate Base and Depreciation Details
	1.3	Capital Expenditures and In-Service Details
	1.4	Capital Structure and Return on Capital
	1.4.1	Cost of Long-term Debt Test Year (2017 - 2018)
	1.5	Income Tax
	1.6	External Revenue
	1.7	Export Transmission Service Revenue
	1.8	Deferral and Variance Accounts
3.0	**2017 Revenue Requirement by Rate Pool**	
4.0	**2017 Charge Determinants**	
5.0	**2017 UTR Rate Order - Transmission Rates and Revenue Disbursement Allocators**	
	5.1	2017 UTR Rate Order - Revenue Requirement and Charge Determinant Assumptions for Other Transmitters
	5.2	2017 UTR Rate Order - Ontario Uniform Transmission Rate Schedules
6.0	**2017 Wholesale Meter Service and Exit Fee Schedule**	
7.0	**2017 Low Voltage Switchgear (LVSG) Credit Calculation**	
8.0	**2017 Bill Impacts**	
9.0	**2017 Foregone Revenue Calculation**	

Hydro One Networks Inc.

Implementation of Decision with Reasons on EB-2016-0160

Revenue Requirement Summary

($ millions)	**Supporting Reference**	**Hearing Update 2017**	**Hearing Update 2018**	**OEB Decision 2017**	**OEB Decision 2018**	**OEB Approved 2017**	**OEB Approved 2018**
				Note 1	Note 1		
OM&A	Exhibit 1.1	412.7	409.3	(15.0)	(15.0)	397.7	394.3
Depreciation	Exhibit 1.2	435.7	470.7	(1.3)	(2.1)	434.4	468.6
Return on Debt	Exhibit 1.4	287.8	296.4	(0.9)	(6.5)	287.0	289.9
Return on Equity	Exhibit 1.4	370.7	394.2	(1.1)	(2.7)	369.6	391.5
Income Tax (Note 2)	Exhibit 1.5	81.9	89.6	(30.9)	(34.5)	51.0	55.1
Base Revenue Requirement		**1,588.8**	**1,660.3**	**(49.2)**	**(60.9)**	**1,539.6**	**1,599.4**
Deduct: External Revenue	Exhibit 1.6	(28.2)	(28.5)	-	-	(28.2)	(28.5)
Subtotal		**1,560.6**	**1,631.8**	**(49.2)**	**(60.9)**	**1,511.4**	**1,570.9**
Deduct: Export Tx Service Revenue	Exhibit 1.7	(39.2)	(40.1)	-	-	(39.2)	(40.1)
Deduct: Other Cost Charges	Exhibit 1.8	(47.8)	(47.8)	-	-	(47.8)	(47.8)
Add: Low Voltage Switch Gear		13.8	14.5	(0.4)	(0.6)	13.4	13.9
Rates Revenue Requirement		**1,487.4**	**1,558.4**	**(49.6)**	**(61.4)**	**1,437.8**	**1,497.0**

Note 1: As per EB-2016-0160 Decision and Order on September 28, 2017.

Note 2: OEB approved Income Tax based on 62% allocation factor, 2018 calculated number is $55.1M

Hydro One Networks Inc.

Implementation of Decision with Reasons on EB-2016-0160

OM&A

($ millions)	**Supporting Reference**	**Hearing Update 2017**	**Hearing Update 2018**	**OEB Decision 2017**	**OEB Decision 2018**	**OEB Approved 2017**	**OEB Approved 2018**
				Note 1	Note 1		
OM&A	*See supporting details below*	412.7	409.3	(15.0)	(15.0)	397.7	394.3

OEB Decision Impact Supporting Details

Adjustments	**Reference**	**2017 OM&A Impacts**	**2018 OM&A Impacts**
OEB Decision	Page 58	(15.0)	(15.0)
Total OM&A impacts		(15.0)	(15.0)

Note 1: As per EB-2016-0160 Decision and Order on September 28, 2017.

Hydro One Networks Inc.
Implementation of Decision with Reasons on EB-2016-0160

Rate Base and Depreciation

($ millions)	**Supporting Reference**	**Hearing Update 2017**	**Hearing Update 2018**	**OEB Decision 2017**	**OEB Decision 2018**	**OEB Approved 2017**	**OEB Approved 2018**
				Note 1	Note 1		
Rate Base	*See supporting details below*	10,554.4	11,225.5	(31.7)	(77.5)	10,522.7	11,148.0
Depreciation	*See supporting details below*	435.7	470.7	(1.3)	(2.1)	434.4	468.6

OEB Decision Impact Supporting Details	**Reference**	**2017 Detailed Calculation**	**2018 Detailed Calculation**	**2017 Rate Base Impact**	**2018 Rate Base Impact**	**2017 Depreciation Impact**	**2018 Depreciation Impact**
Working Capital Adjustment							
Rate Base Details	Pre-filed Evidence						
Utility plant (average)	Exh D1-1-1						
Gross plant at cost		16,641.1	17,616.4				
Less: Accumulated depreciation		(6,113.4)	(6,418.7)				
Add: CWIP		-	-				
Net utility plant		10,527.8	11,197.7				
Working capital							
Cash working capital		14.7	15.6				
Materials & supplies inventory		12.0	12.2				
Total working capital		26.6	27.8				
Total Rate Base		10,554.4	11,225.5				
Working capital as % of OM&A	(a)	3.6%	3.8%				
OM&A Reduction	Exhibit 1.1 (b)	(15.0)	(15.0)				
Working capital reduction	(c) = (a) x (b)	(0.5)	(0.6)	(0.5)	(0.6)		

RATE BASE IMPACT OF CAPITAL / IN-SERVICE ADJUSTMENTS	**2017 Decision**	**2018 Decision**
In-service impacts	(63.7)	(31.3)
Depreciation impacts	(1.3)	(2.1)

Note 1: As per EB-2016-0160 Decision and Order on September 28, 2017.

Hydro One Networks Inc.
Implementation of Decision with Reasons on EB-2016-0160

Capital Expenditures and In-Service

($ millions)	**Supporting Reference**	**Hearing Update 2017**	**Hearing Update 2018**	**OEB Decision 2017**	**OEB Decision 2018**	**OEB Approved 2017**	**OEB Approved 2018**
				Note 1	Note 1		
Capital expenditures	*See supporting details below*	1,076.1	1,122.2	(126.1)	(122.2)	950.0	1,000.0

OEB Decision Impact Supporting Details

Adjustments	**Reference**	**2017 Capex OEB Decision**	**2018 Capex OEB Decision**
Capex adjustments	Page 29	(126.1)	(122.2)
Total capital adjustments in OEB decision		(126.1)	(122.2)
In-service adjustments	Page 29	(63.7)	(31.3)
Total in-service adjustments in OEB decision		(63.7)	(31.3)

Note 1: As per EB-2016-0160 Decision and Order on September 28, 2017.

Hydro One Networks Inc.

Implementation of Decision with Reasons on EB-2016-0160

Capital Structure and Return on Capital

($ millions)	**Supporting Reference**	**Hearing Update 2017**	**Hearing Update 2018**	**OEB Decision 2017**	**OEB Decision 2018**	**OEB Approved 2017**	**OEB Approved 2018**
Return on Rate Base							Note 2
Rate Base	Exhibit 1.2	$ 10,554.4	$ 11,225.5	$ (31.7)	$ (77.5)	$ 10,522.7	$ 11,148.0
Capital Structure:							
Third-Party long-term debt		56.00%	56.00%	-1.36%	-1.05%	54.64%	54.95%
Deemed long-term debt		0.00%	0.00%	1.36%	1.05%	1.36%	1.05%
Short-term debt		4.00%	4.00%	0.00%	0.00%	4.00%	4.00%
Common equity		40.00%	40.00%	0.00%	0.00%	40.00%	40.00%
Capital Structure:							
Third-Party long-term debt	Exhibit 1.4.1 and 1.4.2	5,910.4	6,286.3	(160.9)	(160.9)	5,749.5	6,125.4
Deemed long-term debt		0.0	0.0	143.1	117.5	143.2	117.5
Short-term debt		422.2	449.0	(1.3)	(3.1)	420.9	445.9
Common equity		4,221.7	4,490.2	(12.7)	(31.0)	4,209.1	4,459.2
		10,554.4	**11,225.5**	**(31.7)**	**(77.5)**	**10,522.7**	**11,148.0**
Allowed Return:							
Third-Party long-term debt	Exhibit 1.4.1 & 1.4.2	4.67%	4.52%	0.00%	0.00%	4.67%	4.52%
Deemed long-term debt	Exhibit 1.4.1 & 1.4.2	4.67%	4.52%	0.00%	0.00%	4.67%	4.52%
Short-term debt		1.76%	1.76%	0.00%	0.00%	1.76%	1.76%
Common equity		8.78%	8.78%	0.00%	0.00%	8.78%	8.78%
Return on Capital:							
Third-Party long-term debt		275.8	284.1	(7.5)	(7.3)	268.3	276.8
Deemed long-term debt		0.0	0.0	6.7	5.3	6.7	5.3
Short-term debt		7.4	7.9	(0.0)	(0.1)	7.4	7.8
AFUDC return on Niagara Reinforcement Proje	see below	4.6	4.5	-	(4.5)	4.6	-
Total return on debt		**$ 287.8**	**$ 296.4**	**$ (0.9)**	**$ (6.5)**	**$ 287.0**	**$ 289.9**
Common equity		**$ 370.7**	**$ 394.2**	**$ (1.1)**	**$ (2.7)**	**$ 369.6**	**$ 391.5**
AFUDC return on Niagara Reinforcement Project							
CWIP	Note 1	99.1	99.1			99.1	
Deemed long-term debt		4.67%	4.52%			4.67%	
		4.6	4.5			4.6	

Note 1: As per EB-2016-0160 Decision and Order on September 28, 2017.

HYDRO ONE NETWORKS INC.
TRANSMISSION
Cost of Long-Term Debt Capital
Test Year (2017)
Year ending December 31

Line No.	Offering Date	Coupon Rate	Maturity Date	Principal Amount Offered ($Millions)	Premium Discount and Expenses ($Millions)	Net Capital Employed: Total Amount ($Millions)	Net Capital Employed: Per $100 Principal Amount (Dollars)	Effective Cost Rate	Total Amount Outstanding at 12/31/2016 ($Millions)	Total Amount Outstanding at 12/31/2017 ($Millions)	Avg. Monthly Averages ($Millions)	Carrying Cost ($Millions)	Projected Average Embedded Cost Rates
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
1	3-Jun-00	7.350%	3-Jun-30	278.4	4.5	273.9	98.4	7.49%	278.4	278.4	278.4	20.8	
2	22-Jun-01	6.930%	1-Jun-32	109.3	1.3	107.9	98.8	7.03%	109.3	109.3	109.3	7.7	
3	17-Sep-02	6.930%	1-Jun-32	58.0	(2.1)	60.1	103.6	6.65%	58.0	58.0	58.0	3.9	
4	31-Jan-03	6.350%	31-Jan-34	126.0	1.0	125.0	99.2	6.41%	126.0	126.0	126.0	8.1	
5	22-Apr-03	6.590%	22-Apr-43	145.0	1.1	143.9	99.3	6.64%	145.0	145.0	145.0	9.6	
6	25-Jun-04	6.350%	31-Jan-34	72.0	(0.2)	72.2	100.2	6.33%	72.0	72.0	72.0	4.6	
7	20-Aug-04	6.590%	22-Apr-43	39.0	(3.1)	42.1	107.9	6.06%	39.0	39.0	39.0	2.4	
8	24-Aug-04	6.350%	31-Jan-34	39.0	(1.4)	40.4	103.5	6.09%	39.0	39.0	39.0	2.4	
9	19-May-05	5.360%	20-May-36	228.9	8.7	220.2	96.2	5.62%	228.9	228.9	228.9	12.9	
10	24-Apr-06	5.360%	20-May-36	187.5	2.5	185.0	98.7	5.45%	187.5	187.5	187.5	10.2	
11	19-Oct-06	5.000%	19-Oct-46	30.0	0.2	29.8	99.3	5.04%	30.0	30.0	30.0	1.5	
12	13-Mar-07	4.890%	13-Mar-37	240.0	1.3	238.7	99.4	4.93%	240.0	240.0	240.0	11.8	
13	18-Oct-07	5.180%	18-Oct-17	225.0	0.8	224.2	99.6	5.23%	225.0	0.0	173.1	9.0	
14	3-Mar-08	5.180%	18-Oct-17	180.0	(3.1)	183.1	101.7	4.95%	180.0	0.0	138.5	6.9	
15	3-Mar-09	6.030%	3-Mar-39	195.0	1.2	193.8	99.4	6.07%	195.0	195.0	195.0	11.8	
16	16-Jul-09	5.490%	16-Jul-40	210.0	1.4	208.6	99.4	5.53%	210.0	210.0	210.0	11.6	
17	15-Mar-10	5.490%	24-Jul-40	120.0	(0.7)	120.7	100.6	5.45%	120.0	120.0	120.0	6.5	
18	15-Mar-10	4.400%	4-Jun-20	180.0	0.8	179.2	99.5	4.46%	180.0	180.0	180.0	8.0	
19	13-Sep-10	5.000%	19-Oct-46	150.0	(0.4)	150.4	100.2	4.98%	150.0	150.0	150.0	7.5	
20	26-Sep-11	4.390%	26-Sep-41	205.0	1.3	203.7	99.3	4.43%	205.0	205.0	205.0	9.1	
21	22-Dec-11	4.000%	22-Dec-51	70.0	0.4	69.6	99.5	4.03%	70.0	70.0	70.0	2.8	
22	13-Jan-12	3.200%	13-Jan-22	154.0	0.8	153.2	99.5	3.26%	154.0	154.0	154.0	5.0	
23	22-May-12	3.200%	13-Jan-22	165.0	(1.6)	166.6	101.0	3.08%	165.0	165.0	165.0	5.1	
24	22-May-12	4.000%	22-Dec-51	68.8	0.3	68.4	99.5	4.02%	68.8	68.8	68.8	2.8	
25	31-Jul-12	3.790%	31-Jul-62	52.5	0.3	52.2	99.5	3.81%	52.5	52.5	52.5	2.0	
26	16-Aug-12	3.790%	31-Jul-62	141.0	1.1	139.9	99.2	3.83%	141.0	141.0	141.0	5.4	
27	9-Oct-13	4.590%	9-Oct-43	239.3	1.4	237.9	99.4	4.63%	239.3	239.3	239.3	11.1	
28	9-Oct-13	2.780%	9-Oct-18	412.5	1.7	410.8	99.6	2.87%	412.5	412.5	412.5	11.8	
29	29-Jan-14	4.290%	29-Jan-64	30.0	0.2	29.8	99.4	4.32%	30.0	30.0	30.0	1.3	
30	3-Jun-14	4.170%	3-Jun-44	198.0	1.2	196.8	99.4	4.21%	198.0	198.0	198.0	8.3	
31	24-Feb-16	3.910%	23-Feb-46	175.0	1.1	173.9	99.4	3.95%	175.0	175.0	175.0	6.9	
32	24-Feb-16	2.770%	24-Feb-26	245.0	1.1	243.9	99.6	2.82%	245.0	245.0	245.0	6.9	
33	24-Feb-16	1.840%	24-Feb-21	250.0	0.9	249.1	99.6	1.92%	250.0	250.0	250.0	4.8	
34	18-Nov-16	3.720%	18-Nov-47	270.0	1.4	268.7	99.5	3.75%	270.0	270.0	270.0	10.1	
35	15-Mar-17	3.670%	15-Mar-47	219.1	1.1	218.0	99.5	3.70%	0.0	219.1	168.5	6.2	
36	15-Jun-17	2.606%	15-Jun-27	109.6	0.5	109.0	99.5	2.66%	0.0	109.6	59.0	1.6	
37	15-Jun-17	3.670%	15-Jun-47	109.6	0.5	109.0	99.5	3.70%	0.0	109.6	59.0	2.2	
38	15-Sep-17	2.606%	15-Sep-27	219.1	1.1	218.0	99.5	2.66%	0.0	219.1	67.4	1.8	
39		**Subtotal**							5489.1	5741.4	5749.5	262.4	
40		Treasury OM&A costs										1.8	
41		Other financing-related fees										4.1	
42		**Total**							5489.1	5741.4	5749.5	268.3	4.67%

HYDRO ONE NETWORKS INC.

TRANSMISSION

Cost of Long-Term Debt Capital

Test Year (2018)

Year ending December 31

Line No.	Offering Date	Coupon Rate	Maturity Date	Principal Amount Offered ($Millions)	Premium Discount and Expenses ($Millions)	Net Capital Employed: Total Amount ($Millions)	Net Capital Employed: Per $100 Principal Amount (Dollars)	Effective Cost Rate	Total Amount Outstanding: at 12/31/2017 ($Millions)	Total Amount Outstanding: at 12/31/2018 ($Millions)	Avg. Monthly Averages ($Millions)	Carrying Cost ($Millions)	Projected Average Embedded Cost Rates
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
1	3-Jun-00	7.350%	3-Jun-30	278.4	4.5	273.9	98.37	7.49%	278.4	278.4	278.4	20.8	
2	22-Jun-01	6.930%	1-Jun-32	109.3	1.3	107.9	98.78	7.03%	109.3	109.3	109.3	7.7	
3	17-Sep-02	6.930%	1-Jun-32	58.0	(2.1)	60.1	103.57	6.65%	58.0	58.0	58.0	3.9	
4	31-Jan-03	6.350%	31-Jan-34	126.0	1.0	125.0	99.21	6.41%	126.0	126.0	126.0	8.1	
5	22-Apr-03	6.590%	22-Apr-43	145.0	1.1	143.9	99.26	6.64%	145.0	145.0	145.0	9.6	
6	25-Jun-04	6.350%	31-Jan-34	72.0	(0.2)	72.2	100.22	6.33%	72.0	72.0	72.0	4.6	
7	20-Aug-04	6.590%	22-Apr-43	39.0	(3.1)	42.1	107.89	6.06%	39.0	39.0	39.0	2.4	
8	24-Aug-04	6.350%	31-Jan-34	39.0	(1.4)	40.4	103.48	6.09%	39.0	39.0	39.0	2.4	
9	19-May-05	5.360%	20-May-36	228.9	8.7	220.2	96.19	5.62%	228.9	228.9	228.9	12.9	
10	24-Apr-06	5.360%	20-May-36	187.5	2.5	185.0	98.68	5.45%	187.5	187.5	187.5	10.2	
11	19-Oct-06	5.000%	19-Oct-46	30.0	0.2	29.8	99.29	5.04%	30.0	30.0	30.0	1.5	
12	13-Mar-07	4.890%	13-Mar-37	240.0	1.3	238.7	99.45	4.93%	240.0	240.0	240.0	11.8	
13	3-Mar-09	6.030%	3-Mar-39	195.0	1.2	193.8	99.41	6.07%	195.0	195.0	195.0	11.8	
14	16-Jul-09	5.490%	16-Jul-40	210.0	1.4	208.6	99.36	5.53%	210.0	210.0	210.0	11.6	
15	15-Mar-10	5.490%	24-Jul-40	120.0	(0.7)	120.7	100.58	5.45%	120.0	120.0	120.0	6.5	
16	15-Mar-10	4.400%	4-Jun-20	180.0	0.8	179.2	99.55	4.46%	180.0	180.0	180.0	8.0	
17	13-Sep-10	5.000%	19-Oct-46	150.0	(0.4)	150.4	100.25	4.98%	150.0	150.0	150.0	7.5	
18	26-Sep-11	4.390%	26-Sep-41	205.0	1.3	203.7	99.35	4.43%	205.0	205.0	205.0	9.1	
19	22-Dec-11	4.000%	22-Dec-51	70.0	0.4	69.6	99.47	4.03%	70.0	70.0	70.0	2.8	
20	13-Jan-12	3.200%	13-Jan-22	154.0	0.8	153.2	99.47	3.26%	154.0	154.0	154.0	5.0	
21	22-May-12	3.200%	13-Jan-22	165.0	(1.6)	166.6	100.97	3.08%	165.0	165.0	165.0	5.1	
22	22-May-12	4.000%	22-Dec-51	68.8	0.3	68.4	99.51	4.02%	68.8	68.8	68.8	2.8	
23	31-Jul-12	3.790%	31-Jul-62	52.5	0.3	52.2	99.47	3.81%	52.5	52.5	52.5	2.0	
24	16-Aug-12	3.790%	31-Jul-62	141.0	1.1	139.9	99.20	3.83%	141.0	141.0	141.0	5.4	
25	9-Oct-13	4.590%	9-Oct-43	239.3	1.4	237.9	99.42	4.63%	239.3	239.3	239.3	11.1	
26	9-Oct-13	2.780%	9-Oct-18	412.5	1.7	410.8	99.59	2.87%	412.5	0.0	317.3	9.1	
27	29-Jan-14	4.290%	29-Jan-64	30.0	0.2	29.8	99.44	4.32%	30.0	30.0	30.0	1.3	
28	3-Jun-14	4.170%	3-Jun-44	198.0	1.2	196.8	99.40	4.21%	198.0	198.0	198.0	8.3	
29	24-Feb-16	3.910%	23-Feb-46	175.0	1.1	173.9	99.4	3.95%	175.0	175.0	175.0	6.9	
30	24-Feb-16	2.770%	24-Feb-26	245.0	1.1	243.9	99.6	2.82%	245.0	245.0	245.0	6.9	
31	24-Feb-16	1.840%	24-Feb-21	250.0	0.9	249.1	99.6	1.92%	250.0	250.0	250.0	4.8	
32	18-Nov-16	3.720%	18-Nov-47	270.0	1.4	268.7	99.5	3.75%	270.0	270.0	270.0	10.1	
33	15-Mar-17	3.670%	15-Mar-47	219.1	1.1	218.0	99.5	3.70%	219.1	219.1	219.1	8.1	
34	15-Jun-17	2.606%	15-Jun-27	109.6	0.5	109.0	99.5	2.66%	109.6	109.6	109.6	2.9	
35	15-Jun-17	3.670%	15-Jun-47	109.6	0.5	109.0	99.5	3.70%	109.6	109.6	109.6	4.1	
36	15-Sep-17	2.606%	15-Sep-27	219.1	1.1	218.0	99.5	2.66%	219.1	219.1	219.1	5.8	
37	15-Mar-18	4.370%	15-Mar-48	296.6	1.5	295.2	99.50	4.40%	0.0	296.6	228.2	10.0	
38	15-Jun-18	3.306%	15-Jun-28	296.6	1.5	295.2	99.50	3.37%	0.0	296.6	159.7	5.4	
39	15-Sep-18	2.545%	15-Sep-23	296.6	1.5	295.2	99.50	2.65%	0.0	296.6	91.3	2.4	
40		**Subtotal**							5741.4	6218.8	6125.4	270.7	
41		Treasury OM&A costs										2.0	
42		Other financing-related fees										4.1	
43		**Total**							5741.4	6218.8	6125.4	276.8	4.52%

Hydro One Networks Inc.
Implementation of Decision with Reasons on EB-2016-0160

Income Tax

($ millions)	Supporting Reference	Hearing Update 2017	Hearing Update 2018	OEB Decision Impact 2017	OEB Decision Impact 2018	OEB Approved 2017	OEB Approved 2018
Income Taxes	*See supporting details below*	81.9	89.6	(30.9)	(34.5)	51.0	55.1

Income Tax Supporting Details			Hydro One Proposed 2017	Hydro One Proposed 2018	OEB Decision Impact 2017	OEB Decision Impact 2018	OEB Approved 2017	OEB Approved 2018
Rate Base	Exhibit 1.2	a	$ 10,554.4	$ 11,225.5	$ (31.7)	$ (77.5)	$ 10,522.7	$ 11,148.0
Common Equity Capital Structure		b	40.0%	40.0%			40.0%	40.0%
Return on Equity	Exhibit 1.4	c	8.78%	8.78%	0.00%	0.00%	8.78%	8.78%
Return on Equity		d = a x b x c	370.7	394.2	(1.1)	(2.7)	369.6	391.5
Regulatory Income Tax		e = l	81.9	89.6	0.3	(0.8)	82.2	88.8
Regulatory Net Income (before tax)		f = d + e	452.6	483.8	(0.8)	(3.5)	451.8	480.3
Timing Differences *(Note 1)*		g	(140.3)	(142.6)	2.0	0.5	(138.3)	(142.1)
Taxable Income		h = f + g	312.2	341.2	1.3	(3.0)	313.5	338.2
Tax Rate		i	26.5%	26.5%			26.5%	26.5%
Income Tax		j = h x i	82.7	90.4	0.3	(0.8)	83.1	89.6
less: Income Tax Credits		k	(0.8)	(0.8)	-	-	(0.8)	(0.8)
Regulatory Income Tax		l = j + k	81.9	89.6	0.3	(0.8)	82.2	88.8
less: Deferred Tax Asset Sharing *[Note 2]*		m	-	-	(31.2)	(33.7)	(31.2)	(33.7)
Income Taxes		n = l + m	81.90	89.60	(30.9)	(34.5)	51.0	55.1

Note 1. Book to Tax Timing Differences	Hydro One Proposed 2017	Hydro One Proposed 2018	OEB Decision Impact 2017	OEB Decision Impact 2018	OEB Approved 2017	OEB Approved 2018
Depreciation	435.7	470.7	(1.3)	(2.1)	434.4	468.6
CCA	(516.0)	(547.9)	3.4	2.6	(512.7)	(545.4)
Other Timing Differences	(60.0)	(65.4)	-	-	(60.0)	(65.4)
Total Timing Differences	(140.3)	(142.6)	2.0	0.5	(138.3)	(142.1)

Note 2: As per EB-2016-0160 Decision and Order on September 28, 2017.

	2017	2018
Income Tax from OEB Decision (Pre-DTA Sharing)	82.2	88.8
Deferred Tax Asset Sharing	31.2	33.7

Hydro One Networks Inc.

Implementation of Decision with Reasons on EB-2016-0160

External Revenue

($ millions)	**Supporting Reference**	**Hearing Update 2017**	**Hearing Update 2018**	**OEB Decision 2017**	**OEB Decision 2018**	**OEB Approved 2017**	**OEB Approved 2018**
External Revenue	*See supporting details below*	28.2	28.5	-	-	28.2	28.5

External Revenue Details E1-2-1 Page 2	Hydro One Proposed 2017	Hydro One Proposed 2018	OEB Decision Impact 2017	OEB Decision Impact 2018	OEB Approved 2017	OEB Approved 2018
Secondary Land Use	15.4	15.6	-	-	15.4	15.6
Station Maintenance	5.3	5.3	-	-	5.3	5.3
Engineering & Construction	-	-	-	-	-	-
Other	7.5	7.6	-	-	7.5	7.6
Total	28.2	28.5	-	-	28.2	28.5

Hydro One Networks Inc.

Implementation of Decision with Reasons on EB-2016-0160

Export Transmission Service Revenue

($ millions)	Supporting Reference	Hearing Update 2017	Hearing Update 2018	OEB Decision 2017	OEB Decision 2018	OEB Approved 2017	OEB Approved 2018
Export Transmission Service Revenue		(39.2)	(40.1)			(39.2)	(40.1)

Hydro One Networks Inc.
Implementation of Decision with Reasons on EB-2016-0160

Deferral and Variance Accounts

($ millions)	**Supporting Reference**	**Hearing Update 2017**	**Hearing Update 2018**	**OEB Decision 2017**	**OEB Decision 2018**	**OEB Approved 2017**	**OEB Approved 2018**
Deferral and Variance Accounts	*See supporting details below*	(47.8)	(47.8)	-	-	(47.8)	(47.8)

Deferral and Variance Accounts Details F1-1-3	Hydro One Proposed 2017	Hydro One Proposed 2018	OEB Decision Impact 2017	OEB Decision Impact 2018	OEB Approved 2017	OEB Approved 2018
Rights Payments	(1.5)	(1.5)			(1.5)	(1.5)
Tax Rate Changes Account	0.1	0.1			0.1	0.1
B2M	(0.5)	(0.5)			(0.5)	(0.5)
Tx CDM	(27.0)	(27.0)			(27.0)	(27.0)
Reg Asset - LT Tx Future Corridor Acq & Dev Act	0.3	0.3			0.3	0.3
Deferred Pension OM&A	3.0	3.0			3.0	3.0
External Revenues	(13.0)	(13.0)			(13.0)	(13.0)
Tx Excess Export Deferred Revenue	(9.2)	(9.2)			(9.2)	(9.2)
Total	(47.8)	(47.8)	-	-	(47.8)	(47.8)

Hydro One Networks Inc.

Implementation of Decision with Reasons on EB-2016-0160

2017 Revenue Requirement by Rate Pool

		2017 Rate Pool Revenue Requirement ($ Million)			
	Supporting Exhibit	**Network (Note 3)**	**Line Connection**	**Transformation Connection**	**Uniform Transmission Rates Revenue Requirement**
OM&A	*1.1*	196.1	39.6	98.4	334.1
Other Taxes (Grants-in-Lieu)	*Note 1*	37.6	9.4	16.6	63.6
Depreciation of Fixed Assets	*1.2*	217.9	52.8	110.6	381.3
Capitalized Depreciation	*Note 2*	(7.1)	(1.8)	(3.2)	(12.1)
Asset Removal Costs	*Note 2*	31.4	8.0	14.0	53.4
Other Amortization	*Note 2*	7.0	1.7	3.1	11.8
Return on Debt	*1.4*	169.8	42.4	74.8	287.0
Return on Equity	*1.4*	218.7	54.5	96.3	369.5
Income Tax	*1.5*	30.2	7.5	13.3	51.0
Base Revenue Requirement		**901.5**	**214.2**	**423.9**	**1539.6**
Less External Revenues	*1.6*	(16.5)	(3.9)	(7.8)	(28.2)
Total Revenue Requirement		**885.0**	**210.2**	**416.1**	**1511.4**
Less MSP Revenue	*Note 3*			(0.3)	(0.3)
Less Export Revenues	*1.7*	(39.2)			(39.2)
Less Regulatory Asset Credit	*1.8*	(31.8)	(5.4)	(10.6)	(47.8)
Plus LVSG Credit	*8.0*			13.4	13.4
Total Rates Revenue Requirement*	*Note 3*	**814.0**	**204.9**	**418.5**	**1437.5**

Note 1: Included in OEB Approved 2017 OMA total in Exhibit 1.1.

Note 2: Included in OEB Approved 2017 Depreciation total in Exhibit 1.2.

Note 3: MSP revenue as per Exhibit H1, Tab 3, Schedule 1, Table 1, and assignment to Transformation Connection rate pool as per EB-2016-0160 Decision and Order, pg. 70.

Hydro One Networks Inc.

Implementation of Decision with Reasons on EB-2016-0160

Summary Charge Determinants

(for Setting Uniform Transmission Rates effective January 1, 2017 to December 31, 2017)

	2017 Total MW (Note 1)
Network	244,866
Line Connection	236,891
Transformation Connection	202,461

Note 1: The sum of 12 monthly charge determinants, consistent with Exhibit E1, Tab 3, Schedule 1, Table 1.

Hydro One Networks Inc.

Implementation of Decision with Reasons on EB-2016-0160

Uniform Transmission Rates and Revenue Disbursement Allocators
(Effective for Period January 1, 2017 to December 31, 2017)
(Implementation for November1, 2017)

Transmitter	**Revenue Requirement ($)**			
	Network	**Line Connection**	**Transformation Connection**	**Total**
FNEI	$3,583,020	$901,798	$1,842,271	$6,327,089
CNPI	$2,631,703	$662,364	$1,353,135	$4,647,201
H1N SSM	$22,972,424.93	$5,781,848	$11,811,663	$40,565,936
H1N	$814,028,889	$204,880,025	$418,546,815	$1,437,455,729
B2MLP	$33,700,000	$0	$0	$33,700,000
All Transmitters	$876,916,037	$212,226,034	$433,553,884	$1,522,695,955

Transmitter	**Total Annual Charge Determinants (MW)**			
	Network	**Line Connection**	**Transformation Connection**	
FNEI	187.120	213.460	76.190	
CNPI	522.894	549.258	549.258	
H1N SSM	3,498.236	2,734.624	635.252	
H1N	244,865.656	236,890.824	202,461.050	
B2MLP	0.000	0.000	0.000	
All Transmitters	249,073.906	240,388.166	203,721.750	

Transmitter	**Uniform Rates and Revenue Allocators**			
	Network	**Line Connection**	**Transformation Connection**	
Uniform Transmission Rates ($/kW-Month)	**3.52**	**0.88**	**2.13**	
FNEI Allocation Factor	**0.00409**	**0.00425**	**0.00425**	
CNPI Allocation Factor	**0.00300**	**0.00312**	**0.00312**	
H1N SSM Allocation Factor	**0.02620**	**0.02724**	**0.02724**	
H1N Allocation Factor	**0.92828**	**0.96539**	**0.96539**	
B2MLP Allocation Factor	**0.03843**	**0.00000**	**0.00000**	
Total of Allocation Factors	1.00000	1.00000	1.00000	

Note 1: FNEI Rates Revenue Requirement and Charge Determinants per Board Decision and Order on EB-2009-0387 dated December 9, 2010. Set as Interim on December 29, 2015 under EB-2015-0368.

Note 2: CNPI Rates Revenue Requirement and Charge Determinants per OEB Decision EB-2014-0204 dated June 25, 2015.

Note 3: H1N SSM 2017 Rates Revenue Requirement and Charge Determinants per OEB Decision EB-2016-0356, issued September 28, 2017.

Note 4: H1N Rates Revenue Requirement and Charge Determinants per OEB Decision EB-2016-0160, issued September 28, 2017 and November 9, 2017.

Note 5: B2M LP 2017 Revenue Requirement per Board Decision and Order EB-2016-0349 dated June 29, 2017.

Note 6: Calculated data in shaded cells.

Hydro One Networks Inc.

Implementation of Decision with Reasons on EB-2016-0160

2017 Revenue Requirement and Charge Determinant Assumptions for Other Transmitters

Table 1
Approved Annual Revenue Requirement and Charge Determinants

Transmitter	Annual Revenue Requirement ($)	Annual Charge Determinants (MW)			Approval Reference
		Network	Line Connection	Transformation Connection	
Five Nations Energy Inc. (FNEI)	$6,327,089	187.120	213.460	76.190	*Note 1*
Canadian Niagara Power Inc. (CNPI)	$4,647,201	522.894	549.258	549.258	*Note 2*
Hydro One Sault Ste. Marie Inc. (H1N SSM)	$40,565,936	3,498.236	2,734.624	635.252	*Note 3*
Bruce to Milton Limited Partnership (B2M LP)	$33,700,000	-	-	-	*Note 4*

Note 1: FNEI Rates Revenue Requirement and Charge Determinants per Board Decision and Order on EB-2009-0387 dated December 9, 2010. Set as Interim on December 29, 2015 under EB-2015-0368.
Note 2: CNPI Rates Revenue Requirement and Charge Determinants per OEB Decision EB-2014-0204 dated June 25, 2015.
Note 3: H1N SSM 2017 Rates Revenue Requirement and Charge Determinants per OEB Decision EB-2016-0356, issued September 28, 2017.
Note 4: B2M LP 2017 Revenue Requirement per Board Decision and Order EB-2016-0349 dated June 29, 2017.

2017 ONTARIO UNIFORM TRANSMISSION RATE SCHEDULES

EB-2016-0160
EB-2017-0280

The rate schedules contained herein shall be effective January 1, 2017 and Implemented as of November 1, 2017

Issued: November, 2017
Ontario Energy Board

TERMS AND CONDITIONS

(A) APPLICABILITY The rate schedules contained herein pertain to the transmission service applicable to: •The provision of Provincial Transmission Service (PTS) to the Transmission Customers who are defined as the entities that withdraw electricity directly from the transmission system in the province of Ontario. •The provision of Export Transmission Service (ETS) to electricity market participants that export electricity to points outside Ontario utilizing the transmission system in the province of Ontario. The Rate Schedule ETS applies to the wholesale market participants who utilize the Export Service in accordance with the Market Rules of the Ontario Electricity Market, referred to hereafter as Market Rules. These rate schedules do not apply to the distribution services provided by any distributors in Ontario, nor to the purchase of energy, hourly uplift, ancillary services or any other charges that may be applicable in electricity markets administered by the Independent Electricity System Operator (IESO) of Ontario.

(B) TRANSMISSION SYSTEM CODE The transmission service provided under these rate schedules is in accordance with the Transmission System Code (Code) issued by the Ontario Energy Board (OEB). The Code sets out the requirements, standards, terms and conditions of the transmitter's obligation to offer to connect to, and maintain the operation of, the transmission system. The Code also sets out the requirements, standards, terms and conditions under which a Transmission Customer may connect to, and remain connected to, the transmission system. The Code stipulates that a transmitter shall connect new customers, and continue to offer transmission services to existing customers, subject to a Connection Agreement between the customer and a transmitter.

(C) TRANSMISSION DELIVERY POINT The Transmission Delivery Point is defined as the transformation station, owned by a transmission company or by the Transmission Customer, which steps down the voltage from above 50 kV to below 50 kV and which connects the customer to the transmission system. The demand registered by two or more meters at any one delivery point shall be aggregated for the purpose of assessing transmission charges at that delivery point if the corresponding distribution feeders from that delivery point, or the plants taking power from that delivery point, are owned by the same entity within the meaning of Ontario's *Business Corporations Act*. The billing demand supplied from the transmission system shall be adjusted for losses, as appropriate, to the Transmission Point of Settlement, which shall be the high voltage side of the transformer that steps down the voltage from above 50 kV to below 50 kV.

(D) TRANSMISSION SERVICE POOLS The transmission facilities owned by the licenced transmission companies are categorized into three functional pools. The transmission lines that are used for the common benefit of all customers are categorized as Network Lines and the corresponding terminating facilities are Network Stations. These facilities make up the Network Pool. The transformation station facilities that step down the voltage from above 50 kV to below 50 kV are categorized as the Transformation Connection Pool. Other electrical facilities (i.e. that are neither Network nor Transformation) are categorized as the Line Connection Pool. All PTS customers incur charges based on the Network Service Rate (PTS-N) of Rate Schedule PTS. The PTS customers that utilize transformation connection assets owned by a licenced transmission company also incur charges based on the Transformation Connection Service Rate (PTS-T). The customer demand supplied from a transmission delivery point will not incur transformation connection service charges if a customer fully owns all transformation connection assets associated with that transmission delivery point. The PTS customers utilize lines owned by a licenced transmission company to connect to Network Station(s) also incur charges based on the Line Connection Service Rate (PTS- L). The customer demand supplied from a transmission delivery point will not incur line connection service charges if a customer fully owns all line connection assets connecting that delivery point to a Network Station. Similarly, the customer demand will not incur line connection service charges for demand at a transmission delivery point located at a Network Station.

(E) MARKET RULES The IESO will provide transmission service utilizing the facilities owned by the licenced transmission companies in Ontario in accordance with the Market Rules. The Market Rules and appropriate Market Manuals define the procedures and processes under which the transmission service is provided in real or operating time (on an hourly basis) as well as service billing and settlement processes for transmission service charges based on rate schedules contained herein.

(F) METERING REQUIREMENTS In accordance with Market Rules and the Transmission System Code, the transmission service charges payable by Transmission Customers shall be collected by the IESO. The IESO will utilize Registered Wholesale Meters and a Metering Registry in order to calculate the monthly transmission service charges payable by the Transmission Customers. Every Transmission Customer shall ensure that each metering installation in respect of which the customer has an obligation to pay transmission service charges arising from the Rate Schedule PTS shall satisfy the Wholesale Metering requirements and associated obligations specified in Chapter 6 of the Market Rules, including the appendices therein, whether or not the subject meter installation is required for settlement purposes in the IESO-administered energy market. A meter installation required for the settlement of charges in the IESO-administered that energy market may be used for the settlement of transmission service charges. The Transmission Customer shall provide to the IESO data required to maintain the information for the Registered Wholesale Meters and the Metering Registry pertaining to the metering installations with respect to which the Transmission Customers have an obligation to pay transmission charges in accordance with Rate Schedule PTS. The Metering Registry for metering installations required for the calculation of transmission charges shall be maintained in accordance with Chapter 6 of the Market Rules. The Transmission Customers, or Transmission Customer Agents if designated by the Transmission Customers, associated with each Transmission Delivery Point will be identified as Metered Market Participants within the IESO's Metering Registry. The metering data recorded in the Metering Registry shall be used as the basis for the calculation of transmission charges on the settlement statement for the Transmission Customers identified as the Metered Market Participants for each Transmission Delivery Point. The Metering Registry for metering installations required for calculation of transmission charges shall also indicate whether or not the demand associated with specific Transmission Delivery Point(s) to which a Transmission Customer is connected attracts Line and/or Transformation Connection Service Charges. This information shall be consistent with the Connection Agreement between the Transmission Customer and the licenced Transmission Company that connects the customer to the IESO-Controlled Grid.

(G) EMBEDDED GENERATION The Transmission Customers shall ensure conformance of Registered Wholesale Meters in accordance with Chapter 6 of Market Rules, including Metering Registry obligations, with respect to metering installations for embedded generation that is located behind the metering installation that measures the net demand taken from the transmission system if (a) the required approvals for such generation are obtained after October 30, 1998; and (b) the generator unit rating is 2 MW or higher for renewable generation and 1 MW or higher for non-renewable generation; and (c) the Transmission Delivery Point through which the generator is connected to the transmission system attracts Line or Transformation Connection Service charges. These terms and conditions also apply to the incremental capacity associated with any refurbishments approved after October 30, 1998, to a generator unit that was connected through an eligible Transmission Delivery Point on or prior to October 30, 1998 and the approved incremental capacity is 2 MW or higher for renewable generation and 1 MW or higher for non-renewable generation. The term renewable generation refers to a facility that generates electricity from the following sources: wind, solar, Biomass, Bio-oil, Bio-gas, landfill gas, or water. Accordingly, the distributors that are Transmission Customers shall ensure that connection agreements between them and the generators, load customers, and embedded distributors connected to their distribution system have provisions requiring the Transmission Customer to satisfy the requirements for Registered Wholesale Meters and Metering Registry for such embedded generation even if the subject embedded generator(s) do not participate in the IESO-administered energy markets.

(H) EMBEDDED CONNECTION POINT In accordance with Chapter 6 of the Market Rules, the IESO may permit a Metered Market Participant, as defined in the Market Rules, to register a metering installation that is located at the embedded connection point for the purpose of recording transactions in the IESO-administered markets. (The Market Rules define an embedded connection point as a point of connection between load or generation facility and distribution system). In special situations, a metering installation at the embedded connection point that is used to settle energy market charges may also be used to settle transmission service charges, if there is no metering installation at the point of connection of a distribution feeder to the Transmission Delivery Point. In above situations: •The Transmission Customer may utilize the metering installation at the embedded connection point, including all embedded generation and load connected to that point, to satisfy the requirements described in Section (F) above provided that the same metering installation is also used to satisfy the requirement for energy transactions in the IESO- administered market. •The Transmission Customer shall provide the Metering Registry information for the metering installation at the embedded connection point, including all embedded generation and load connected to that point, in accordance with the requirements described in Section (F) above so that the IESO can calculate the monthly transmission service charges payable by the Transmission Customer.

RATE SCHEDULE: (PTS) PROVINCIAL TRANSMISSION RATES

APPLICABILITY:

The Provincial Transmission Service (PTS) is applicable to all Transmission Customers in Ontario who own facilities that are directly connected to the transmission system in Ontario and that withdraw electricity from this system.

	Monthly Rate ($ per kW)
Network Service Rate (PTS-N):	**3.52**
$ Per kW of Network Billing Demand [1,2]	
Line Connection Service Rate (PTS-L):	**0.88**
$ Per kW of Line Connection Billing Demand [1,3]	
Transformation Connection Service Rate (PTS-T):	**2.13**
$ Per kW of Transformation Connection Billing Demand [1,3,4]	

The rates quoted above shall be subject to adjustments with the approval of the Ontario Energy Board.

Notes:

1 The demand (MW) for the purpose of this rate schedule is measured as the energy consumed during the clock hour, on a "Per Transmission Delivery Point" basis. The billing demand supplied from the transmission system shall be adjusted for losses, as appropriate, to the Transmission Point of Settlement, which shall be the high voltage side of the transformer that steps down the voltage from above 50 kV to below 50 kV at the Transmission Delivery Point.

2. The Network Service Billing Demand is defined as the higher of (a) customer coincident peak demand (MW) in the hour of the month when the total hourly demand of all PTS customers is highest for the month, and (b) 85 % of the customer peak demand in any hour during the peak period 7 AM to 7 PM (local time) on weekdays, excluding the holidays as defined by IESO. The peak period hours will be between 0700 hours to 1900 hours Eastern Standard Time during winter (i.e. during standard time) and 0600 hours to 1800 hours Eastern Standard Time during summer (i.e. during daylight savings time), in conformance with the meter time standard used by the IMO settlement systems.

3. The Billing Demand for Line and Transformation Connection Services is defined as the Non-Coincident Peak demand (MW) in any hour of the month. The customer demand in any hour is the sum of (a) the loss-adjusted demand supplied from the transmission system plus (b) the demand that is supplied by an embedded generator unit for which the required government approvals are obtained after October 30, 1998 and which have installed capacity of 2MW or more for renewable generation and 1 MW or higher for non-renewable generation, on the demand supplied by the incremental capacity associated with a refurbishment approved after October 30, 1998, to a generator unit that existed on or prior to October 30, 1998.. The term renewable generation refers to a facility that generates electricity from the following sources: wind, solar, Biomass, Bio-oil, Bio-gas, landfill gas, or water. The demand supplied by embedded generation will not be adjusted for losses.

4. The Transformation Connection rate includes recovery for OEB approved Low Voltage Switchgear compensation for Toronto Hydro Electric System Limited and Hydro Ottawa Limited.

TERMS AND CONDITIONS OF SERVICE:

The attached Terms and Conditions pertaining to the Transmission Rate Schedules, the relevant provisions of the Transmission System Code, in particular the Connection Agreement as per Appendix 1 of the Transmission System Code, and the Market Rules for the Ontario Electricity Market shall apply, as contemplated therein, to services provided under this Rate Schedule.

RATE SCHEDULE: (ETS) EXPORT TRANSMISSION SERVICE

APPLICABILITY:

The Export Transmission Service is applicable for the use of the transmission system in Ontario to deliver electrical energy to locations external to the Province of Ontario, irrespective of whether this energy is supplied from generating sources within or outside Ontario.

	Hourly Rate
Export Transmission Service Rate (ETS):	$1.85 / MWh

The ETS rate shall be applied to the export transactions in the Interchange Schedule Data as per the Market Rules for Ontario's Electricity Market. The ETS rate shall be subject to adjustments with the approval of the Ontario Energy Board.

TERMS AND CONDITIONS OF SERVICE:

The attached Terms and Conditions pertaining to the Transmission Rate Schedules, the relevant provisions of the Transmission System Code and the Market Rules for the Ontario Electricity Market shall apply, as contemplated therein, to service provided under this Rate Schedule.

HYDRO ONE NETWORKS INC.
WHOLESALE METER SERVICE
AND EXIT FEE SCHEDULE

HYDRO ONE NETWORKS - WHOLESALE METER SERVICE

APPLICABILITY:

This fee schedule is applicable to the *metered market participants** that are transmission customers of Hydro One Networks ("Networks") and to *metered market participants* that are customers of a Local Distribution Company ("LDC") that is connected to the transmission system owned by Networks.

* The terms and acronyms that are italicized in this schedule have the meanings ascribed thereto in Chapter 11 of the Market Rules for the Ontario Electricity Market.

a) Fee for Wholesale Meter Service

The *metered market participant* in respect of a *load facility* (including customers of an LDC) shall be required to pay an annual fee of $7,900 for each *meter point* that is under the transitional arrangement for a *metering installation* in accordance with Section 3.2 of Chapter 6 of the Market Rules for the Ontario Electricity Market.

This Wholesale Meter Service annual fee shall remain in place until all the remaining meter points exit the transitional arrangement.

b) Fee for Exit from Transitional Arrangement

The *metered market participant* in respect of a *load facility* (including customers of an LDC) or a *generation facility* may exit from the transitional arrangement for a *metering installation* upon payment of a one-time exit fee of $ 5,200 per *meter point*.

Hydro One Networks Inc.

Implementation of Decision with Reasons on EB-2016-0160

Low Voltage Switchgear (LVSG) Credit
Effective January 1, 2017

Charge Determinant (MW) *(Note 1)*	**Transformation Pool Revenue Requirement Before LVSG Credit ($M)** *(Note 2)*	**Rate Before LVSG Credit ($/kw/month)**	**Total Annual 2017 NCP Demand for Toronto Hydro and Hydro Ottawa (MW)** *(Note 3)*	**LVS Proportion (%)** *(Note 4)*	**Final Annual LVSG Credit ($M)** *(Note 5)*
(A)	(B)	(C) = (B)/(A)	(D)	(E)	(F) = (C)x(D)x(E)
202,461	405.2	2.00	35,132	19.0%	13.4

Note 1: Per Exhibit 5.0
Note 2: Equals Total Revenue Requirement for Transformation Connection Pool less Non-Rate Revenues allocated to Transformation Connection Pool, as per information in Exhibit 3.0
Note 3: Per EB-2016-0160, Exhibit G1, Tab 3, Schedule 1, Table 6; Sum of Toronto Hydro and Hydro Ottawa total annual 2017 NCP Demand, 27,141 MW and 7,991 MW, respectively.
Note 4: Per EB-2016-0160, Exhibit G1, Tab 3, Schedule 1, page 7
Note 5: Per EB-2016-0160, Exhibit G1, Tab 3, Schedule 1, Table 6; Sum of Toronto Hydro and Hydro Ottawa total annual 2017 LVSG credit, $10,320,467 and $3,038,634 , respectively.

Hydro One Networks Inc.

Implementation of Decision with Reasons on EB-2016-0160

2017 Bill Impacts on Transmission-Connected and Distribution-Connected Customers

Table 1: Average Bill Impacts on Transmission and Distribution-connected Customers

Description	**2016**	**2017**
Rates Revenue Requirement[1]	$ 1,480.5	$ 1,437.5
% Increase in Rates RR over prior year		-2.9%
% Impact of load forecast change		2.1%
Net Impact on Average Transmission Rates		-0.8%
Transmission as a % of Tx-connected customer's Total Bill		8.3%
Estimated Average Bill impact		-0.1%
Transmission as a % of Dx-connected customer's Total Bill		6.8%
Estimated Average Bill impact		-0.1%

[1]Includes MSP revenue of -$0.3M as shown in Exhibit 3.0. This accounts for the difference from the total rates revenue requirement shown in Exhibit 2.0.

Table 2: Typical Medium Density (R1) Residential Customer Bill Impacts

	Typical R1 Residential Customer		
	350 kWh	**750 kWh**	**1800 kWh**
Total Bill as of May 1, 2016[1]	$ 102.95	$ 179.37	$ 379.98
RTSR included in 2016 R1 Customer's Bill	$ 4.37	$ 9.36	$ 22.47
Estimated 2017 RTSR[2]	$ 4.34	$ 9.29	$ 22.30
2017 change in Monthly Bill	**$ (0.03)**	**$ (0.07)**	**$ (0.17)**
2017 change as a % of total bill	*0.0%*	*0.0%*	*0.0%*

[1]Total bill including HST, based on time-of-use commodity pricing effective May 1, 2016 and 2016 distribution rates approved per Distribution Rate Order EB-2015-0079

[2]The impact on RTSR is assumed to be the net impact on average Transmission rates per Table 1, adjusted for Hydro One's revenue disbursement allocator per approved 2016 UTRs

Table 3: Typical General Service Energy less than 50 kW (GSe < 50 kW) Customer Bill Impacts

	GSe Customer Monthly Bill		
	1,000 kWh	**2,000 kWh**	**15,000 kWh**
Total Bill as of May 1, 2016[1]	$ 262.79	$ 492.00	$ 3,471.80
RTSR included in 2016 GSe Customer's Bill	$ 10.19	$ 20.39	$ 152.89
Estimated 2017 RTSR[2]	$ 10.11	$ 20.23	$ 151.72
2017 change in Monthly Bill	**$ (0.08)**	**$ (0.16)**	**$ (1.17)**
2017 change as a % of total bill	*0.0%*	*0.0%*	*0.0%*

[1]Total bill including HST, based on time-of-use commodity pricing effective May 1, 2016 and 2016 distribution rates approved per Distribution Rate Order EB-2015-0079

[2]The impact on RTSR is assumed to be the net impact on average Transmission rates per Table 1, adjusted for Hydro One's revenue disbursement allocator per approved 2016 UTRs

Hydro One Networks Inc.

Implementation of Decision with Reasons on EB-2016-0160

2017 Foregone Revenue Calculation

HONI Transmission Charge Determinant Forecast for the Year 2017, After Deducting the Load Impact of CDM and Embedded Generation (MW)

Charge Determinant	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Total
Network	21,081	20,558	20,269	18,074	19,383	21,977	22,833	21,929	20,197	18,234	19,535	20,795	244,866
Line Connection	20,138	19,728	19,307	17,381	19,002	20,933	22,160	21,140	19,647	18,029	18,878	20,547	236,891
Transformation Connection	17,264	16,973	16,645	14,788	16,304	18,010	19,103	18,095	17,142	14,829	15,862	17,446	202,461

Monthly Charge Determinant Share of Annual Total

% Share	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Total
Network	8.61%	8.40%	8.28%	7.38%	7.92%	8.98%	9.32%	8.96%	8.25%	7.45%	7.98%	8.49%	100.00%
Line Connection	8.50%	8.33%	8.15%	7.34%	8.02%	8.84%	9.35%	8.92%	8.29%	7.61%	7.97%	8.67%	100.00%
Transformation Connection	8.53%	8.38%	8.22%	7.30%	8.05%	8.90%	9.44%	8.94%	8.47%	7.32%	7.83%	8.62%	100.00%

2017 UTR Charge Determinant (including all Transmitters)

Charge Determinant	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Total
Network	21,444	20,912	20,617	18,384	19,717	22,355	23,226	22,306	20,544	18,548	19,871	21,152	249,074
Line Connection	20,436	20,020	19,592	17,637	19,283	21,242	22,488	21,452	19,937	18,295	19,157	20,850	240,388
Transformation Connection	17,372	17,079	16,749	14,880	16,405	18,122	19,222	18,208	17,248	14,921	15,961	17,555	203,722

2016 Approved UTRs

	$/kw-month	Hydro One Revenue Allocators
Network	3.66	0.93219
Line Connection	0.87	0.96648
Transformation Connection	2.02	0.96648

1. 2017 Revenue at 2016 Approved Rates and 2017 Load Forecast

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Total
Network	73.2	71.3	70.3	62.7	67.3	76.3	79.2	76.1	70.1	63.3	67.8	72.2	849.8
Line Connection	17.2	16.8	16.5	14.8	16.2	17.9	18.9	18.0	16.8	15.4	16.1	17.5	202.1
Transformation Connection	33.9	33.3	32.7	29.1	32.0	35.4	37.5	35.5	33.7	29.1	31.2	34.3	397.7
Total	**124.3**	**121.5**	**119.5**	**106.6**	**115.5**	**129.5**	**135.7**	**129.7**	**120.5**	**107.8**	**115.1**	**124.0**	**1,449.6**

Total to end of October = 1,210.6

2017 Forecast UTR Reflecting Board Decision

	$/kw-month	Hydro One Revenue Allocators
Network	3.52	0.92828
Line Connection	0.88	0.96539
Transformation Connection	2.13	0.96539

2. 2017 Revenue at Proposed UTR Rates and 2017 Load Forecast

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Total
Network	70.1	68.3	67.4	60.1	64.4	73.0	75.9	72.9	67.1	60.6	64.9	69.1	813.9
Line Connection	17.4	17.0	16.6	15.0	16.4	18.0	19.1	18.2	16.9	15.5	16.3	17.7	204.2
Transformation Connection	35.7	35.1	34.4	30.6	33.7	37.3	39.5	37.4	35.5	30.7	32.8	36.1	418.9
Total	**123.1**	**120.5**	**118.5**	**105.7**	**114.5**	**128.4**	**134.5**	**128.5**	**119.5**	**106.8**	**114.0**	**122.9**	**1,437.0**

Total to end of October = 1,200.0

2017 Forgone Revenue (2 - 1)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Total
Network	-3.1	-3.0	-3.0	-2.7	-2.8	-3.2	-3.4	-3.2	-3.0	-2.7	-2.9	-3.1	-35.9
Line Connection	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	2.1
Transformation Connection	1.8	1.8	1.7	1.5	1.7	1.9	2.0	1.9	1.8	1.6	1.7	1.8	-33.8
Total	**-1.1**	**-1.1**	**-1.1**	**-1.0**	**-1.0**	**-1.2**	**-1.2**	**-1.1**	**-1.0**	**-1.0**	**-1.0**	**-1.0**	**-12.7**

Total to end of October = -10.6