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

BY COURIER

December 4, 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-2017-0359 - 2018 Uniform Transmission Rates

Pursuant to the Ontario Energy Board's (the "**OEB**") decisions dated September 28, November 9 and November 23, 2017 in the above-noted proceeding (collectively, the "**Decision**"), please find attached a draft revenue requirement/charge determinant order and draft UTR rate order and supporting schedules for 2018, reflecting the directions provided in the Decision.

The 2018 proposed revenue requirement has increased to $1,623.8 million from the $1,599.4 million last shown in the 2017 draft revenue requirement order materials. This reflects the 2017 actual debt issuances, 2018 forecast issuances, and the OEB's applicable cost of capital parameters issued on November 23, 2017. The underlying assumptions and revenue requirement calculations are set out in the attached supporting documentation Exhibit 1.0.

The 2018 UTRs in $/kW-Month are determined to be $3.59 for Network, $0.94 for Line Connection and $2.33 for Transformation Connection. The calculation of the 2018 UTRs, wholesale meter rates, low voltage switchgear credit, charge determinants, revenue disbursement allocators, and bill impacts resulting from the OEB's findings are detailed in Exhibits 2.0 to 7.0. Hydro One's revenue to be collected in the 2018 UTRs includes the application of the approved -$10.6 million in 2017 foregone revenue, allocated across the three rate pools consistent with the details provided in Exhibit 9.0 of Hydro One's updated Draft Rate Order submitted on November 16, 2017. The revenue requirement and charge determinants used for other Ontario transmitters in calculating the 2018 UTRs reflect their current OEB-approved values, which remain the same as used for calculating the 2017 UTRs, and are set out in Exhibit 4.1.

As directed by the OEB, 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

Hydro One Networks Inc.

Implementation of Decision with Reasons on EB-2016-0160

Revenue Requirement Summary

($ millions)	**Supporting Reference**	**OEB Approved 2018**	**CoC Update 2018**	**OEB Revised 2018**
OM&A	Exhibit 1.1	394.3	-	394.3
Depreciation	Exhibit 1.2	468.6	-	468.6
Return on Debt	Exhibit 1.4	289.9	12.3	302.3
Return on Equity	Exhibit 1.4	391.5	9.8	401.3
Income Tax (Note 1)	Exhibit 1.5	55.1	2.2	57.2
Base Revenue Requirement		**1,599.4**	**24.3**	**1,623.8**
Deduct: External Revenue	Exhibit 1.6	(28.5)	-	(28.5)
Subtotal		**1,570.9**	**24.3**	**1,595.3**
Deduct: Export Tx Service Revenue	Exhibit 1.7	(40.1)	-	(40.1)
Deduct: Other Cost Charges	Exhibit 1.8	(47.8)	-	(47.8)
Deduct: MSP Revenue		(0.3)	-	(0.3)
Add: 2017 Foregone Revenue		(10.6)	-	(10.6)
Add: Low Voltage Switch Gear		13.9	0.2	14.1
Rates Revenue Requirement (Note 2)		**1,486.2**	**24.6**	**1,510.7**

Note 1: OEB approved Income Tax based on 62% allocation factor.
Note 2: Rates Revenue Requirement includes MSP Revenue and 2017 Foregone Revenue

Hydro One Networks Inc.

Implementation of Decision with Reasons on EB-2016-0160

OM&A

($ millions)	**Supporting Reference**	**OEB Approved 2018**	**CoC Update 2018**	**OEB Revised 2018**
OM&A		394.3		394.3

Hydro One Networks Inc.

Implementation of Decision with Reasons on EB-2016-0160

Rate Base and Depreciation

($ millions)	**Supporting Reference**	**OEB Approved 2018**	**CoC Update 2018**	**OEB Revised 2018**
Rate Base		11,148.0	-	11,148.0
Depreciation		468.6	-	468.6

Hydro One Networks Inc.

Implementation of Decision with Reasons on EB-2016-0160

Capital Expenditures and In-Service

($ millions)	**Supporting Reference**	**OEB Approved 2018**	**CoC Update 2018**	**OEB Revised 2018**
Capital expenditures		1,000.0	-	1,000.0

Hydro One Networks Inc.

Implementation of Decision with Reasons on EB-2016-0160

Capital Structure and Return on Capital

($ millions)	**Supporting Reference**	**OEB Approved 2018**	**CoC Update 2018**	**OEB Revised 2018**
Return on Rate Base				
Rate Base	Exhibit 1.2	$ 11,148.0	$ -	$ 11,148.0
Capital Structure:				
Third-Party long-term debt		54.95%	(5.90%)	49.05%
Deemed long-term debt		1.05%	5.90%	6.95%
Short-term debt		4.00%	0.00%	4.00%
Common equity		40.00%	0.00%	40.00%
Capital Structure:				
Third-Party long-term debt	Exhibit 1.4.1	6,125.4	(657.3)	5,468.1
Deemed long-term debt		117.5	657.3	774.8
Short-term debt		445.9	-	445.9
Common equity		4,459.2	-	4,459.2
		11,148.0	**(0.0)**	**11,148.0**
Allowed Return:				
Third-Party long-term debt	Exhibit 1.4.1	4.52%	0.16%	4.68%
Deemed long-term debt	Exhibit 1.4.1	4.52%	0.16%	4.68%
Short-term debt		1.76%	0.53%	2.29%
Common equity		8.78%	0.22%	9.00%
Return on Capital:				
Third-Party long-term debt		276.8	(21.0)	255.8
Deemed long-term debt		5.3	30.9	36.2
Short-term debt		7.8	2.4	10.2
AFUDC return on Niagara Reinforcement Project		-	-	-
Total return on debt		**289.9**	**$ 12.3**	**$ 302.3**
Common equity		**$ 391.5**	**$ 9.8**	**$ 401.3**

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	0.0	0.0	0.0	100.0	3.67%	0.0	0.0	-	0.0	Note 1
34	15-Jun-17	2.606%	15-Jun-27	0.0	0.0	0.0	100.0	2.61%	0.0	0.0	-	0.0	Note 1
35	15-Jun-17	3.670%	15-Jun-47	0.0	0.0	0.0	100.0	3.67%	0.0	0.0	-	0.0	Note 1
36	15-Sep-17	2.606%	15-Sep-27	0.0	0.0	0.0	100.0	2.61%	0.0	0.0	-	0.0	Note 1
37	15-Mar-18	4.185%	15-Mar-48	296.6	1.5	295.2	99.50	4.21%	0.0	296.6	228.2	9.6	Note 2
38	15-Jun-18	3.377%	15-Jun-28	296.6	1.5	295.2	99.50	3.44%	0.0	296.6	159.7	5.5	Note 2
39	15-Sep-18	2.824%	15-Sep-23	296.6	1.5	295.2	99.50	2.93%	0.0	296.6	91.3	2.7	Note 2
40		**Subtotal**							5084.1	5561.5	5468.1	249.8	
41		Treasury OM&A costs										2.0	
42		Other financing-related fees										4.1	
43		**Total**							5084.1	5561.5	5468.1	255.8	4.68%

Note 1: Updated to reflect actual 2017 debt issuance

Note 2: Updated to reflect the forecast coupon rates for 2018 as per Hydro One Inc. Spreads and Consensus Forecast (3 and 12 month 10 year Government Bond Yield average), both from September 2017

Hydro One Networks Inc.

Implementation of Decision with Reasons on EB-2016-0160

Income Tax

($ millions)	Supporting Reference		OEB Approved 2018	CoC Update 2018	OEB Revised 2018
Income Taxes	*See supporting details below*		55.1	2.2	57.2

Income Tax Supporting Details			OEB Approved 2018	CoC Update 2018	OEB Revised 2018
Rate Base	Exhibit 1.2	a	$ 11,148.0	$ -	$ 11,148.0
Common Equity Capital Structure		b	40.0%		40.0%
Return on Equity	Exhibit 1.4	c	8.78%	0.22%	9.00%
Return on Equity		d = a x b x c	391.5	9.8	401.3
Regulatory Income Tax		e = l	88.8	3.54	92.3
Regulatory Net Income (before tax)		f = d + e	480.3	13.35	493.7
Timing Differences *(Note 1)*		g	(142.1)	-	(142.1)
Taxable Income		h = f + g	338.2	13.35	351.5
Tax Rate		i	26.5%		26.5%
Income Tax		j = h x i	89.6	3.54	93.2
less: Income Tax Credits		k	(0.8)	-	(0.8)
Regulatory Income Tax		l = j + k	88.8	3.54	92.3
less: Deferred Tax Asset Sharing *[Note 2]*		m	(33.7)	(1.34)	(35.1)
Income Taxes		n = l + m	55.1	2.2	57.2

Note 1. Book to Tax Timing Differences	OEB Approved 2018	CoC Update 2018	OEB Revised 2018
Depreciation	468.6	-	468.6
CCA	(545.4)	-	(545.4)
Other Timing Differences	(65.4)	-	(65.4)
Total Timing Differences	(142.1)	-	(142.1)

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

	OEB Approved 2018	CoC Update 2018	OEB Revised 2018
Income Tax from OEB Decision (Pre-DTA Sharing)	88.8		92.3
Deferred Tax Asset Sharing	33.7		35.1

Hydro One Networks Inc.

Implementation of Decision with Reasons on EB-2016-0160

External Revenue

($ millions)	**Supporting Reference**	**OEB Approved 2018**	**CoC Update 2018**	**OEB Revised 2018**
External Revenue	*See supporting details below*	28.5	-	28.5

External Revenue Details E1-2-1 Page 2	**OEB Approved 2018**	**CoC Update 2018**	**OEB Revised 2018**
Secondary Land Use	15.6	-	15.6
Station Maintenance	5.3	-	5.3
Engineering & Construction	-	-	-
Other	7.6	-	7.6
Total	28.5	-	28.5

Hydro One Networks Inc.

Implementation of Decision with Reasons on EB-2016-0160

Export Transmission Service Revenue

($ millions)	**Supporting Reference**	**OEB Approved 2018**	**CoC Update 2018**	**OEB Revised 2018**
Export Transmission Service Revenue		(40.1)		(40.1)

Hydro One Networks Inc.

Implementation of Decision with Reasons on EB-2016-0160

Deferral and Variance Accounts

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

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

Hydro One Networks Inc.

Implementation of Decision with Reasons on EB-2016-0160

2018 Revenue Requirement by Rate Pool

		2018 Rate Pool Revenue Requirement ($ Million)			
	Supporting Exhibit	**Network (Note 3)**	**Line Connection**	**Transformation Connection**	**Uniform Transmission Rates Revenue Requirement**
OM&A	*1.1*	194.1	39.7	96.2	330.0
Other Taxes (Grants-in-Lieu)	*Note 1*	38.0	9.5	16.9	64.3
Depreciation of Fixed Assets	*1.2*	229.5	55.8	116.7	402.0
Capitalized Depreciation	*Note 2*	(7.5)	(1.9)	(3.4)	(12.8)
Asset Removal Costs	*Note 2*	40.6	10.3	18.3	69.2
Other Amortization	*Note 2*	6.0	1.5	2.7	10.1
Return on Debt	*1.4*	178.5	44.5	79.3	302.3
Return on Equity	*1.4*	237.0	59.1	105.2	401.3
Income Tax	*1.5*	33.8	8.4	15.0	57.2
Base Revenue Requirement		**950.0**	**226.9**	**446.9**	**1623.8**
Less External Revenues	*1.6*	(16.7)	(4.0)	(7.8)	(28.5)
Total Revenue Requirement		**933.3**	**222.9**	**439.0**	**1595.3**
Less MSP Revenue	*Note 3*			(0.3)	(0.3)
Less Export Revenues	*1.7*	(40.1)			(40.1)
Less Regulatory Asset Credit	*1.8*	(31.8)	(5.4)	(10.6)	(47.8)
Plus LVSG Credit	*6.0*			14.1	14.1
Plus 2017 Foregone Revenue	*Note 4*	(30.0)	1.7	17.7	(10.6)
Total Rates Revenue Requirement	*Note 3*	**831.5**	**219.3**	**459.9**	**1510.7**

Note 1: Included in OEB Approved 2018 OMA total in Exhibit 1.1.

Note 2: Included in OEB Approved 2018 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.

Note 4: 2017 Foregone Revenue as per OEB Decision EB-2016-0160, issued on November 23, 2017, and allocation to Rate Pools as per 2017 Draft Rate Order, EB-2016-0160 Exhibit 9.0.

Hydro One Networks Inc.

Implementation of Decision with Reasons on EB-2016-0160

Summary Charge Determinants

(for Setting Uniform Transmission Rates effective January 1, 2018 to December 31, 2018)

	2018 Total MW (Note 1)
Network	244,924.157
Line Connection	236,948.242
Transformation Connection	202,510.123

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
(for Period January 1, 2018 to December 31, 2018)

Transmitter	Revenue Requirement ($)			
	Network	Line Connection	Transformation Connection	Total
FNEI	$3,482,429	$918,326	$1,926,334	$6,327,089
CNPI	$2,557,819	$674,504	$1,414,878	$4,647,201
H1N SSM	$22,327,484.01	$5,887,821	$12,350,631	$40,565,936
H1N	$831,494,343	$219,267,431	$459,947,909	$1,510,709,684
B2MLP	$33,700,000	$0	$0	$33,700,000
All Transmitters	$893,562,074	$226,748,083	$475,639,752	$1,595,949,910

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	244,924.157	236,948.242	202,510.123	
B2MLP	0.000	0.000	0.000	
All Transmitters	249,132.407	240,445.584	203,770.823	

Transmitter	Uniform Rates and Revenue Allocators			
	Network	Line Connection	Transformation Connection	
Uniform Transmission Rates ($/kW-Month)	**3.59**	**0.94**	**2.33**	
	↓	↓	↓	
FNEI Allocation Factor	**0.00390**	**0.00405**	**0.00405**	
CNPI Allocation Factor	**0.00286**	**0.00297**	**0.00297**	
H1N SSM Allocation Factor	**0.02499**	**0.02597**	**0.02597**	
H1N Allocation Factor	**0.93054**	**0.96701**	**0.96701**	
B2MLP Allocation Factor	**0.03771**	**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 (including 2017 Foregone Revenue) per OEB Decision EB-2016-0160 issued on November 23, 2017, updated for 2018 Cost of Capital Parameters per OEB Letter issued on November 23, 2017.

Note 5 : H1N Charge Determinants per OEB Decision EB-2016-0160, issued November 23, 2017.

Note 6: B2M LP 2017 Revenue Requirement per Board Decision and Order EB-2016-0349 dated June 29, 2017.

Note 7: Calculated data in shaded cells.

Hydro One Networks Inc.

Implementation of Decision with Reasons on EB-2016-0160

2018 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,
Note 4: B2M LP 2017 Revenue Requirement per Board Decision and Order EB-2016-0349 dated June 29, 2017.

2018 ONTARIO UNIFORM TRANSMISSION RATE SCHEDULES

EB-2016-0160
EB-2017-0359

The rate schedules contained herein shall be effective and Implemented as of January 1, 2018

Issued: December, 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):	**3.59**
$ Per kW of Network Billing Demand [1,2]	
Line Connection Service Rate (PTS-L):	**0.94**
$ Per kW of Line Connection Billing Demand [1,3]	
Transformation Connection Service Rate (PTS-T):	**2.33**
$ 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, 2018

Charge Determinant (MW) *(Note 1)*	**Transformation Pool Revenue Requirement Before LVSG Credit ($M)** *(Note 2)*	**Rate Before LVSG Credit ($/kw/month)**	**Total Annual 2018 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)
202,510	428.1	2.11	35,178	19.0%	14.1

Note 1: Per Exhibit 4.0

Note 2: Equals Total Revenue Requirement for Transformation Connection Pool less Non-Rate Revenues and 2017 Foregone Revenue allocated to Transformation Connection Pool, as per information in Exhibit 2.0.

Note 3: Per EB-2016-0160, Exhibit G1, Tab 3, Schedule 1, Table 6; Sum of Toronto Hydro and Hydro Ottawa total annual 2018 NCP Demand, 27,171 MW and 8,007 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 2018 LVSG credit, $10,913,609 and $3,216,284 , respectively.

Hydro One Networks Inc.

Implementation of Decision with Reasons on EB-2016-0160

2018 Bill Impacts on Transmission-Connected and Distribution-Connected Customers

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

Description	2017	2018
Rates Revenue Requirement[1]	$ 1,437.5	$ 1,510.7
% Increase in Rates RR over prior year		5.1%
% Impact of load forecast change		0.0%
Net Impact on Average Transmission Rates		5.1%
Transmission as a % of Tx-connected customer's Total Bill		8.3%
Estimated Average Bill impact		0.4%
Transmission as a % of Dx-connected customer's Total Bill		6.8%
Estimated Average Bill impact		0.3%

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

	Typical R1 Residential Customer		
	350 kWh	**750 kWh**	**1800 kWh**
Total Bill as of Jan 1, 2017[1]	$ 102.92	$ 179.30	$ 379.81
RTSR included in 2017 R1 Customer's Bill	$ 4.34	$ 9.29	$ 22.30
Estimated 2018 RTSR[2]	$ 4.54	$ 9.74	$ 23.37
2018 change in Monthly Bill	**$ 0.21**	**$ 0.45**	**$ 1.07**
2018 change as a % of total bill	*0.2%*	*0.2%*	*0.3%*

[1]Total 2017 bill based on total actual 2016 bill updated with estimate 2017 RTSR charges, as per EB-2016-0160 DRO Exhibit 8.0 filed on November 16, 2017.

[2]The impact on RTSR is assumed to be the net impact on average Transmission rates, as per Table 1, adjusted for Hydro One's revenue disbursement allocator per approved 2017 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 Jan 1, 2017[1]	$ 262.71	$ 491.85	$ 3,470.63
RTSR included in 2017 R1 Customer's Bill	$ 10.11	$ 20.23	$ 151.72
Estimated 2018 RTSR[2]	$ 10.60	$ 21.21	$ 159.04
2018 change in Monthly Bill	**$ 0.49**	**$ 0.98**	**$ 7.32**
2018 change as a % of total bill	*0.2%*	*0.2%*	*0.2%*

[1]Total 2017 bill based on total actual 2016 bill updated with estimate 2017 RTSR charges, as per EB-2016-0160 DRO Exhibit 8.0 filed on November 16, 2017.

[2]The impact on RTSR is assumed to be the net impact on average Transmission rates, as per Table 1, adjusted for Hydro One's revenue disbursement allocator per approved 2017 UTRs.