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Susan Frank
Vice President and Chief Regulatory Officer
Regulatory Affairs

BY COURIER

November 30, 2012

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

Dear Ms. Walli

EB-2012-0031 – Hydro One Networks' 2013-2014 Electricity Transmission Revenue Requirement – Final Revenue Requirements & Charge Determinants in Accordance with OEB Decision

On November 8, 2012 the Board in an oral Decision accepted the Settlement Agreement reached between Hydro One Networks Inc. ("Hydro One") and the intervenors who participated in the settlement process. The Board directed Hydro One to file with the Board and all intervenors of record a draft rate order no later than November 30, 2012.

Attached please find the requested draft rate order, as well as documentation providing a clear explanation of all calculations and assumptions used in deriving the amounts used in these exhibits, as specified by the Board. The revenue requirements of $1,437.7 million for 2013 and $1,528.4 million in 2014 are detailed in Exhibits 1.0 to 1.9. The calculation of the 2013 Uniform Transmission Rates ("UTR's"), wholesale meter rates, low voltage switchgear credit, charge determinants and revenue shares resulting from the Board's findings in its Decision are detailed in Exhibits 2.0 to 6.0. The 2013 UTR's in $/kW-Month are determined to be $3.63 for Network, $0.75 for Line Connection and $1.85 for Transformation Connection. The revenue requirement and annual charge determinants shown in Exhibits 4.0 and 4.1 for Great Lakes Power Transmission LP ("GLPT") are per the Draft Rate Order submitted by GLPT (EB-2012-0300) on November 26, 2012. In addition, a listing of all variance and deferral accounts as approved by the Board as outlined in the Settlement Agreement are provided in Exhibit 7. The Settlement Agreement itself is provided as Exhibit 8.

The attached exhibits reflect all changes as approved by the Board resulting from the Settlement Agreement to Hydro One's proposed submission as summarized in Hydro One's prefiled evidence. In summary, Hydro One has:

- Reduced OM&A costs by $13 million for 2013 and $10 million for 2014.
- Reduced capital expenditures in 2013 by $120 million and adjusted 2013 and 2014 rate base and revenue requirement accordingly.
- Increased external revenues by $4.8 million for 2014.
- Increased the Apprenticeship Tax Credit by $1.3 million in 2013 and $1.0 million in 2014 thus reducing tax expenses for the test years.
- Applied the cost of capital parameters released by the Board on November 15, 2012 for purposes of establishing Hydro One's Cost of Capital for 2013. The 2014 test year Cost of Capital parameters will be set based upon September 2013 data which will be issued by the OEB in due course.
- Updated the average cost of embedded debt for 2013 and 2014 by incorporating the actual principal amount and cost rate for debt issued in 2012, and the forecast coupon rates for 2013 (per the September 2012 consensus forecast) and for 2014 (per the October 2012 long-term consensus forecast).
- Deferred ($15.1) million of the ($30.3) million deferral and variance account balance owing customers to 2014 in order to help maintain a 0% increase in rates revenue requirement for 2013 as per the terms of the Settlement Agreement.
- Updated the Low Voltage Switchgear Credit to reflect the reduced 2013 revenue requirement from the above changes.
- Updated the Wholesale Meter Rate to reflect an average rate of $7,900 for 2013 and 2014.

As part of the Settlement Agreement Hydro One and the Intervenors agreed to use the transmission rate rider associated with deferral and variance accounts owing as the balancing item to maintain a 0% increase in 2013. The impact of the latest Cost of Capital parameters issued by the Board on November 15, 2012, reduced rates revenue requirement by an amount which would result in a decrease of 0.3%. In discussion with Board staff and the Intervenors Hydro One suggested that the final Order should reflect a shift of $4.0 million in export transmission revenue from 2013 and 2014 in order to maintain the 2013 increase at 0%. Intervenors and Board staff agreed to this further adjustment in order to maintain the spirit of the Settlement Agreement on November 22, 2012. Exhibit 8.0 provides an update to Appendix B of the Settlement Agreement to show the impact of the 2013 Cost of Capital parameters and the shift of the $4.0 million in export revenues forecast. Hydro One requests the Board approve this additional adjustment. A variance account is in place to track any differences between actual and forecast export revenue levels for consideration in a future application.

Per the Board's direction on November 8, 2012, Hydro One has attached as Exhibit 9.0 the revised Transmission Connection Procedures. Hydro One has also attached a Summary of Connection Procedure Changes made to the existing Connection Procedures as Exhibit 9.1.

As directed by the Board, all intervenors, by copy of this letter, are notified of this filing with the Board and of the fact that they have the opportunity to provide comment, if any, to the Board within 7 calendar days from today.

If you have any questions regarding this submission please contact Jamie Waller at 416 345-6948.

Sincerely,

ORIGINAL SIGNED BY SUSAN FRANK

Susan Frank

Attach.
c. EB-2012-0031 Intervenors (electronic)

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EB-2012-0031 BOARD DECISION
<u>REVENUE REQUIREMENTS, CHARGE DETERMINANTS & OTHER</u>

7.4		Transmission Accounting Order – Long-Term Transmission Future Corridor Acquisition and Development Account
8.0	**November 6, 2012 Settlement Agreement**	
8.1		Revised Appendix A to November 6, 2012 Settlement Agreement
8.2		Revised Appendix B to November 6, 2012 Settlement Agreement
9.0	**Revised Transmission Connection Procedures**	
9.1		Summary of Transmission Connection Procedures Changes

Hydro One Networks Inc.
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Revenue Requirement Summary

($ millions)	Supporting Reference	Hydro One Proposed 2013	Hydro One Proposed 2014	OEB Decision Impact 2013	OEB Decision Impact 2014	OEB Approved 2013	OEB Approved 2014
OM&A	Exhibit 1.1	453.3	459.7	(13.0)	(10.0)	440.3	449.7
Depreciation	Exhibit 1.2	346.7	374.7	(1.7)	(3.3)	345.0	371.5
Return on Debt	Exhibit 1.4 *(Note 1)*	273.2	288.5	2.0	(3.4)	275.2	285.1
Return on Equity	Exhibit 1.4 *(Note 1)*	344.9	379.5	(10.8)	(10.8)	334.1	368.7
Income Tax	Exhibit 1.5	46.4	55.2	(3.3)	(1.8)	43.1	53.4
Base Revenue Requirement		**1,464.5**	**1,557.7**	**(26.7)**	**(29.3)**	**1,437.7**	**1,528.4**
Deduct: External Revenue	Exhibit 1.6	(31.6)	(31.8)	-	(4.8)	(31.6)	(36.6)
Subtotal		**1,432.9**	**1,525.9**	**(26.7)**	**(34.1)**	**1,406.1**	**1,491.8**
Deduct: Export Tx Service Revenue	Exhibit 1.7 *(Note 2)*	(31.0)	(30.1)	4.0	(4.0)	(27.0)	(34.1)
Deduct: Other Cost Charges	Exhibit 1.8 *(Note 3)*	(15.1)	(15.1)	15.1	(15.1)	-	(30.3)
Add: Low Voltage Switch Gear	*Note 4*	11.7	12.5	(0.1)	(0.4)	11.6	12.1
Rates Revenue Requirement		**1,398.5**	**1,493.1**	**(7.7)**	**(53.6)**	**1,390.8**	**1,439.5**

Note 1: The 2013 Cost of Capital is updated to reflect OEB approved parameters issued on November 15, 2012, updated forecast 2013 and 2014 third-party long-term debt rate and 2012 actual debt issues.
Note 2: The Export Rx Service Revenue is reduced by $4M in 2013 but increased by $4M in 2014 to keep the overall rate increase at 0% in 2013.
Note 3: As per Hydro One's Settlement Agreement approved by the Board on November 8th, 2012, the refund of Regulatory Accounts in the amount of $15.1M in 2013 is postponed to 2014 to keep the overall rate increase at 0% in 2013.
Note 4: The value of $12.1M for LVSG in 2014 is an estimate and will be revised once the 2014 Revenue Requirement is finalized in the fall of 2013.

Hydro One Networks Inc.
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OM&A

($ millions)	**Supporting Reference**	**Hydro One Proposed 2013**	**Hydro One Proposed 2014**	**OEB Decision Impact 2013**	**OEB Decision Impact 2014**	**OEB Approved 2013**	**OEB Approved 2014**
OM&A	*See supporting details below*	453.3	459.7	(13.0)	(10.0)	440.3	449.7

OEB Decision Impact Supporting Details

Adjustments	**Reference**	**2013 OM&A Impacts**	**2014 OM&A Impacts**
Settlement Agreement *(Note 1)*	Page 10	(13.0)	(10.0)
		(13.0)	(10.0)

Note 1: As per Hydro One's Settlement Agreement approved by the Board on November 8th, 2012, OM&A expenses are reduced by $13M in 2013 and $10M in 2014 from Hydro One's application filed on August 28, 2012.

Hydro One Networks Inc.
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Rate Base and Depreciation

($ millions)	**Supporting Reference**	**Hydro One Proposed 2013**	**Hydro One Proposed 2014**	**OEB Decision Impact 2013**	**OEB Decision Impact 2014**	**OEB Approved 2013**	**OEB Approved 2014**
Rate Base	*See supporting details below*	9,413.5	10,050.9	(60.0)	(117.3)	9,353.4	9,933.8
Depreciation	*See supporting details below*	346.7	374.7	(1.7)	(3.3)	345.0	371.5

OEB Decision Impact Supporting Details	**Reference**	**2013 Detailed Computation**	**2014 Detailed Computation**	**2013 Rate Base Impact**	**2014 Rate Base Impact**	**2013 Depreciation Impact**	**2014 Depreciation Impact**
<u>Working Capital Adjustment</u>							
Rate Base Details	Pre-filed Evidence Exh D1-1-1						
Utility plant (average)							
Gross plant at cost		14,368.2	15,293.7				
Less: Accumulated depreciation		(4,981.0)	(5,267.4)				
Add: CWIP		-	-				
Net utility plant		9,387.2	10,026.4				
Working capital							
Cash working capital		12.5	11.7				
Materials & supplies inventory		13.7	12.9				
Total working capital		26.2	24.6				
Total Rate Base		9,413.5	10,050.9				
Working capital as % of OM&A	(a)	5.8%	5.3%				
OM&A Reduction per Settlement Agreement	Exhibit 1.1 (b)	(13.0)	(10.0)				
Working capital reduction	(c) = (a) x (b)	(0.8)	(0.5)	(0.8)	(0.5)		
		2013 Capital Expenditures	**2014 Capital Expenditures**				
<u>Capital Expenditure Adjustments</u>							
Settlement Agreement *(Note 1)*	Page 14	(120.0)	-	(59.2)	(116.7)	(1.7)	(3.3)
Total		(120.0)	-	(60.0)	(117.3)	(1.7)	(3.3)

Note 1: As per Hydro One's Settlement Agreement approved by the Board on November 8th, 2012, Capital Expreditures are reduced by $120M in 2013 from Hydro One's application filed on August 28, 2012.

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Capital Expenditures

($ millions)	Supporting Reference	Hydro One Proposed 2013	Hydro One Proposed 2014	OEB Decision Impact 2013	OEB Decision Impact 2014	OEB Approved 2013	OEB Approved 2014
Capital Expenditures	*See supporting details below*	1,102.4	1,121.5	(120.0)	-	982.4	1,121.5

OEB Decision Impact Supporting Details		2013 Capex Impacts	2014 Capex Impacts
Settlement Agreement *(Note 1)*	Page 14	(120.0)	-
		(120.0)	-

Note 1: As per Hydro One's Settlement Agreement approved by the Board on November 8th, 2012, Capital Expreditures are reduced by $120M in 2013 from Hydro One's application filed on August 28, 2012.

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Capital Structure and Return on Capital

($ millions)	**Supporting Reference**	**Hydro One Proposed 2013**	**Hydro One Proposed 2014**	**OEB Decision Impact 2013**	**OEB Decision Impact 2014**	**OEB Approved 2013**	**OEB Approved 2014**
Return on Rate Base							*Note 3*
Rate Base	Exhibit 1.2	$ 9,413.5	$ 10,050.9	$ (60.0)	$ (117.3)	$ 9,353.4	$ 9,933.8
Capital Structure:							
Third-Party long-term debt		57.3%	58.6%	(2.4%)	(1.9%)	54.9%	56.7%
Deemed long-term debt		-1.3%	-2.6%	2.4%	1.9%	1.1%	-0.7%
Short-term debt		4.0%	4.0%	0.0%	0.0%	4.0%	4.0%
Common equity		40.0%	40.0%	0.0%	0.0%	40.0%	40.0%
Capital Structure:							
Third-Party long-term debt	Exhibit 1.4.1 and 1.4.2	5,389.8	5,890.8	(258.4)	(258.4)	5,131.4	5,632.4
Deemed long-term debt		(118.3)	(262.2)	224.7	192.8	106.5	(69.5)
Short-term debt		376.5	402.0	(2.4)	(4.7)	374.1	397.4
Common equity		3,765.4	4,020.4	(24.0)	(46.9)	3,741.4	3,973.5
		9,413.5	**10,050.9**	**$ (60.0)**	**$ (117.3)**	**9,353.4**	**9,933.8**
Allowed Return:							
Third-Party long-term debt	Exhibit 1.4.1 & 1.4.2	4.95%	4.83%	0.06%	(0.00%)	5.01%	4.83%
Deemed long-term debt	Exhibit 1.4.1 & 1.4.2 *(Note 1)*	4.95%	4.83%	0.06%	(0.00%)	5.01%	4.83%
Short-term debt	*Note 2*	2.01%	2.98%	0.07%	0.00%	2.08%	2.98%
Common equity	*Note 2*	9.16%	9.44%	(0.23%)	(0.16%)	8.93%	9.28%
Return on Capital:							
Third-Party long-term debt		266.5	284.4	(9.4)	(12.6)	257.1	271.9
Deemed long-term debt		(5.8)	(12.7)	11.2	9.3	5.3	(3.4)
Short-term debt		7.6	12.0	0.2	(0.1)	7.8	11.8
AFUDC return on Niagara Reinforcement Project	see below*	4.9	4.8	0.1	(0.0)	5.0	4.8
Total return on debt		**$ 273.2**	**$ 288.5**	**$ 2.0**	**$ (3.4)**	**$ 275.2**	**$ 285.1**
Common equity		**$ 344.9**	**$ 379.5**	**$ (10.8)**	**$ (10.8)**	**$ 334.1**	**$ 368.7**

*AFUDC return on Niagara Reinforcement Project							
CWIP		99.1	99.1			99.1	99.1
Deemed long-term debt		4.95%	4.83%			5.01%	4.83%
		4.9	4.8			5.0	4.8

Note 1: As per EB-2008-0272 Decision with Reasons on May 28, 2009, page 54, the deemed long-term rate has been updated to reflect Hydro One's embedded long-term debt rate.

Note 2: The approved rates follow the OEB's November 15, 2012 guidance on cost of capital parameters to reflect the September 2012 Consensus Forecast.

Note 3: The 2014 cost of capital parameters & impacts are based on the October 2012 long-term Consensus Forecast and are for illustrative purposes only. Hydro One will submit a 2014 draft rate order to the OEB reflecting the cost of capital parameters issued by the Board once the September 2013 Consensus Forecast becomes available. At that point the up-to-date cost of capital parameters will be applied to determine the 2014 amounts.

HYDRO ONE NETWORKS INC.
Implementation of OEB Decision on EB-2012-0031
Cost of Long-Term Debt Capital
Test Year (2013)
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 $100 Principal Amount (Dollars)	Effective Cost Rate	Total Amount Outstanding: at 12/31/12 ($Millions)	Total Amount Outstanding: at 12/31/13 ($Millions)	Avg. Monthly Averages ($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	1.0	108.2	99.05	7.01%	109.3	109.3	109.3	7.7	
3	17-Sep-02	6.930%	1-Jun-32	58.0	(2.2)	60.2	103.71	6.64%	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	3-Mar-06	4.640%	3-Mar-16	210.0	1.0	209.0	99.52	4.70%	210.0	210.0	210.0	9.9	
11	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	
12	22-Aug-06	4.640%	3-Mar-16	60.0	0.8	59.2	98.75	4.80%	60.0	60.0	60.0	2.9	
13	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	
14	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	
15	18-Oct-07	5.180%	18-Oct-17	225.0	0.8	224.2	99.63	5.23%	225.0	225.0	225.0	11.8	
16	3-Mar-08	5.180%	18-Oct-17	180.0	(3.1)	183.1	101.73	4.95%	180.0	180.0	180.0	8.9	
17	10-Nov-08	5.000%	12-Nov-13	240.0	1.1	238.9	99.53	5.11%	240.0	0.0	203.1	10.4	
18	14-Jan-09	5.000%	12-Nov-13	130.0	(3.7)	133.7	102.85	4.34%	130.0	0.0	110.0	4.8	
19	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	
20	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	
21	19-Nov-09	3.130%	19-Nov-14	175.0	0.7	174.3	99.63	3.21%	175.0	175.0	175.0	5.6	
22	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	
23	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	
24	13-Sep-10	2.950%	11-Sep-15	150.0	0.6	149.4	99.62	3.03%	150.0	150.0	150.0	4.5	
25	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	
26	26-Sep-11	4.390%	26-Sep-41	205.0	1.3	203.7	99.36	4.43%	205.0	205.0	205.0	9.1	
27	22-Dec-11	4.000%	22-Dec-51	70.0	0.4	69.6	99.48	4.03%	70.0	70.0	70.0	2.8	
28	13-Jan-12	3.200%	13-Jan-22	154.0	0.8	153.2	99.49	3.26%	154.0	154.0	154.0	5.0	
29	22-May-12	3.200%	13-Jan-22	165.0	(1.6)	166.6	100.99	3.08%	165.0	165.0	165.0	5.1	*Note 1*
30	22-May-12	4.000%	22-Dec-51	68.8	0.3	68.4	99.52	4.02%	68.8	68.8	68.8	2.8	*Note 1*
31	31-Jul-12	3.790%	31-Jul-62	52.5	0.3	52.2	99.52	3.81%	52.5	52.5	52.5	2.0	*Note 1*
32	16-Aug-12	3.790%	31-Jul-62	141.0	1.1	139.9	99.21	3.83%	141.0	141.0	141.0	5.4	*Note 1*
33	15-Mar-13	4.016%	15-Mar-43	388.4	1.9	386.4	99.50	4.05%	0.0	388.4	298.8	12.1	*Note 2*
34	15-Jun-13	3.054%	15-Jun-23	388.4	1.9	386.4	99.50	3.11%	0.0	388.4	209.1	6.5	*Note 2*
35	15-Sep-13	2.305%	15-Sep-18	150.0	0.8	149.3	99.50	2.41%	0.0	150.0	46.2	1.1	*Note 2*
36		**Subtotal**							4634.3	5191.1	5131.4	251.9	
37		Treasury OM&A costs										1.6	
38		Other financing-related fees										3.6	
39		**Total**							4634.3	5191.1	5131.4	257.1	5.01%

Note 1: Updated to reflect actual 2012 debt issuance
Note 2: Updated to reflect the forecast coupon rates for 2013 as per the September 2012 Consensus Forecast

HYDRO ONE NETWORKS INC.
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Cost of Long-Term Debt Capital
Test Year (2014)
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 $100 Principal Amount (Dollars)	Effective Cost Rate	Total Amount Outstanding: at 12/31/13 ($Millions)	Total Amount Outstanding: at 12/31/14 ($Millions)	Avg. Monthly Averages ($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	1.0	108.2	99.05	7.01%	109.3	109.3	109.3	7.7	
3	17-Sep-02	6.930%	1-Jun-32	58.0	(2.2)	60.2	103.71	6.64%	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	3-Mar-06	4.640%	3-Mar-16	210.0	1.0	209.0	99.52	4.70%	210.0	210.0	210.0	9.9	
11	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	
12	22-Aug-06	4.640%	3-Mar-16	60.0	0.8	59.2	98.75	4.80%	60.0	60.0	60.0	2.9	
13	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	
14	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	
15	18-Oct-07	5.180%	18-Oct-17	225.0	0.8	224.2	99.63	5.23%	225.0	225.0	225.0	11.8	
16	3-Mar-08	5.180%	18-Oct-17	180.0	(3.1)	183.1	101.73	4.95%	180.0	180.0	180.0	8.9	
17	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	
18	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	
19	19-Nov-09	3.130%	19-Nov-14	175.0	0.7	174.3	99.63	3.21%	175.0	0.0	148.1	4.8	
20	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	
21	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	
22	13-Sep-10	2.950%	11-Sep-15	150.0	0.6	149.4	99.62	3.03%	150.0	150.0	150.0	4.5	
23	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	
24	26-Sep-11	4.390%	26-Sep-41	205.0	1.3	203.7	99.36	4.43%	205.0	205.0	205.0	9.1	
25	22-Dec-11	4.000%	22-Dec-51	70.0	0.4	69.6	99.48	4.03%	70.0	70.0	70.0	2.8	
26	13-Jan-12	3.200%	13-Jan-22	154.0	0.8	153.2	99.49	3.26%	154.0	154.0	154.0	5.0	
27	22-May-12	3.200%	13-Jan-22	165.0	(1.6)	166.6	100.99	3.08%	165.0	165.0	165.0	5.1	*Note 1*
28	22-May-12	4.000%	22-Dec-51	68.8	0.3	68.4	99.52	4.02%	68.8	68.8	68.8	2.8	*Note 1*
29	31-Jul-12	3.790%	31-Jul-62	52.5	0.3	52.2	99.52	3.81%	52.5	52.5	52.5	2.0	*Note 1*
30	16-Aug-12	3.790%	31-Jul-62	141.0	1.1	139.9	99.21	3.83%	141.0	141.0	141.0	5.4	*Note 1*
31	15-Mar-13	4.016%	15-Mar-43	388.4	1.9	386.4	99.50	4.05%	388.4	388.4	388.4	15.7	*Note 2*
32	15-Jun-13	3.054%	15-Jun-23	388.4	1.9	386.4	99.50	3.11%	388.4	388.4	388.4	12.1	*Note 2*
33	15-Sep-13	2.305%	15-Sep-18	150.0	0.8	149.3	99.50	2.41%	150.0	150.0	150.0	3.6	*Note 2*
34	15-Mar-14	4.716%	15-Mar-44	289.8	1.4	288.4	99.50	4.75%	0.0	289.8	223.0	10.6	*Note 3*
35	15-Jun-14	3.754%	15-Jun-24	289.8	1.4	288.4	99.50	3.82%	0.0	289.8	156.1	6.0	*Note 3*
36	15-Sep-14	3.005%	15-Sep-19	289.8	1.4	288.4	99.50	3.11%	0.0	289.8	89.2	2.8	*Note 3*
37		**Subtotal**							5191.1	5885.6	5632.4	266.9	
38		Treasury OM&A costs										1.7	
39		Other financing-related fees										3.3	
40		**Total**							5191.1	5885.6	5632.4	271.9	4.83%

Note 1: Updated to reflect actual 2012 debt issuance
Note 2: Updated to reflect the forecast coupon rates for 2013 as per the September 2012 Consensus Forecast
Note 3: Updated to reflect the forecast coupon rates for 2014 as per the October 2012 long-term Consensus Forecast

Hydro One Networks Inc.
Implementation of OEB Decision on EB-2012-0031

Income Tax

($ millions)	Supporting Reference	Hydro One Proposed 2013	Hydro One Proposed 2014	OEB Decision Impact 2013	OEB Decision Impact 2014	OEB Approved 2013	OEB Approved 2014
Income Taxes	*See supporting details below*	46.4	55.2	(3.3)	(1.8)	43.1	53.4

Income Tax Supporting Details			Hydro One Proposed 2013	Hydro One Proposed 2014	OEB Decision Impact 2013	OEB Decision Impact 2014	OEB Approved 2013	OEB Approved 2014
Rate Base	Exhibit 1.2	a	$ 9,413.5	$ 10,050.9	$ (60.0)	$ (117.3)	$ 9,353.4	$ 9,933.8
Common Equity Capital Structure		b	40.0%	40.0%			40.0%	40.0%
Return on Equity	Exhibit 1.4	c	9.16%	9.44%	-0.23%	-0.16%	8.93%	9.28%
Return on Equity		d = a x b x c	344.9	379.5	(10.8)	(10.8)	334.1	368.7
Regulatory Income Tax		e = l	46.4	55.2	(3.3)	(1.8)	43.1	53.4
Regulatory Net Income (before tax)		f = d + e	391.3	434.8	(14.1)	(12.6)	377.2	422.2
Timing Differences (*Note 1*)		g	(205.4)	(215.4)	6.6	9.6	(198.7)	(205.8)
Taxable Income		h = f + g	185.9	219.4	(7.4)	(3.0)	178.5	216.4
Tax Rate		i	26.5%	26.5%			26.5%	26.5%
Income Tax		j = h x i	49.3	58.1	(2.0)	(0.8)	47.3	57.3
less: Income Tax Credits *(Note 2)*		k	(2.9)	(2.9)	(1.3)	(1.0)	(4.2)	(3.9)
Regulatory Income Tax		l = j + k	46.4	55.2	(3.3)	(1.8)	43.1	53.4

Note 1. Book to Tax Timing Differences	Hydro One Proposed 2013	Hydro One Proposed 2014	OEB Decision Impact 2013	OEB Decision Impact 2014	OEB Approved 2013	OEB Approved 2014
Depreciation	346.7	374.7	(1.7)	(3.3)	345.0	371.5
CCA	(489.7)	(523.2)	7.0	11.8	(482.7)	(511.4)
Other Timing Differences	(62.4)	(66.9)	1.3	1.0	(61.1)	(65.9)
Total Timing Differences	(205.4)	(215.4)	6.6	9.6	(198.7)	(205.8)

Note 2: As per Hydro One's Settlement Agreement approved by the Board on November 8th, 2012, the Apprenticeship Tax Credit is increased by $1.3M in 2013 and $1M in 2013.

Hydro One Networks Inc.

Implementation of OEB Decision on EB-2012-0031

External Revenue

($ millions)	**Supporting Reference**	**Hydro One Proposed 2013**	**Hydro One Proposed 2014**	**OEB Decision Impact 2013**	**OEB Decision Impact 2014**	**OEB Approved 2013**	**OEB Approved 2014**
External Revenue	*See supporting details below*	31.6	31.8	-	4.8	31.6	36.6

External Revenue Details E1-2-1 Page 2		Hydro One Proposed 2013	Hydro One Proposed 2014	OEB Decision Impact 2013	OEB Decision Impact 2014	OEB Approved 2013	OEB Approved 2014
Secondary Land Use		13.2	13.2	-	-	13.2	13.2
Station Maintenance		8.1	8.1	-	-	8.1	8.1
Engineering & Construction		3.0	3.0	-	-	3.0	3.0
Other	*Note 1*	7.3	7.5	-	4.8	7.3	12.3
Total		31.6	31.8	-	4.8	31.6	36.6

Note 1: As per Hydro One's Settlement Agreement approved by the Board on November 8th, 2012, External Revenue is increased by $4.8M in 2014.

Hydro One Networks Inc.
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Export Transmission Service Revenue

($ millions)	**Supporting Reference**	**Hydro One Proposed 2013**	**Hydro One Proposed 2014**	**OEB Decision Impact 2013**	**OEB Decision Impact 2014**	**OEB Approved 2013**	**OEB Approved 2014**
Export Transmission Service Revenue	See Note 1	(31.0)	(30.1)	4.0	(4.0)	(27.0)	(34.1)

	OEB Decision Impact 2013	OEB Decision Impact 2014
Settlement Adjustment *(Note 1)*	4.0	(4.0)

Note 1: Export Tx Service Revenue is reduced by $4M in 2013 but increased by $4M in 2014 to maintain 0% rate increase in 2013.

Hydro One Networks Inc.
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Deferral and Variance Accounts

($ millions)	**Supporting Reference**	**Hydro One Proposed 2013**	**Hydro One Proposed 2014**	**OEB Decision Impact 2013**	**OEB Decision Impact 2014**	**OEB Approved 2013**	**OEB Approved 2014**
Deferral and Variance Accounts	*See supporting details below*	(15.1)	(15.1)	15.1	(15.1)	-	(30.3)

Deferral and Variance Accounts Details F1-1-3		Hydro One Proposed 2013	Hydro One Proposed 2014	OEB Decision Impact 2013	OEB Decision Impact 2014	OEB Approved 2013	OEB Approved 2014
Deferred Export Service Credit		(1.5)	(1.5)	1.5	(1.5)	-	(2.9)
Excess Export Service Revenue		(9.5)	(9.5)	9.5	(9.5)	-	(19.0)
External Secondary Land Use Revenue		(7.3)	(7.3)	7.3	(7.3)	-	(14.6)
External Station Maintenance and E&CS Revenue		(2.6)	(2.6)	2.6	(2.6)	-	(5.2)
Tax Rate Changes		(2.2)	(2.2)	2.2	(2.2)	-	(4.3)
Rights Payments		(0.9)	(0.9)	0.9	(0.9)	-	(1.8)
Long-Term Project Development		2.4	2.4	(2.4)	2.4	-	4.7
Pension Cost Differential		6.4	6.4	(6.4)	6.4	-	12.8
Total	*Note 1*	(15.1)	(15.1)	15.1	(15.1)	-	(30.3)

Note 1: Regulatory Account balance refund is reduced by $15.1M in 2013 but increased by $15.1M in 2014 to maintain 0% rate increase in 2013.

Hydro One Networks Inc.
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Continuity of Revenue Requirement

	Submission		OM&A Adjustments		Capital Expenditures/ISA Adjustments		Tax Credits		Cost of Capital		Revenue Requirement	
	2013	2014	2013	2014	2013	2014	2013	2014	2013	2014	2013	2014
Revenue Requirement												
OM&A	453.3	459.7	(13.0)	(10.0)	0.0	0.0	0.0	0.0	0.0	0.0	440.3	449.7
Depreciation	346.7	374.7	0.0	0.0	(1.7)	(3.3)	0.0	0.0	0.0	0.0	345.0	371.5
Return on debt	273.2	288.5	(0.0)	(0.0)	(1.7)	(3.3)	0.0	0.0	3.7	(0.1)	275.2	285.1
Return on common equity	344.9	379.5	(0.0)	(0.0)	(2.2)	(4.4)	0.0	0.0	(8.6)	(6.4)	334.1	368.7
Income tax	46.4	55.2	(0.0)	(0.0)	1.1	1.5	(1.3)	(1.0)	(3.1)	(2.3)	43.1	53.4
	1464.5	1557.7	(13.0)	(10.0)	(4.4)	(9.5)	(1.3)	(1.0)	(8.0)	(8.8)	1437.7	1528.4
Rate Base	9413.5	10050.9	(0.8)	(0.5)	(59.3)	(116.6)	0.0	0.0	0.0	0.0	9353.4	9933.8
Capital Expenditures	1102.4	1121.5	0.0	0.0	(120.0)	0.0	0.0	0.0	0.0	0.0	982.4	1121.5

Hydro One Networks Inc.

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2013 Revenue Requirement by Rate Pool

	Supporting Exhibit	2013 Rate Pool Revenue Requirement ($ Million)					
		Network	Line Connection	Transformation Connection	Uniform Rates Sub-Total	Wholesale Meter	Total
OM&A	*1.1*	229.9	38.4	100.0	368.2	0.6	368.8
Other Taxes (Grants-in-Lieu)	*Note 1*	45.6	9.5	16.4	71.6	0.0	71.6
Depreciation of Fixed Assets	*1.2*	193.6	35.5	84.2	313.3	0.1	313.4
Capitalized Depreciation	*Note 2*	(6.2)	(1.3)	(2.3)	(9.8)	0.0	(9.8)
Asset Removal Costs	*Note 2*	22.2	4.7	8.3	35.2	0.0	35.3
Other Amortization	*Note 2*	3.9	0.8	1.4	6.1	0.0	6.1
Return on Debt	*1.4*	175.2	36.6	63.2	275.1	0.1	275.2
Return on Equity	*1.4*	212.7	44.5	76.8	334.0	0.1	334.1
Income Tax	*1.5*	27.4	5.7	9.9	43.1	0.0	43.1
Base Revenue Requirement		**904.4**	**174.5**	**357.9**	**1436.9**	**1.0**	**1437.8**
Less Regulatory Asset Credit	*1.8*	0.0	0.0	0.0	0.0	0.0	0.0
Total Revenue Requirement		**904.4**	**174.5**	**357.9**	**1436.9**	**1.0**	**1437.8**
Less Non-Rate Revenues	*1.6*	(19.9)	(3.8)	(7.9)	(31.6)	0.0	(31.6)
Less Export Revenues	*1.7*	(27.0)			(27.0)		(27.0)
Plus LVSG Credit	*6.0*			11.6	11.6		11.6
Total Revenue Requirement for UTR		**857.6**	**170.6**	**361.7**	**1389.9**	**0.9**	**1390.9**
Hydro One Proposed Pool Revenue Requirement	*Note 3*	860.8	172.0	364.8	1397.6	0.9	1398.5

Note 1: Included with OM&A total in Exhibit 1.1. See EB-2012-0031 Exhibit G2, Tab 5, Schedule 1, Page 1.
Note 2: Included with Depreciation total in Exhibit 1.2. See EB-2012-0031 Exhibit G2, Tab 5, Schedule 1, Page 1.
Note 3: See EB-2012-0031 Exhibit G2, Tab 5, Schedule 1, Page 1.

Hydro One Networks Inc.

Implementation of OEB Decision on EB-2012-0031

Summary Charge Determinants
(for Setting Uniform Transmission Rates for January 1, 2013 to December 31, 2013)

	2013 Total MW *
Network	240,274
Line Connection	232,874
Transformation Connection	201,108

** 2013 charge determinants per Exhibit H1, Tab 3, Schedule 1, Table 1, multiplied by 12.*

Hydro One Networks Inc.

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Uniform Transmission Rates and Revenue Disbursement Allocators
(for Period January 1, 2013 to December 31, 2013)

Transmitter	Revenue Requirement ($) *(Note 3, Note 4)*			
	Network	Line Connection	Transformation Connection	Total
FNEI	$3,903,694	$776,807	$1,646,588	$6,327,089
CNPI	$2,845,790	$566,292	$1,200,361	$4,612,443
GLPL	$23,048,170	$4,586,422	$9,721,775	$37,356,367
H1N *(Note 1)*	$857,511,297	$170,638,651	$361,700,360	$1,389,850,308
All Transmitters	$887,308,952	$176,568,172	$374,269,083	$1,438,146,207

Transmitter	Total Annual Charge Determinants (MW) *(Note 3, Note 4)*			
	Network	Line Connection	Transformation Connection	
FNEI	187.120	213.460	76.190	
CNPI	583.420	668.600	668.600	
GLPL	3,445.341	2,461.434	455.652	
H1N *(Note 2)*	240,273.957	232,874.291	201,107.916	
All Transmitters	244,489.838	236,217.785	202,308.358	

Transmitter	Uniform Rates and Revenue Allocators *(Note 4)*			
	Network	Line Connection	Transformation Connection	
Uniform Transmission Rates ($/kW-Month)	**3.63**	**0.75**	**1.85**	
	↓	↓	↓	
FNEI Allocation Factor	**0.00440**	**0.00440**	**0.00440**	
CNPI Allocation Factor	**0.00321**	**0.00321**	**0.00321**	
GLPL Allocation Factor	**0.02598**	**0.02598**	**0.02598**	
H1N Alocation Factor	**0.96641**	**0.96641**	**0.96641**	
Total of Allocation Factors	1.00000	1.00000	1.00000	

Note 1: Hydro One Networks (H1N) 2013 Revenue Requirement per Exhibit 2.0

Note 2: Hydro One Networks (H1N) Charge Determinant per Exhibit 3.0

Note 3: Data for Other Transmitters per Exhibit 4.1

Note 4: Calculated data in shaded cells.

Hydro One Networks Inc.

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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)	$4,612,443	583.420	668.600	668.600	*Note 2*
Great Lakes Power Transmission (GLPT)	$37,356,367	3,445.341	2,461.434	455.652	*Note 3*

Note 1: FNEI Rates Revenue Requirement and Charge Determinants per Board Decision and Order on EB-2009-0387 dated December 9, 2010 and confirmed per email from Board Staff (H. Thiessen).

Note 2: Rates Revenue Requirement and Charge Determinants per Board Decision on RP-2001-0034 dated December 11, 2001 and confirmed per email from Board Staff (H. Thiessen).

Note 3: Rates Revenue Requirement and Charge Determinants per Board Decision on Settlement Agreement for EB-2012-0300 dated October 18, 2012, Draft Rate Order material submitted by GLPT on November 26, 2012 and confirmed per email from Board Staff (H. Thiessen).

2013 ONTARIO UNIFORM TRANSMISSION RATE SCHEDULES

EB-2012-0031

The rate schedules contained herein shall be effective January 1, 2013

Issued: To be determined
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, or has fully contributed toward the costs of, all transformation connection assets associated with that transmission delivery point. The PTS customers that 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, or has fully contributed toward the costs of, 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 the 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 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. 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.

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): $ Per kW of Network Billing Demand[1,2]	**3.63**
Line Connection Service Rate (PTS-L): $ Per kW of Line Connection Billing Demand[1,3]	**0.75**
Transformation Connection Service Rate (PTS-T): $ Per kW of Transformation Connection Billing Demand[1,3,4]	**1.85**

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 embedded generation 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. 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):	$2.00 / 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.
Ontario, Canada

WHOLESALE METER SERVICE
And
EXIT FEE SCHEDULE

Rate Schedule: HON-MET
Issued: To be determined
Ontario Energy Board

APPLICABILITY:

This rate 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) 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 rate 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.

The Wholesale Meter Service rate covered by this schedule shall remain in place until such time as the rate is revised by Order of the Ontario Energy Board.

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 OEB Decision on EB-2012-0031

Wholesale Meter Rate Calculations

	Charge Determinant (Avg # of Meter Points)	Revenue Requirement ($ Million)	OEB Approved Rate * ($/Meter Point/Year)	Hydro One Proposed Rate * ($/Meter Point/Year) (Note 1)
	Note 1	*Note 2*		
	(A)	(B)	(B) / (A)	
2013	118	0.9	8,000	7,900
2014	87	0.7	7,800	7,900
Average 2013 & 2014			7,900	7,900

* Rate is rounded down to the nearest $100

Note 1: Per EB-2012-0031, Exhibit H1, Tab 4, Schedule 1, Table 1.

Note 2: Per Exhibit 2.0

Hydro One Networks Inc.
Implementation of OEB Decision on EB-2012-0031

Low Voltage Switchgear (LVSG) Credit
Effective January 1, 2013

Charge Determinant (MW) *(Note 1)*	**Transformation Pool Revenue Requirement Before LVSG Credit ($M)** *(Note 2)*	**Rate Before LVSG Credit ($/kw/month)**	**Average Monthly NCP Demand for Toronto Hydro and Hydro Ottawa (MW)** *(Note 3)*	**LVS Proportion (%)** *(Note 4)*	**Final LSVG Credit ($M)**
(A)	(B)	(C) = (B)/(A)	(D)	(E)	(F) = (C)x(D)x(E)
201,108	350.1	1.741	2933	19.0%	11.6

Note 1: Per Exhibit 3.0

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

Note 3: Per EB-2012-0031 Exhibit G1, Tab 4, Schedule 1, Table 1

Note 4: See EB-2012-0031 Exhibit G1, Tab 4, Schedule 1, page 1.

Hydro One Networks Inc.
OEB Decision on EB-2012-0031
Deferral and Variance Accounts per Approved Settlement Agreement

The Board's approval of the Settlement Agreement required the Company to continue or establish a number of deferral/variance accounts. The following table includes a list of those accounts:

Account Name	**Settlement Agreement Reference**
LDC CDM and Demand Response Variance Account - New	Page 9, 10, 31 and Appendix A
External Revenue – Partnership Transmission Projects Account - New	Page 11, 12 and Appendix A
Other External Revenues Variance Account - New	Appendix A
Long-Term Transmission Future Corridor Acquisition and Development Account - New	Appendix A
East-West Tie Account	Appendix A
Long-term Project Development OM&A Account	Appendix A
Rights Payment Variance Account	Appendix A
Tax Rate Changes Account	Appendix A
Excess Export Service Revenue Account	Appendix A
External Station Maintenance and E&CS Revenue Variance Account	Appendix A
External Secondary Land Use Revenue Variance Account	Appendix A

As part of the Settlement Agreement Hydro One agreed to discontinue, as of December 31, 2012, both the Impact for Changes in USGAAP Account and the USGAAP Incremental Transition Costs Account. Each account has a zero balance.

Hydro One also will discontinue effective January 1, 2013 the Deferred Export Service Credit Revenue Account and the Long-Term Project Development Costs Account.

For all new accounts identified above, Hydro One has attached the Transmission Accounting Order and the accounting entries that will be used to record the approved deferral and variance.

Transmission Accounting Order – LDC CDM and Demand Response Variance Account

Hydro One Transmission will establish a new revenue variance account, "LDC CDM and Demand Response Variance Account". The account would track the impact of actual CDM and Demand Response results on the Load Forecast and the resulting impact on revenue requirement. The variance would be recorded in a separate sub account of 1508 – Other Regulatory Assets – sub account – CDM Variance Account.

Hydro One Transmission proposes to establish the new sub-account effective January 1, 2013 for the test years 2013 and 2014.

Hydro One Transmission proposes to record the following two elements in the CDM Variance account:

1) CDM Variance

In the variance account, Hydro One Transmission will track the difference between the forecast of 755 MW for 2013 and 1158 MW for 2014 and the actual CDM savings related to the OPA-funded, LDC-delivered programs. Hydro One will use the annual results reported by the OPA in September of each year for the verified results of the previous year in accordance with the CDM Guidelines issued by the Board in EB-2012-0003. Time-of-use savings will not be included in this variance account because they are currently not included in the annual province-wide CDM program results reported by the OPA. The charge determinant variance of the OPA-funded, LDC-delivered program results will be determined using the resulting impact on Ontario Demand and the ratios between the Ontario Demand and the three charge determinants (Network, Transformation Connection, Line Connection) to determine the CDM program impacts on these three charge determinants. The dollar amount of the variance recorded will be based on the three charge determinant variances multiplied by the applicable Uniform Transmission Rates as approved by the Board effective for the 2013 and 2014 test years.

2) Demand Response Variance

In the variance account, Hydro One Transmission will track the actual Demand Response results against the forecast as set out in Exhibit A, Tab 15, Schedule 2, Attachment 1, Appendix A, Table 8 of 836 MW in 2013 and 880 MW in 2014 (net of 317 MW and 410 MW respectfully for 2013 and 2014 already included in CDM program results delivered by LDCs) in this variance account. Hydro One will use annual Demand Response results provided by the OPA each September for results of the previous year in a similar format as the province-wide CDM results delivered by the LDCs. The charge determinant variance of the demand response program results will be determined using the resulting impact on the Ontario Demand and the ratios between the Ontario Demand and the three charge determinants. The dollar amount of the variance will be based on the three charge determinant variances multiplied by the applicable Uniform Transmission Rates as approved by the Board effective for the test years.

Hydro One Transmission will record interest on any balance in the sub-account using the interest rates set by the Board. Simple interest would be calculated on the opening monthly balance of the account until the balance is fully disposed.

Attachment A

Proposed Accounting Entries

	USofA #	Account Description

LDC CDM – Demand Response Variance Account

Cr:	4066	Billed Network Revenue
Cr:	4068	Billed Line Connection Revenue
Cr:	4105	Transmission Charge Revenue
Dr:	1100	Accounts Receivable

To record preliminary recognition of Revenues.

Dr/Cr:	4066	Billed Network Revenue
Dr/Cr:	4068	Billed Line Connection Revenue
Dr/Cr:	4105	Transmission Charge Revenue
Dr/Cr	1508	Other Regulatory Assets – sub Account – LDC CDM and Demand Response Variance Account

To record the variance between Board-approved and actual LDC CDM and Demand Response.

Dr/Cr:	1508	Other Regulatory Assets – Sub account - LDC CDM and Demand Response Variance Account
Cr/Cr:	6035	Other Interest Expense

To record interest improvement on the principal balance of the LDC CDM and Demand Response Variance Account.

Transmission Accounting Order – External Revenue – Partnership Transmission Projects Deferral Account

Hydro One Transmission will establish a new deferral account *External Revenue – Partnership Transmission Projects Deferral Account ("ER-PTPDA").* Hydro One will record costs related to services provided by Hydro One Networks employees to partnership companies, e.g. for work not directly to the benefit of Hydro One Transmission's ratepayers. These costs would be invoiced to the appropriate partnered company, and current transmission revenues equal to the invoiced amount would be recorded in the ER-PTPDA for reduction of future transmission revenue requirements.

The account will be established as Account 1508, Other Regulatory Assets, sub-account 'External Revenue - Partnership Transmission Projects Deferral Account'.

Hydro One Transmission will record interest on any balance in the sub-account using the interest rates set by the Board. Simple interest will be calculated on the opening monthly balance of the account until the balance is fully disposed.

Proposed Accounting Entries

<u>USofA #</u> <u>Account Description</u>

<u>External Revenue – Partnership Transmission Projects Deferral Account</u>

DR 4XXX Transmission OM&A Expense accounts

CR 2205 Accounts Payable

Initial entry to record the OM&A costs incurred by Hydro One in support of the Partnership Transmission Projects.

Dr: 1100 Accounts Receivable - Customers

Cr: 4XXX Transmission Revenue Accounts Range

Standard entry to record Transmission revenue.

Dr: 1200 Accounts Receivable from Associated Companies

Cr: 4235 Miscellaneous Services Revenue

Entry to record amounts billed to affiliate partnership.

Dr: 4XXX Transmission Revenue Accounts Range

Cr: 2405 Other Regulatory Liabilities – sub account "External Revenue – Partnership Transmission Projects deferral account"

To record the Transmission revenues received in respect of amounts to be billed to affiliate for Partnership Transmission Projects in a deferral account for future disposition.

Dr: 6035 Other Interest Expense

Cr: 2405 Other Regulatory Liabilities – sub account "External Revenue – Partnership Transmission Projects deferral account"

To record interest improvement on the principal balance of the "External Revenue – Partnership Transmission Projects deferral account".

Transmission Accounting Order – Other External Revenues Variance Account

Hydro One Transmission will establish a new variance account, "Other External Revenue Variance Account", to record the differences between forecast net other external revenues included in this application and net other external revenues actually received in the test years.

Hydro One Transmission will establish the following new sub-account effective January 1, 2013:

Other External Revenues Variance Account

Other External Revenues include two components: Inergi Royalties and Miscellaneous Revenues.

Inergi Royalties

As a result of the outsourcing agreement with Inergi LP, Hydro One Transmission receives royalty revenue to compensate it for the use of Hydro One's resources by Inergi LP in servicing other third party customers.

Miscellaneous Revenues

Miscellaneous Revenues relate to telecommunications services provided to other Ontario Hydro successor companies such as lease of fibre, special transmission planning studies, customer shortfall payments (e.g. true-ups, temporary bypass), and other miscellaneous revenue. Transfer prices charged to Hydro One Telecom and Hydro One Remote Communities and revenues from the lease of idle transmission lines are also included in Other Miscellaneous Revenue.

Hydro One Transmission will record interest on any balance in the sub-account using the interest rates set by the Board. Simple interest will be calculated on the opening monthly balance of the account until the balance is fully disposed.

Attachment A

Proposed Accounting Entries

	USofA #	Account Description

Other External Revenues Variance Account

Dr:	1105	Accounts Receivable, Merchandising, Jobbing Etc.
Cr:	4235	Miscellaneous Service Revenues

To record preliminary recognition of Other External Revenues.

Dr	4330	Cost and Expenses of Merchandising, Jobbing, etc.
Cr	2205	Accounts Payable

To record preliminary recognition of the Cost of Goods (COGS) sold in respect of Other External Revenues.

Dr/Cr:	4235	Miscellaneous Service Revenues
Dr/Cr:	2405	Other Regulatory Liabilities – Sub-account – Other External Revenues Variance Account

To record the variance between Board-approved and actual Other External Revenues.

Dr/Cr:	4330	Cost and Expenses of Merchandising. Jobbing, etc.
Dr/Cr:	2405	Other Regulatory Liabilities – Sub-account – Other External Revenues Variance Account

To record the variance between Board-approved and actual Other External Revenues - COGS.

Dr/Cr:	1508	Other Regulatory Assets – Sub account - Other External Revenues Variance Account
Dr/Cr:	6035	Other Interest Expense

Transmission Accounting Order – Long-Term Transmission Future Corridor Acquisition and Development Account

Hydro One Transmission will establish a new deferral account - the Long-Term Transmission Future Corridor Acquisition and Development Account. Hydro One will record transmission planning and study costs associated with preliminary corridor routing considerations for new transmission infrastructure in this account.

The account shall be established as Account 1508, Other Regulatory Assets, sub-account 'Long-Term Transmission Future Corridor Acquisition and Development Account'.

Hydro One Transmission will record interest on any balance in the sub-account using the interest rates set by the Board. Simple interest will be calculated on the opening monthly balance of the account until the balance is fully disposed.

Detailed accounting entries for the above two sub-accounts are attached as Attachment 1.

Proposed Disposition of the Accounts

Hydro One Transmission will request disposition of the actual audited regulatory account values plus forecast interest on the principal balances at a future transmission rates application.

Proposed Accounting Entries

<u>USofA #</u> <u>Account Description</u>

<u>Long-Term Transmission Future Corridor Acquisition and Development Account</u>

Dr: 48XX Operational Transmission Expense account range

Cr: 2205 Accounts Payable

Initial entry to record OM&A costs incurred for Long-Term Transmission Future Corridor Acquisition and Development costs.

Dr: 1508 Other Regulatory Assets – Sub account "Long-Term Transmission Future Corridor Acquisition and Development Account"

Cr: 48XX Operational Transmission Expense account range

To record incremental costs incurred for supporting Long-Term Transmission Future Corridor Acquisition and Development activities in a d eferral account for future recovery.

Dr: 1508 Other Regulatory Assets – Sub account "Long-Term Transmission Future Corridor Acquisition and Development Account"

Dr: 6035 Other Interest Expense

To record interest improvement on t he principal balance of the "Long-Term Transmission Future Corridor Acquisition and Development Account".

EB-2012-0031 – SETTLEMENT AGREEMENT

EB-2012-0031

SETTLEMENT AGREEMENT

Hydro One Networks Inc.
Test year 2013 and 2014 Transmission Rates

November 6, 2012

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Hydro One Networks Inc.
Test Year 2013 and 2014 Transmission Rates
EB-2012-0031

SETTLEMENT AGREEMENT

PREAMBLE:

This Settlement Agreement is filed with the Ontario Energy Board ("the Board") in connection with the application by Hydro One Networks Inc. ("Hydro One") for an Order or Orders approving the revenue requirement and customer rates for the transmission of electricity to be implemented January 1, 2013 and January 1, 2014.

Further to the Board's Procedural Order No. 3 dated and issued October 1, 2012, a Settlement Conference was held on October 23, 24, 25 and 26, 2012 in accordance with the *Ontario Energy Board Rules of Practice and Procedure* ("Rules") and the Board's Settlement Conference Guidelines ("Guidelines").

Hydro One and the following intervenors ("the parties") participated in the settlement conference:

Association of Major Power Consumers in Ontario ("AMPCO")
Association of Power Producers of Ontario ("APPrO")
Building Owners and Managers Association Toronto ("BOMA")
Canadian Manufacturers & Exporters ("CME")
Consumers Council of Canada ("CCC")
Energy Probe Research Foundation ("EP")
Goldcorp
London Property Management Association ("LPMA")
Pollution Probe ("PP") – participation subsequently withdrawn from proceeding
Power Workers' Union ("PWU")
School Energy Coalition ("SEC")
Vulnerable Energy Consumers Coalition ("VECC")

Ontario Energy Board staff also participated in the settlement conference, but are not a party to this settlement agreement.

Outlined below are the positions of the parties following the settlement conference. The settlement agreement follows the format of the Approved Issues List for ease of reference. The issues are characterized as follows:

> **Settled:** If the settlement agreement is accepted by the Board, the parties will not adduce any evidence or argument during the oral hearing as the Applicant and those intervenors who take any position on the issue agree to the proposed settlement;
>
> **Partially Settled:** If the settlement agreement is accepted by the Board, the parties will only adduce evidence and argument during the hearing on portions of the issues as the Applicant and those intervenors who take any position on the issue were able to agree on some, but not all, aspects of the particular issue; and
>
> **Not Settled:** The Applicant and those intervenors who take a position on the issue will adduce evidence and argument at the hearing on the issue as the parties were unable to reach agreement.

For ease of reference, the following outlines the status of the issues as outlined in the Settlement Agreement:

Settled: Issue completely resolved. Parties will not adduce evidence or argument at the hearing.	**Partially Settled:** Issue partially resolved. Parties will adduce evidence and argument at hearing on certain portions of the issue.	**Not Settled:** Issue not resolved. Evidence to be adduced and argument presented on entirety of issue.
# issues settled: 23	# issues partially settled: 1	# issues not settled: 1

The positions taken by the various parties on each of the settled issues are identified throughout the Settlement Agreement. A party who is noted as taking no position on an issue may or may not have participated in the discussion on that particular issue and takes no position on the settlement reached or on the sufficiency of the evidence filed to date.

The Settlement Agreement provides a brief description of each of the settled issues, together with references to the evidence filed. The supporting parties to each settled issue agree that the evidence in respect of that settled issue, as supplemented in some instances by additional information recorded in the proposal, supports the proposed settlement. In addition, the supporting parties agree that the evidence filed in support of each settled issue and the additional information as recorded herein contains sufficient detail, rationale and quality of information to allow the Board to make findings in keeping with the settlement reached. The Intervenors are relying on the accuracy and completeness of the Appendices in entering into this Agreement.

The Board's Settlement Conference Guidelines (p.3) require the parties to consider whether a settlement agreement should include an adjustment mechanism for any settled issue that may be affected by external factors. Hydro One and the other parties who participated in the Settlement Conference consider that no settled issues require such an adjustment mechanism other than those expressly set forth in this settlement agreement.

None of the parties can withdraw from the Settlement Agreement except in accordance with Rule 32 of the Ontario Energy Board's *Rules of Practice and Procedure*. Finally, unless stated otherwise, the settlement of any particular issue in this proceeding and the positions of the parties in this Proposal are without prejudice to the rights of parties to raise the same issue and/or to take any position thereon in any other proceedings, unless explicitly stated otherwise.

The parties agree that the remaining unsettled issue will be dealt with during the oral phase of this proceeding, subject to further direction from the Board. The outstanding issue relating to rate base is regarding the net book value (NBV) of Red Lake TS. Goldcorp is the only intervenor with concerns. Hydro One proposes that this issue be dealt with as directed by the Board.

The parties agree that all positions, negotiations and discussion of any kind whatsoever that took place during the Settlement Conference and all documents exchanged during the conference that were prepared to facilitate settlement discussions are strictly confidential and without prejudice, and inadmissible unless relevant to the resolution of any ambiguity that subsequently arises with respect to the interpretation of any provision of this Settlement Agreement.

It is fundamental to the agreement of the parties that none of the provisions of this Settlement Agreement are severable. If the Board does not, prior to the commencement of the hearing of the evidence in this proceeding, accept the provisions of the Settlement Agreement in their entirety there is no Settlement Agreement unless the parties agree to the contrary.

For the Board's ease of reference, a List of Approvals Sought is attached as Appendix A.

OVERVIEW:

The parties were able to reach agreement on most issues, including Operations, Maintenance & Administration (OM&A) costs, Capital Expenditures and Rate Base, and all other Revenue Requirement related issues. The parties were unable to reach agreement on the appropriate Export Transmission rate for 2013 and 2014 and have therefore agreed that this issue should proceed to the oral hearing, subject to further direction from the Board

Overall rate impacts were a guiding principle that led to the Settlement Agreement. Hydro One filed a rate application seeking a 0.6% increase in 2013 transmission rates and a 9.1% increase in 2014 transmission rates. The parties efforts were focused on determining an appropriate Revenue Requirement and resulting rate levels for 2013 and 2014, while balancing Hydro One's need to continue to safely and reliably operate and to fund its expanding work program.

The overall financial impact of the Settlement Agreement is to reduce the revenue requirement from $1,464.5M to $1,445.7M in 2013 and $1,557.7M to $1,537.2M in 2014 or by $18.7M and $20.5M respectively. The resulting overall rate impact is a 0% rate increase in 2013 and 7.1% rate increase in 2014, down from 0.6% and 9.1% rate increases in the Application. The financial rate impact calculation is attached to this Settlement Agreement as Appendix B.

As noted above, all parties agree that the Settlement Agreement is a broad package proposal. Thus, individual components of the Settlement Agreement ought not be considered or reviewed in isolation. All parties agree the overall package of the Settlement Agreement represents a fair and reasonable agreement that balances the interests of all stakeholders including the ratepayers, the intervenors, concerns previously noted by the Board and Hydro One's needs in order to run a safe and reliable transmission system.

Only one issue remains outstanding – the Export Transmission Service (ETS) rate to be charged. Several parties have filed evidence regarding the appropriate ETS rate including the IESO, APPrO and Hydro-Québec Energy Marketing Inc. (HQ). Hydro One is neutral regarding this issue.

The particulars of the Settlement Agreement are detailed below by issue as set out in the Issues List.

GENERAL

1. Has Hydro One responded appropriately to all relevant Board directions from previous proceedings?

   Settled. For the purposes of reaching a settlement, the parties accept that the Applicant has appropriately responded to all directives from prior proceedings. Particulars, where relevant, are discussed below in the context of other issues.

   Evidence: The evidence in relation to this issue includes the following:

A-15-2	Business Load Forecast and Methodology
A-15-2 Appendix A	Monthly Econometric Model
A-15-2 Appendix B	Annual Econometric Model
A-15-2 Appendix C	End-Use Model

A-15-2 Appendix D	Historical Ontario Demand and Charge Determinant Data
A-15-2 Appendix E	Consensus Forecast for Ontario GDP and Housing Starts
A-15-2 Appendix F	Forecast Accuracy
A-15-2 Attachment 1	Incorporating Conservation and Demand Management Impacts in the Load Forecast
A-19-1	Summary of Board Directives and Undertakings from Previous Proceedings
C1-3-3	Development OM&A
C1-3-3 Attachment 1	Smart Grid Development Report
C1-5-2	Compensation, Wages, Benefits
C1-5-2 Attachment 1	Mercer Compensation Cost Benchmarking Study
C1-5-2 Attachment 2	Payroll Table 2009 to 2012
C1-7-2	Overhead Capitalization Rate
C1-7-2 Attachment 1	Review of Overhead Capitalization Rates (Transmission) - 2013/2014
C1-7-2 Attachment 2	Review of Overhead Capitalization Policy
D1-3-3	Development Capital
D1-3-3 Appendix A	Summary of Development Capital Projects in Excess of $3 Million
D1-3-3 Appendix B	OPA Supporting Material for Oshawa TS
D1-3-3 Appendix C	OPA Document on Southwestern Ontario Reactive Compensation Milton SVC dated March 2012
D1-3-3 Appendix D	Letter from OPA dated June 30, 2011
D1-3-3 Appendix E	Letter from OPA dated March 8, 2012
D1-3-3 Appendix F	Letter from OPA dated August 7, 2012
D2-2-3	Investment Summary for Programs/Projects in excess of $3M
F1-1-1	Regulatory Accounts
H1-5-1	Rates for Export Transmission Service
I-1-1.01 Staff 1	OEB Interrogatory #1

Supporting Parties: EP, SEC, VECC, LPMA, BOMA, CCC, CME, PWU, AMPCO

Parties taking no position: Goldcorp, APPrO

2. Is the overall increase in 2013 and 2014 revenue requirement reasonable?

   Settled. For the purposes of reaching a settlement, the parties agree that the settled revenue requirement before adjustment of $1,445.7M in 2013 and $1,537.2M in 2014 is reasonable. The parties are further in agreement that after adjusting for External Revenues, the Export Revenue Credit, transmission riders and low voltage switch gear items, the Rates Revenue Requirement resulting from this settlement agreement of $1,390.3M in 2013 and $1457.0M in 2014 is reasonable. This represents a decrease of $8.2M in 2013 and a decrease of $36.2M in 2014 from the application as originally filed. The resulting rate increase will be 0.0% in 2013 and 7.1% in 2014 versus 0.6% and 9.1% as proposed in the application.

   The parties agree that the revenue requirement will be adjusted to reflect the Board's latest cost of capital parameters for the 2013 and 2014 test years in the final rate order as described in Exhibit B1, Tab 1, Schedule 1.

   As of December 31, 2012, there will be a regulatory asset balance of ($30.3M). Hydro One initially proposed refunding that asset balance equally over each of the test years. In an effort to strive for a 0% increase in transmission rates for 2013, the parties agreed to utilize the regulatory asset balance as a balancing item to ensure that the increase in 2013 remains at 0.0% after other adjustments are made (such as for the latest cost of capital parameters). Any remaining balance will be refunded to customers in 2014. The precise amount to be refunded in the test years will be reflected in the final rate order.

The table below summarizes the proposal:

Hydro One Transmission Revenue Requirement Settlement Agreement

	2012	2013	2014
OM&A		440.3	449.7
Depreciation		345.0	371.5
Income tax		46.2	55.7
Cost of capital		614.2	660.4
Revenue requirement	**1,418.4**	**1,445.7**	**1,537.2**
	5.4%	1.9%	6.3%
Less: External revenues		-31.6	-36.6
Less: Export revenue credit		-31.0	-30.1
Less: "Tx Riders"		-4.5	-25.7
Add: LVSG		11.7	12.2
Rates Revenue Requirement	**1,385.1**	**1,390.3**	**1,457.0**
		0.4%	4.8%
Estimated impact of load reduction		0.4%	-2.3%
Assumed Rate Impact		**0.0%**	**7.1%**

Hydro One's application as filed assumes that the ETS rate would remain at $2/MWh. A number of alternative rates are being proposed. Should the Board approve a change in the ETS rate, the parties agree that the full impact of the change will be tracked in the existing Board approved Excess Export Services Revenue Account for disposition in a future rate application.

Evidence: The evidence in relation to this issue includes the following:

E1-1-1	Revenue Requirement
E2-1-1	Calculation of Revenue Requirement
I-2-1.01 Staff 2	OEB Interrogatory #2
I-2-1.02 Staff 3	OEB Interrogatory #3

I-2-1.03 Staff 4	OEB Interrogatory #4
I-2-1.04 Staff 5	OEB Interrogatory #5
I-2-1.05 Staff 6	OEB Interrogatory #6
I-2-1.06 Staff 7	OEB Interrogatory #7
I-2-1.07 Staff 8	OEB Interrogatory #8
I-2-1.08 Staff 9	OEB Interrogatory #9
I-2-1.09 Staff 10	OEB Interrogatory #10
I-2-1.10 Staff 11	OEB Interrogatory #11
I-2-1.11 Staff 12	OEB Interrogatory #12
I-2-1.12 Staff 13	OEB Interrogatory #13
I-2-1.13 Staff 14	OEB Interrogatory #14
I-2-1.14 Staff 15	OEB Interrogatory #15
I-2-2.01 LPMA 1	LPMA Interrogatory #1
I-2-3.01 EP 1	Energy Probe Interrogatory #1
I-2-3.02 EP 2	Energy Probe Interrogatory #2
I-2-3.03 EP 3	Energy Probe Interrogatory #3
I-2-3.04 EP 4	Energy Probe Interrogatory #4
I-2-3.05 EP 5	Energy Probe Interrogatory #5
I-2-3.06 EP 6	Energy Probe Interrogatory #6
I-2-3.07 EP 7	Energy Probe Interrogatory #7
I-2-5.01 VECC 1	VECC Interrogatory #1
I-2-5.02 VECC 2	VECC Interrogatory #2
I-2-5.03 VECC 3	VECC Interrogatory #3
I-2-5.04 VECC 4	VECC Interrogatory #4
I-2-5.05 VECC 5	VECC Interrogatory #5
I-2-5.06 VECC 6	VECC Interrogatory #6
I-2-5.07 VECC 7	VECC Interrogatory #7
I-2-5.08 VECC 8	VECC Interrogatory #8
I-2-5.09 VECC 9	VECC Interrogatory #9
I-2-5.10 VECC 10	VECC Interrogatory #10
I-2-5.11 VECC 11	VECC Interrogatory #11
I-2-5.12 VECC 12	VECC Interrogatory #12
I-2-5.13 VECC 13	VECC Interrogatory #13
I-2-5.14 VECC 14	VECC Interrogatory #14
I-2-8.01 PWU 1	PWU Interrogatory #1
I-2-9.01 SEC 1	SEC Interrogatory #1
I-2-9.02 SEC 2	SEC Interrogatory #2
I-2-9.04 SEC 4	SEC Interrogatory #4
I-2-9.05 SEC 5	SEC Interrogatory #5
I-2-9.06 SEC 6	SEC Interrogatory #6
I-2-10.01 CCC 1	CCC Interrogatory #1
I-2-10.02 CCC 2	CCC Interrogatory #2

I-2-10.03 CCC 3	CCC Interrogatory #3
I-2-10.04 CCC 4	CCC Interrogatory #4
I-2-10.05 CCC 5	CCC Interrogatory #5
I-2-14.01 CME 1	CME Interrogatory #1
JT1.1 TCR Staff 4	OEB Technical Conference Response #4
KT1.12	Undertaking Response #12

Supporting Parties: EP, SEC, VECC, LPMA, BOMA, CCC, CME, AMPCO

Parties taking no position: PWU, Goldcorp, APPrO

LOAD FORECAST AND REVENUE FORECAST

3. Is the load forecast and methodology appropriate and have the impacts of Conservation and Demand Management initiatives been suitably reflected?

   Settled. For the purposes of reaching a settlement, all parties accept Hydro One's load forecast as set out in Exhibit A, Tab 15, Schedule 2. Hydro One continues to apply the same forecasting methodology previously approved by the Board in EB-2010-0002 which the parties agree remains appropriate.

   The impacts of CDM and Demand Response and how they are reflected in the load forecast were the primary areas of concern for some intervenors. The Board had some concern in this area as well in prior proceedings. In EB-2010-0002, Hydro One's last Transmission Rates Application, the Board directed Hydro One to work with the OPA to devise a means of effectively and accurately measuring CDM impacts. Hydro One has done so and has relied upon the latest CDM and Demand Response forecasts in its load forecast for the test years.

   There remains some concern on the part of certain intervenors about the accuracy and reliability of the CDM and Demand Response forecasts prepared by the OPA. In order to address those concerns, Hydro One has agreed to establish a new variance account to track the impact of actual CDM and Demand Response results on the Load Forecast and the resulting impact on revenue requirement.

   Hydro One agrees to set up a variance account to track the difference between the forecast of 755MW for 2013 and 1158MWfor 2014 and the actual CDM savings related to the OPA-funded, LDC-delivered programs. Hydro One will use the annual results reported by the OPA in September of each year for the verified results of the previous year in accordance with the CDM Guidelines issued by the Board in EB-2012-0003. Time-of-use savings will not be included in this variance account because they are currently not included in the annual province-wide CDM program results reported by the OPA.

Hydro One also agreed to track the actual Demand Response results against the forecast as set out in Exhibit A, Tab 15, Schedule 2, Attachment 1, Appendix A, Table 8 of 836MW in 2013 and 880MW2014 (net of 317MW and 410MW respectfully for 2013 and 2014 already included in CDM program results delivered by LDCs) in this variance account. Hydro One will use annual Demand Response results provided by the OPA each September for results of the previous year in a similar format as the province-wide CDM results delivered by the LDCs.

The disposition of the balance in the LDC CDM and Demand Response Variance Account will be part of a future Rate Application.

Evidence: The evidence in relation to this issue includes the following:

A-6-1	Compliance with OEB Filing Requirements for Electricity Transmitters
A-15-1	Economic Indicators
A-15-2	Business Load Forecast and Methodology
A-15-2 Appendix A	Monthly Econometric Model
A-15-2 Appendix B	Annual Econometric Model
A-15-2 Appendix C	End-Use Model
A-15-2 Appendix D	Historical Ontario Demand and Charge Determinant Data
A-15-2 Appendix E	Consensus Forecast for Ontario GDP and Housing Starts
A-15-2 Appendix F	Forecast Accuracy
A-15-2 Attachment 1	Incorporating Conservation and Demand Management Impacts in the Load Forecast
I-3-1.01 Staff 16	OEB Interrogatory #16
I-3-1.02 Staff 17	OEB Interrogatory #17
I-3-1.03 Staff 18	OEB Interrogatory #18
I-3-1.04 Staff 19	OEB Interrogatory #19
I-3-1.05 Staff 20	OEB Interrogatory #20
I-3-1.06 Staff 21	OEB Interrogatory #21
I-3-1.07 Staff 22	OEB Interrogatory #22
I-3-2.01 LPMA 2	LPMA Interrogatory #2
I-3-2.02 LPMA 3	LPMA Interrogatory #3
I-3-2.03 LPMA 4	LPMA Interrogatory #4
I-3-2.04 LPMA 5	LPMA Interrogatory #5
I-3-3.01 EP 8	Energy Probe Interrogatory #8
I-3-3.02 EP 9	Energy Probe Interrogatory #9
I-3-3.03 EP 10	Energy Probe Interrogatory #10
I-3-5.01 VECC 15	VECC Interrogatory #15
I-3-5.02 VECC 16	VECC Interrogatory #16
I-3-5.03 VECC 17	VECC Interrogatory #17
I-3-5.04 VECC 18	VECC Interrogatory #18
I-3-5.05 VECC 19	VECC Interrogatory #19

I-3-5.06 VECC 20	VECC Interrogatory #20
I-3-5.07 VECC 21	VECC Interrogatory #21
I-3-5.08 VECC 22	VECC Interrogatory #22
I-3-5.09 VECC 23	VECC Interrogatory #23
I-3-5.10 VECC 24	VECC Interrogatory #24
I-3-5.11 VECC 25	VECC Interrogatory #25
I-3-13.01 AMPCO 1	AMPCO Interrogatory #1
I-3-13.02 AMPCO 2	AMPCO Interrogatory #2
I-3-13.03 AMPCO 3	AMPCO Interrogatory #3
JT1.2 TCR EP1	Energy Probe Technical Conference Response #1
KT1.6	Undertaking Response #6
KT1.7	Undertaking Response #7
KT1.8	Undertaking Response #8

Supporting Parties: EP, SEC, VECC, LPMA, BOMA, CCC, CME, PWU, AMPCO

Parties taking no position: Goldcorp, APPrO

4. Are Other Revenue (including export revenue) forecasts appropriate?

Settled. For the purposes of reaching a settlement, the parties agree that the 2013 external revenue forecast of $31.6M is appropriate. Some intervenors were concerned that the forecast for external revenues in 2014 was too low based on historical average actual external revenues. Accordingly, as part of the settlement, Hydro One agreed to increase the forecast for external revenues in 2014 by $4.8M to $36.6M from $31.8M in order to reflect the historical average of actual revenues in the previous three years. The table below summarizes the proposed change:

External Revenue ($M)	***2013***	***2014***
Filed Evidence	31.6	31.8
Settlement Agreement	31.6	36.6
Change Proposed	-	4.8

Three of the four inputs (Secondary Land Use, Station Maintenance and Engineering and Project Delivery) into the overall external revenue forecasts are currently tracked in symmetrical variance accounts. The parties agreed that all inputs into the external revenues should be tracked in a variance account. Thus, Hydro One agreed to create a new symmetrical variance account to track any differences in Other External Revenue.

As noted above, the parties have also agreed, that Hydro One will track any changes in ETS Revenue in the Excess Export Services Revenue Account should the Board approve a change to the current ETS rate of $2.00/MWh.

Evidence: The evidence in relation to this issue includes the following:

E1-2-1	External Revenues
I-4-2.01 LPMA 6	LPMA Interrogatory #6
I-4-2.02 LPMA 7	LPMA Interrogatory #7
I-4-2.03 LPMA 8	LPMA Interrogatory #8
I-4-2.04 LPMA 9	LPMA Interrogatory #9
I-4-2.05 LPMA 10	LPMA Interrogatory #10
I-4-2.06 LPMA 11	LPMA Interrogatory #11
I-4-5.01 VECC 26	VECC Interrogatory #26
I-4-5.02 VECC 27	VECC Interrogatory #27
I-4-5.03 VECC 28	VECC Interrogatory #28
I-4-5.04 VECC 29	VECC Interrogatory #29
I-4-9.01 SEC 7	SEC Interrogatory #7
I-4-10.01 CCC 6	CCC Interrogatory #6
I-4-10.02 CCC 7	CCC Interrogatory #7
KT1.23	Undertaking Response #23

Supporting Parties: EP, SEC, VECC, LPMA, BOMA, CCC, CME, PWU, AMPCO

Parties taking no position: Goldcorp, APPrO

OPERATIONS, MAINTENANCE AND ADMINISTRATION COSTS

Overall OM&A Settlement and its Rationale

All issues relating to Operations, Maintenance and Administration costs have been settled. The parties focused on overall spending levels for OM&A expenditures rather than focusing on any one particular aspect of those costs. The rationale for the settlement of Issues 5, 6 and 7 is outlined below.

Hydro One's application forecast OM&A expenditures of $453.3M and $459.7M in 2013 and 2014 respectively.

In order to address the concerns expressed by intervenors, balanced against Hydro One's needs to effectively operate the transmission business, combined with ongoing productivity initiatives being undertaken, Hydro One agreed to reduce 2013 spending levels by $13.0M from $453.3M to $440.3M. OM&A spending for 2014 will be reduced by $10M from $459.7M to $449.7M. The parties agree that these reduced proposed spending levels are appropriate.

The table below summarizes the proposed changes:

OM&A ($M)	***2013***	***2014***
Filed Evidence	453	460
Settlement Agreement	440	450
Change Proposed	-13	-10

5. Are the proposed spending levels for Sustaining, Development and Operations OM&A in 2013 and 2014 appropriate, including consideration of factors such as system reliability and asset condition?

Settled. See rationale above.

Evidence: The evidence in relation to this issue includes the following:

A-15-6	Work Execution Strategy
C1-1-1	Cost of Service Summary
C1-2-1	Sustaining Investment Structure
C1-2-2	Transmission Assets and Sustaining Investment Overview
C1-2-2 Appendix A	Hydro One Transmission Asset Descriptions
C1-3-1	Summary of OM&A Expenditures
C1-3-2	Sustaining OM&A
C1-3-3	Development OM&A
C1-3-3 Attachment 1	Smart Grid Development Report
C1-3-4	Operations OM&A
C1-3-5	Customer Care OM&A
C1-4-1	Summary of Shared Services – OM&A
C1-4-2	Common Corporate Functions & Services and Other OM&A
C1-4-3	Shared Services OM&A – Asset Management
C1-4-4	Shared Services OM&A – Information Technology
C1-4-4 Attachment 1	H1 Telecom Inc. Services Review and Benchmarking
C1-4-5	Shared Services OM&A – Cornerstone
C1-4-6	Shared Services OM&A – Cost of Sales - External Work
C1-4-7	Property Taxes
C2-1-1	Cost of Service

C2-2-1	Comparison of OM&A Expense by Major Category
I-5-1.01 Staff 23	OEB Interrogatory #23
I-5-1.02 Staff 24	OEB Interrogatory #24
I-5-1.03 Staff 25	OEB Interrogatory #25
I-5-1.04 Staff 26	OEB Interrogatory #26
I-5-1.05 Staff 27	OEB Interrogatory #27
I-5-1.06 Staff 28	OEB Interrogatory #28
I-5-1.07 Staff 29	OEB Interrogatory #29
I-5-1.08 Staff 30	OEB Interrogatory #30
I-5-1.09 Staff 31	OEB Interrogatory #31
I-5-1.10 Staff 32	OEB Interrogatory #32
I-5-1.11 Staff 33	OEB Interrogatory #33
I-5-1.12 Staff 34	OEB Interrogatory #34
I-5-1.13 Staff 35	OEB Interrogatory #35
I-5-2.01 LPMA 12	LPMA Interrogatory #12
I-5-3.01 EP 11	Energy Probe Interrogatory #11
I-5-3.02 EP 12	Energy Probe Interrogatory #12
I-5-3.03 EP 13	Energy Probe Interrogatory #13
I-5-3.04 EP 14	Energy Probe Interrogatory #14
I-5-3.05 EP 15	Energy Probe Interrogatory #15
I-5-3.06 EP 16	Energy Probe Interrogatory #16
I-5-3.07 EP 17	Energy Probe Interrogatory #17
I-5-3.08 EP 18	Energy Probe Interrogatory #18
I-5-3.09 EP 19	Energy Probe Interrogatory #19
I-5-3.10 EP 20	Energy Probe Interrogatory #20
I-5-3.11 EP 21	Energy Probe Interrogatory #21
I-5-8.01 PWU 2	PWU Interrogatory #2
I-5-8.02 PWU 3	PWU Interrogatory #3
I-5-8.03 PWU 4	PWU Interrogatory #4
I-5-8.04 PWU 5	PWU Interrogatory #5
I-5-8.05 PWU 6	PWU Interrogatory #6
I-5-8.06 PWU 7	PWU Interrogatory #7
I-5-8.07 PWU 8	PWU Interrogatory #8
I-5-8.08 PWU 9	PWU Interrogatory #9
I-5-8.09 PWU 10	PWU Interrogatory #10
I-5-8.10 PWU 11	PWU Interrogatory #11
I-5-8.11 PWU 12	PWU Interrogatory #12
I-5-8.12 PWU 13	PWU Interrogatory #13
I-5-8.13 PWU 14	PWU Interrogatory #14
I-5-8.14 PWU 15	PWU Interrogatory #15
I-5-8.15 PWU 16	PWU Interrogatory #16

I-5-9.01 SEC 8	SEC Interrogatory #8
I-5-9.02 SEC 9	SEC Interrogatory #9
I-5-9.03 SEC 10	SEC Interrogatory #10
I-5-9.04 SEC 11	SEC Interrogatory #11
I-5-9.05 SEC 12	SEC Interrogatory #12
I-5-9.06 SEC 13	SEC Interrogatory #13
I-5-9.07 SEC 14	SEC Interrogatory #14
I-5-9.08 SEC 15	SEC Interrogatory #15
I-5-9.09 SEC 16	SEC Interrogatory #16
I-5-9.10 SEC 17	SEC Interrogatory #17
I-5-10.01 CCC 8	CCC Interrogatory #8
I-5-10.02 CCC 9	CCC Interrogatory #9
I-5-10.03 CCC 10	CCC Interrogatory #10
I-5-10.04 CCC 11	CCC Interrogatory #11
I-5-10.05 CCC 12	CCC Interrogatory #12
I-5-10.06 CCC 13	CCC Interrogatory #13
I-5-10.07 CCC 14	CCC Interrogatory #14
I-5-10.08 CCC 15	CCC Interrogatory #15
I-5-12.01 THESL 1	THESL Interrogatory #1
JT1.1 TCR PWU 5	PWU Technical Conference Response #5
JTI.1 TCR Staff 8	OEB Technical Conference Response #8
JT1.1 TCR Staff 10	OEB Technical Conference Response #10
KT1.13	Undertaking Response #13
KT1.14	Undertaking Response #14
KT1.15	Undertaking Response #15
KT1.24	Undertaking Response #24
KT1.26	Undertaking Response #26
KT1.36	Undertaking Response #36

Supporting Parties: EP, SEC, VECC, LPMA, BOMA, CCC, CME, AMPCO

Parties taking no position: PWU, Goldcorp, APPrO

6. Are the proposed spending levels for Shared Services and Other O & M in 2013 and 2014 appropriate?

Settled. See rationale above.

Evidence: The evidence in relation to this issue includes the following:

C1-3-5	Customer Care OM&A
C1-4-1	Summary of Shared Services – OM&A

C1-4-2	Shared Services – Common Corporate Functions & Services and Other OM&A
C1-4-3	Shared Services OM&A– Asset Management
C1-4-4	Shared Services OM&A – Information Technology
C1-4-4 Attachment 1	H1 Telecom Inc. Services Review and Benchmarking
C1-4-5	Shared Services OM&A – Cornerstone
C1-4-6	Shared Services OM&A – Cost of Sales - External Work
C1-4-7	Property Taxes
I-6-1.01 Staff 36	OEB Interrogatory #36
I-6-1.02 Staff 37	OEB Interrogatory #37
I-6-1.03 Staff 38	OEB Interrogatory #38
I-6-3.01 EP 22	Energy Probe Interrogatory #22
I-6-3.02 EP 23	Energy Probe Interrogatory #23
I-6-3.03 EP 24	Energy Probe Interrogatory #24
I-6-3.04 EP 25	Energy Probe Interrogatory #25
I-6-3.05 EP 26	Energy Probe Interrogatory #26
I-6-5.01 VECC 30	VECC Interrogatory #30
I-6-5.02 VECC 31	VECC Interrogatory #31
I-6-9.01 SEC 19	SEC Interrogatory #19
I-6-10.01 CCC 16	CCC Interrogatory #16
I-6-10.02 CCC 17	CCC Interrogatory #17
I-6-10.03 CCC 18	CCC Interrogatory #18
I-6-10.04 CCC 19	CCC Interrogatory #19
I-6-10.05 CCC 20	CCC Interrogatory #20
I-6-10.06 CCC 21	CCC Interrogatory #21
I-6-10.07 CCC 22	CCC Interrogatory #22

Supporting Parties: EP, SEC, VECC, LPMA, BOMA, CCC, CME, AMPCO

Parties taking no position: PWU, Goldcorp, APPrO

7. Are the 2013/14 Human Resources related costs (wages, salaries, benefits, incentive payments, labour productivity and pension costs) including employee levels appropriate? Has Hydro One demonstrated improvements in efficiency and value for dollar associated with its compensation costs?

   Settled. See rationale above.

   Evidence: The evidence in relation to this issue includes the following:

A-17-1	Cost Efficiencies/Productivity
A-17-2	Productivity Metrics

A-17-2 Attachment 1	Measuring Productivity at Hydro One
A-17-2 Attachment 2	OEB Expert Evidence Requirements
C1-5-1	Corporate Staffing
C1-5-2	Compensation, Wages, Benefits
C1-5-2 Attachment 1	Mercer Compensation Cost Benchmarking Study
C1-5-2 Attachment 2	Payroll Table 2009 to 2012
C1-5-3	Pension Costs
C2-3-1	Comparison of Wages and Salaries
I-7-1.01 Staff 39	OEB Interrogatory #39
I-7-1.02 Staff 40	OEB Interrogatory #40
I-7-1.03 Staff 41	OEB Interrogatory #41
I-7-1.04 Staff 42	OEB Interrogatory #42
I-7-1.05 Staff 43	OEB Interrogatory #43
I-7-1.06 Staff 44	OEB Interrogatory #44
I-7-1.07 Staff 45	OEB Interrogatory #45
I-7-1.08 Staff 46	OEB Interrogatory #46
I-7-2.01 LPMA 13	LPMA Interrogatory #13
I-7-2.02 LPMA 14	LPMA Interrogatory #14
I-7-3.01 EP 27	Energy Probe Interrogatory #27
I-7-3.02 EP 28	Energy Probe Interrogatory #28
I-7-3.03 EP 29	Energy Probe Interrogatory #29
I-7-3.04 EP 30	Energy Probe Interrogatory #30
I-7-3.05 EP 31	Energy Probe Interrogatory #31
I-7-3.06 EP 32	Energy Probe Interrogatory #32
I-7-3.07 EP 33	Energy Probe Interrogatory #33
I-7-3.09 EP 35	Energy Probe Interrogatory #35
I-7-3.10 EP 36	Energy Probe Interrogatory #36
I-7-3.11 EP 37	Energy Probe Interrogatory #37
I-7-3.13 EP 39	Energy Probe Interrogatory #39
I-7-3.14 EP 40	Energy Probe Interrogatory #40
I-7-3.15 EP 41	Energy Probe Interrogatory #41
I-7-3.16 EP 42	Energy Probe Interrogatory #42
I-7-3.17 EP 43	Energy Probe Interrogatory #43
I-7-3.18 EP 44	Energy Probe Interrogatory #44
I-7-3.19 EP 45	Energy Probe Interrogatory #45
I-7-3.20 EP 46	Energy Probe Interrogatory #46
I-7-3.21 EP 47	Energy Probe Interrogatory #47
I-7-3.22 EP 48	Energy Probe Interrogatory #48
I-7-3.23 EP 49	Energy Probe Interrogatory #49
I-7-5.01 VECC 32	VECC Interrogatory #32
I-7-8.01 PWU 17	PWU Interrogatory #17

I-7-9.01 SEC 20	SEC Interrogatory #20
I-7-9.02 SEC 21	SEC Interrogatory #21
I-7-9.03 SEC 22	SEC Interrogatory #22
I-7-10.01 CCC 23	CCC Interrogatory #23
I-7-10.02 CCC 24	CCC Interrogatory #24
I-7-10.03 CCC 25	CCC Interrogatory #25
I-7-10.04 CCC 26	CCC Interrogatory #26
I-7-13.01 AMPCO 4	AMPCO Interrogatory #4
I-7-13.02 AMPCO 5	AMPCO Interrogatory #5
I-7-13.03 AMPCO 6	AMPCO Interrogatory #6
I-7-13.04 AMPCO 7	AMPCO Interrogatory #7
JT1.1 TCR Staff 12	OEB Technical Conference Response #12
JT1.1 TCR Staff 13	OEB Technical Conference Response #13
JT1.1 TCR Staff 14	OEB Technical Conference Response #14
JT1.1 TCR Staff 15	OEB Technical Conference Response #15
JT1.1 TCR Staff 16	OEB Technical Conference Response #16
JT1.2 TCR EP3	Energy Probe Technical Conference Response #3
KT1.9	Undertaking Response #9
KT1.10	Undertaking Response #10
KT1.11	Undertaking Response #11
KT1.16	Undertaking Response #16
KT1.27	Undertaking Response #27
KT1.28	Undertaking Response #28
KT1.31	Undertaking Response #31
KT1.32	Undertaking Response #32
KT1.33	Undertaking Response #33
KT1.34	Undertaking Response #34

Supporting Parties: EP, SEC, VECC, LPMA, BOMA, CCC, CME, AMPCO

Parties taking no position: PWU, Goldcorp, APPrO

8. Are the methodologies used to allocate Shared Services and Other O & M costs to the transmission business and to determine the transmission overhead capitalization rate for 2013/14 appropriate?

Settled. For the purposes of reaching a settlement, the parties agree that Hydro One has used the Corporate Cost Allocation Methodology previously accepted by the Board in prior Hydro One Network Transmission and Distribution Rate Applications. Similarly, Hydro One has followed the overhead capitalization rate methodology previously accepted by the Board. Both of these have been updated for the current filing. The parties thus agree that the methodologies used to allocate Shared Services and Other O&M costs to the transmission overhead capitalization rate for 2013 and 2014 are appropriate.

Evidence: The evidence in relation to this issue includes the following:

C1-7-1	Common Corporate Costs, Cost Allocation Methodology
C1-7-1 Attachment 1	Review of Shared Services Cost Allocation (Transmisison) – 2012
C1-7-2	Overhead Capitalization Rate
C1-7-2 Attachment 1	Review of Overhead Capitalization Rates (Transmission) – 2013-2014
C1-7-2 Attachment 2	Review of Overhead Capitalization Policy
I-8-3.01 EP 50	Energy Probe Interrogatory #50
I-8-3.02 EP 51	Energy Probe Interrogatory #51
I-8-9.01 SEC 23	SEC Interrogatory #23
I-8-10.01 CCC 27	CCC Interrogatory #27
JT1.2 TCR EP5	Energy Probe Technical Conference Response #5
JT1.2 TCR EP6	Energy Probe Technical Conference Response #6

Supporting Parties: PWU, AMPCO, SEC, CCC, CME

Parties taking no position: EP, VECC, LPMA, BOMA, Goldcorp, APPrO

9. Are the amounts proposed to be included in the 2013 and 2014 revenue requirements for income and other taxes appropriate?

Settled. For the purposes of reaching a settlement, the parties agree that the amounts proposed to be included in the 2013 and 2014 revenue requirement for income and other taxes are appropriate, subject to an increase in the Apprenticeship Tax Credit by $1.3M in 2013 and $1.0M in 2014 (resulting in corresponding decreases in tax expenses included in rates).

Evidence: The evidence in relation to this issue includes the following:

C1-9-1	Payments in Lieu of Corporate Income Taxes
C2-5-1	Calculation of Utility Income Taxes
C2-5-1 Attachment 1	Calculation of Utility Income Taxes Test Years (2013, 2014)
C2-5-1 Attachment 2	Calculation of Capital Cost Allowance Test Years (2013, 2014)
C2-5-1 Attachment 3	Calculation of Utility Income Taxes Historic Years (2009, 2010)

C2-5-1 Attachment 4	Calculation of Capital Cost Allowance Historic Years (2009, 2010) and Forecast Years (2011, 2012)
C2-5-1 Attachment 5	Calculation of Apprenticeship and Education Tax Credit Test Years (2013, 2014)
C2-5-1 Attachment 6	Calculation of Apprenticeship and Education Tax Credit Historic Years (2009, 2010)
C2-5-2	2010 Hydro One Networks Income Tax Return
C2-5-2 Attachment 1	Federal and Ontario Income Tax Return
C2-5-2 Attachment 2	Calculation of Utility Income Taxes (Transmission and Distribution)
C2-5-2 Attachment 3	Calculation of Capital Cost Allowance (Transmission and Distribution)
C2-5-3	2011 Hydro One Networks Income Tax Return
C2-5-3 Attachment 1	Federal and Ontario Income Tax Return
C2-5-3 Attachment 2	Calculation of Utility Income Taxes (Transmission and Distribution)
C2-5-3 Attachment 3	Calculation of Capital Cost Allowance (Transmission and Distribution)
I-9-1.01 Staff 47	OEB Interrogatory #47
I-9-1.02 Staff 48	OEB Interrogatory #48
I-9-1.03 Staff 49	OEB Interrogatory #49
I-9-2.01 LPMA 15	LPMA Interrogatory #15
I-9-2.02 LPMA 16	LPMA Interrogatory #16
I-9-2.03 LPMA 17	LPMA Interrogatory #17
I-9-2.04 LPMA 18	LPMA Interrogatory #18
I-9-2.05 LPMA 19	LPMA Interrogatory #19
I-9-2.06 LPMA 20	LPMA Interrogatory #20
I-9-2.07 LPMA 21	LPMA Interrogatory #21
JT1.1 TCR Staff 17	OEB Technical Conference Response #17

Supporting Parties: EP, SEC, VECC, LPMA, BOMA, CCC, CME, PWU, AMPCO

Parties taking no position: Goldcorp, APPrO

10. Is Hydro One Networks' proposed depreciation expense for 2013 and 2014 appropriate?

Settled. For the purposes of reaching a settlement, the parties agree that the proposed depreciation expense for 2013 and 2014 which reflects the 2011

Depreciation Rate Review filed at Exhibit C1, Tab 8, Schedule 1, Attachment 1 is appropriate.

Evidence: The evidence in relation to this issue includes the following:

C1-8-1	Depreciation and Amortization Expenses
C1-8-1 Attachment 1	2011 Depreciation Rate Review
C2-4-1	Depreciation and Amortization Expenses
I-10-2.01 LPMA 22	LPMA Interrogatory #22

Supporting Parties: EP, LPMA, SEC, VECC, BOMA, CCC, CME, PWU, AMPCO

Parties taking no position: Goldcorp, APPrO

CAPITAL EXPENDITURES AND RATE BASE

11. Are the amounts proposed for rate base in 2013 and 2014 appropriate?

Partially Settled. The Applicant has proposed a rate base of $9,413.5M and $10,050.9M in the test years.

For the purposes of reaching a settlement, Hydro One has agreed to reduce its planned capital expenditures in 2013 as outlined below in Issue 12. This will result in reduced in-service additions in 2013, which has an associated reduction in rate base for both 2013 and 2014.

Taking into account those reductions, the parties other than Goldcorp agree that a rate base of $9,353.4M in 2013 and a rate base of $9,933.8M in 2014 are appropriate. This represents a reduction in rate base of $60.1M in 2013 and $117.1M in 2014 compared to that initially proposed, after reflecting depreciation.

Detailed calculations are provided in the table below.

Capital Expenditures ($M)	***2012***	***2013***	***2014***
Filed Evidence	850.0	1,102.4	1,121.5
Settlement Agreement	850.0	982.4	1,121.5
Change Proposed	-	- 120.0	-
In-Service ($M)			

Filed Evidence	1,294.7	904.1	1,023.0
Settlement Agreement	1,295.0	784.1	1,023.0
Change Proposed	-	- 120.0	-
Gross In-Service Impact on Rate Base ($M)			
Filed Evidence	8,628.5	9,413.5	10,050.9
Settlement Agreement	8,628.5	9,353.5	9,930.9
Change Proposed	-	- 60.0	- 120.0
Net Rate Base after Accumulated Depreciation ($M)			
Filed Evidence	8,628.5	9,413.5	10,050.9
Settlement Agreement	8,628.5	9,353.4	9,933.8
Change Proposed		- 60.1	- 117.1

The only aspect of this issue which remains unsettled is the net book value of Red Lake TS. Goldcorp is the only intervenor with concerns in this regard. Hydro One and Goldcorp have written separately to the Board regarding this issue.

Evidence: The evidence in relation to this issue includes the following:

D1-1-1	Rate Base
D1-1-2	In-Service Capital Additions
D1-2-1	Allowance for Funds Used During Construction
D1-5-1	Materials and Supplies Inventory
D2-1-1	Statement of Utility Rate Base
D2-3-1	Continuity of Property, Plant and Equipment
D2-3-2	Continuity of Accumulated Depreciation
D2-3-3	Continuity of Property, Plant and Equipment - Construction Work In Progress
I-11-1.01 Staff 50	OEB Interrogatory #50
I-11-1.02 Staff 51	OEB Interrogatory #51
I-11-1.03 Staff 52	OEB Interrogatory #52
I-11-1.04 Staff 53	OEB Interrogatory #53
I-11-2.01 LPMA 23	LPMA Interrogatory #23
I-11-2.02 LPMA 24	LPMA Interrogatory #24
I-11-2.03 LPMA 25	LPMA Interrogatory #25
I-11-4.01 PP 1	Pollution Probe Interrogatory #1
I-11-4.02 PP 2	Pollution Probe Interrogatory #2
I-11-4.03 PP 3	Pollution Probe Interrogatory #3
I-11-4.04 PP 4	Pollution Probe Interrogatory #4
I-11-4.05 PP 5	Pollution Probe Interrogatory #5
I-11-4.06 PP 6	Pollution Probe Interrogatory #6
I-11-4.07 PP7	Pollution Probe Interrogatory #7
I-11-4.08 PP 8	Pollution Probe Interrogatory #8

I-11-4.09 PP 9	Pollution Probe Interrogatory #9
I-11-4.10 PP 10	Pollution Probe Interrogatory #10
I-11-4.11 PP 11	Pollution Probe Interrogatory #11
I-11-4.12 PP 12	Pollution Probe Interrogatory #12
I-11-4.13 PP 13	Pollution Probe Interrogatory #13
I-11-4.14 PP 14	Pollution Probe Interrogatory #14
I-11-4.15 PP 15	Pollution Probe Interrogatory #15
I-11-4.16 PP 16	Pollution Probe Interrogatory #16
I-11-4.17 PP 17	Pollution Probe Interrogatory #17
I-11-4.18 PP 18	Pollution Probe Interrogatory #18
I-11-4.19 PP 19	Pollution Probe Interrogatory #19
I-11-4.20 PP 20	Pollution Probe Interrogatory #20
I-11-4.21 PP 21	Pollution Probe Interrogatory #21
I-11-4.22 PP 22	Pollution Probe Interrogatory #22
I-11-4.23 PP 23	Pollution Probe Interrogatory #23
I-11-4.24 PP 24	Pollution Probe Interrogatory #24
I-11-4.25 PP 25	Pollution Probe Interrogatory #25
I-11-4.26 PP 26	Pollution Probe Interrogatory #26
I-11-4.27 PP 27	Pollution Probe Interrogatory #27
I-11-4.28 PP 28	Pollution Probe Interrogatory #28
I-11-4.29 PP 29	Pollution Probe Interrogatory #29
I-11-5.01 VECC 33	VECC Interrogatory #33
I-11-7.01 Gold 1	Goldcorp Interrogatory #1
I-11-7.02 Gold 2	Goldcorp Interrogatory #2
I-11-7.03 Gold 3	Goldcorp Interrogatory #3
I-11-7.04 Gold 4	Goldcorp Interrogatory #4
I-11-7.05 Gold 5	Goldcorp Interrogatory #5
I-11-7.06 Gold 6	Goldcorp Interrogatory #6
I-11-9.01 SEC 24	SEC Interrogatory #24
I-11-12.01 THESL 2	THESL Interrogatory #2
I-11-12.02 THESL 3	THESL Interrogatory #3
I-11-12.03 THESL 4	THESL Interrogatory #4
I-11-12.04 THESL 5	THESL Interrogatory #5
I-11-13.01 AMPCO 8	AMPCO Interrogatory #8
I-11-13.02 AMPCO 9	AMPCO Interrogatory #9
JT1.1 TCR PP1	Pollution Probe Technical Conference Response #1
JT1.1 TCR PP2	Pollution Probe Technical Conference Response #2
JT1.1 TCR PP3	Pollution Probe Technical Conference Response #3
JT1.1 TCR PP4	Pollution Probe Technical Conference Response #4
KT1.5	Undertaking Response #5

Supporting Parties: EP, SEC, VECC, LPMA, BOMA, CCC, CME, AMPCO

Parties taking no position: PWU, APPrO

12. Are the proposed 2013 and 2014 Sustaining and Development and Operations capital expenditures appropriate, including consideration of factors such as system reliability and asset condition?

Settled.

For the purposes of reaching a settlement, the parties agreed to reduce 2013 capital expenditures and in service additions by $120.0 M from $1,102.4M to $982.4M. The reductions will be recognized through the re-prioritization of investments based on Hydro One's Investment Planning and Prioritization process to ensure the impact to risks and business values are minimized while reducing the overall rate impacts on customers. For the purposes of reaching a settlement, the parties agree that capital expenditures , for 2013 and 2014 are appropriate, with the agreed upon reduction in 2013.

The table below summarizes the proposed changes:

Capital Expenditures ($M)	***2012***	***2013***	***2014***
Filed Evidence	850	1102	1122
Settlement Agreement	850	982	1122
Change Proposed		-120	0

Evidence: The evidence in relation to this issue includes the following:

D1-3-1	Summary of Capital Expenditures
D1-3-2	Sustaining Capital
D1-3-3	Development Capital
D1-3-3 Appendix A	Summary of Development Capital Projects in Excess of $3 Million
D1-3-3 Appendix B	OPA Supporting Material for Oshawa TS
D1-3-3 Appendix C	OPA Document on Southwestern Ontario Reactive Compensation Milton SVC dated March 2012
D1-3-3 Appendix D	Letter from OPA dated June 30, 2011
D1-3-3 Appendix E	Letter from OPA dated March 8, 2012
D1-3-3 Appendix F	Letter from OPA dated August 7, 2012
D1-3-4	Operations Capital
D2-2-1	Comparison of Net Capital Expenditures by Major Category – Historic, Bridge Year and Test Year
D2-2-2	List of Capital Expenditure Programs or Projects Requiring in Excess of $3 Million in Test Year 2013 or 2014

D2-2-3	Investment Summary for Programs/Projects in Excess of $3 Million
I-12-1.01 Staff 54	OEB Interrogatory #54
I-12-1.02 Staff 55	OEB Interrogatory #55
I-12-1.03 Staff 56	OEB Interrogatory #56
I-12-1.04 Staff 57	OEB Interrogatory #57
I-12-1.05 Staff 58	OEB Interrogatory #58
I-12-1.06 Staff 59	OEB Interrogatory #59
I-12-1.07 Staff 60	OEB Interrogatory #60
I-12-1.08 Staff 61	OEB Interrogatory #61
I-12-1.09 Staff 62	OEB Interrogatory #62
I-12-1.10 Staff 63	OEB Interrogatory #63
I-12-1.11 Staff 64	OEB Interrogatory #64
I-12-1.12 Staff 65	OEB Interrogatory #65
I-12-1.13 Staff 66	OEB Interrogatory #66
I-12-1.14 Staff 67	OEB Interrogatory #67
I-12-1.15 Staff 68	OEB Interrogatory #68
I-12-1.16 Staff 69	OEB Interrogatory #69
I-12-1.17 Staff 70	OEB Interrogatory #70
I-12-1.18 Staff 71	OEB Interrogatory #71
I-12-1.19 Staff 72	OEB Interrogatory #72
I-12-3.01 EP 52	Energy Probe Interrogatory #52
I-12-3.02 EP 53	Energy Probe Interrogatory #53
I-12-3.03 EP 54	Energy Probe Interrogatory #54
I-12-3.04 EP 55	Energy Probe Interrogatory #55
I-12-9.01 SEC 25	SEC Interrogatory #25
I-12-9.02 SEC 26	SEC Interrogatory #26
I-12-9.03 SEC 27	SEC Interrogatory #27
I-12-9.04 SEC 28	SEC Interrogatory #28
I-12-9.05 SEC 29	SEC Interrogatory #29
I-12-9.06 SEC 30	SEC Interrogatory #30
I-12-9.07 SEC 31	SEC Interrogatory #31
I-12-9.08 SEC 32	SEC Interrogatory #32
I-12-9.09 SEC 33	SEC Interrogatory #33
I-12-9.10 SEC 34	SEC Interrogatory #34
I-12-10.01 CCC 28	CCC Interrogatory #28
I-12-10.02 CCC 29	CCC Interrogatory #29
I-12-10.03 CCC 30	CCC Interrogatory #30
I-12-10.04 CCC 31	CCC Interrogatory #31
I-12-10.05 CCC 32	CCC Interrogatory #32
I-12-12.01 THESL 6	THESL Interrogatory #6

I-12-12.02 THESL 7	THESL Interrogatory #7
I-12-12.03 THESL 8	THESL Interrogatory #8
I-12-12.04 THESL 9	THESL Interrogatory #9
I-12-12.05 THESL 10	THESL Interrogatory #10
I-12-13.01 AMPCO 10	AMPCO Interrogatory #10
JT1.1 TCR Staff 23	OEB Technical Conference Response #23
JT1.2 TCR EP8	Energy Probe Technical Conference Response #8
KT1.29	Undertaking Response #29
KT1.30	Undertaking Response #30

Supporting Parties: EP, SEC, VECC, LPMA, BOMA, CCC, CME, AMPCO

Parties taking no position: PWU, Goldcorp, APPrO

13. Are the proposed 2013 and 2014 levels of Shared Services and Other Capital expenditures appropriate?

    Settled. Please see rationale for issue 12 above. For the purposes of reaching a settlement, the parties agree that the proposed 2013 and 2014 levels of Shared Services and Other Capital expenditures are appropriate.

    Evidence: The evidence in relation to this issue includes the following:

D1-4-1	Summary of Shared Services Capital
D1-4-2	Shared Services Capital – Information Technology
D1-4-3	Shared Services Capital – Cornerstone
D1-4-4	Shared Services Capital – Facilities & Real Estate
D1-4-5	Shared Services Capital – Transport, Work and Service Equipment
D2-2-1	Comparison of Net Capital Expenditures by Major Category – Historic, Bridge Year and Test Year
D2-2-2	List of Capital Expenditure Programs or Projects Requiring in Excess of $3 Million in Test Year 2013 or 2014
D2-2-3	Investment Summary for Programs/Projects in Excess of $3 Million
I-13-9.01 SEC 35	SEC Interrogatory #35
I-13-10.01 CCC 33	CCC Interrogatory #33
I-13-10.02 CCC 34	CCC Interrogatory #34
I-13-10.03 CCC 35	CCC Interrogatory #35

Supporting Parties: AMPCO, SEC, CCC, CME

Parties taking no position: EP, VECC, LPMA, BOMA, PWU, Goldcorp, APPrO

14. Are the methodologies used to allocate shared services and other capital expenditures to the transmission business appropriate?

Settled. Hydro One has used the Corporate Cost Allocation Methodology previously accepted by the Board in prior Hydro One Network Transmission and Distribution Rate Applications. For the purposes of reaching a settlement, the parties accept that the methodologies used to allocate Shared Services and other capital costs to the transmission business are appropriate.

Evidence: The evidence in relation to this issue includes the following:

C1-7-3	Common Asset Allocation
C1-7-3 Attachment 1	Review of Shared Assets Allocation (Transmission) - 2012

Supporting Parties: SEC, VECC, BOMA, CCC, CME, PWU, AMPCO

Parties taking no position. EP, LPMA, Goldcorp, APPrO

15. Are the inputs used to determine the working capital component of the rate base and the methodology used appropriate?

Settled. For the purposes of reaching a settlement the parties agree that the inputs and methodology used by the Applicant to determine the working capital component of the rate base are appropriate.

Evidence: The evidence in relation to this issue includes the following:

D1-1-3	Working Capital
D1-1-3 Attachment 1	A Determination of the Working Capital Requirements of Hydro One Networks' Transmission Business
D2-4-1	Statement of Working Capital
I-15-2.01 LPMA 26	LPMA Interrogatory #26
I-15-2.02 LPMA 27	LPMA Interrogatory #27
I-15-3.01 EP 56	Energy Probe Interrogatory #56

Supporting Parties: EP, VECC, LPMA, SEC, BOMA, CCC, CME, PWU, AMPCO

Parties taking no position: Goldcorp, APPrO

16. Does Hydro One's Asset Condition Assessment information and Investment Planning Process adequately address the condition of the transmission system assets and support the O&MA and Capital expenditures for 2013/14.

Settled. For the purposes of reaching a settlement**,** the parties accept that Hydro One's Asset Condition Assessment information and Investment Planning Process adequately address the condition of the transmission system assets in support of the OM&A and Capital expenditures for 2013 and 2014.

Evidence: The evidence in relation to this issue includes the following:

A-13-1	Planning Process
A-13-1 Appendix A	2012 Business Plan Assumptions
A-13-2	Transmission 10 Year Outlook
A-15-3	Investment Plan Development
A-15-4	Investment Prioritization Process
A-15-5	Project and Program Approval & Control
C1-2-1	Sustaining Investment Structure
C1-2-2	Transmission Assets and Sustaining Investment Overview
C1-2-2 Appendix A	Hydro One Transmission Asset Descriptions
I-16-1.01 Staff 73	OEB Interrogatory #73
I-16-1.02 Staff 74	OEB Interrogatory #74
I-16-1.03 Staff 75	OEB Interrogatory #75
I-16-1.04 Staff 76	OEB Interrogatory #76

Supporting Parties: SEC, VECC, LPMA, EP, BOMA, CCC, CME, PWU, AMPCO

Parties taking no position: Goldcorp, APPrO

COST OF CAPITAL/CAPITAL STRUCTURE

17. Is the proposed timing and methodology for determining the return on equity and short-term debt prior to the effective date of rates appropriate?

Settled. For the purposes of reaching a settlement the parties agree that the proposed timing and methodology as outlined in Exhibit B1, Tab 1, Schedule 1 is appropriate for determining the return on equity and short-term debt prior to the effective date of the rates as reflected in the Board approved rate order for the test years.

The table below summarizes the revenue requirement impact of the proposed changes to the 2013 and 2014 rate base based on the applied for Cost of Capital parameters.

Cost of Capital ($M)*	***2013***	***2014***
Filed Evidence	618.1	668.1
Settlement Agreement*	614.2	660.4
Change Proposed	(3.9)	(7.7)

*Includes return on equity and cost of short and long term debt.

Evidence: The evidence in relation to this issue includes the following:

B1-1-1	Cost of Capital
B2-1-1	Debt and Equity Summary
I-17-2.01 LPMA 28	LPMA Interrogatory #28
I-17-3.01 EP 57	Energy Probe Interrogatory #57
I-17-10.01 CCC 36	CCC Interrogatory #36
I-17-13.01 AMPCO 11	AMPCO Interrogatory #11

Supporting Parties: EP, SEC, VECC, LPMA, BOMA, CCC, CME, PWU, AMPCO

Parties taking no position: Goldcorp, APPrO

18. Is the forecast of long term debt for 2012-2014 appropriate?

Settled. For the purposes of reaching a settlement the parties agree the forecast of long term debt rates following the methodology outlined in Exhibit B1, Tab 2, Schedule 1 is appropriate. Please see the table above under Issue 17.

Evidence: The evidence in relation to this issue includes the following:

B1-2-1	Cost of Third Party Long-Term Debt
B2-1-2	Cost of Long-Term Debt Capital
I-18-2.01 LPMA 29	LPMA Interrogatory #29
I-18-2.02 LPMA 30	LPMA Interrogatory #30
I-18-2.03 LPMA 31	LPMA Interrogatory #31
I-18-3.01 EP 58	Energy Probe Interrogatory #58
I-18-3.02 EP 59	Energy Probe Interrogatory #59
I-18-3.03 EP 60	Energy Probe Interrogatory #60
I-18-9.01 SEC 36	SEC Interrogatory #36
I-18-9.02 SEC 37	SEC Interrogatory #37

Supporting Parties: EP, SEC, VECC, LPMA, BOMA, CCC, CME, PWU, AMPCO

Parties taking no position: Goldcorp, APPrO

DEFERRAL/VARIANCE ACCOUNTS

19. Are the proposed amounts, disposition and continuance of Hydro One's existing Deferral and Variance accounts appropriate?

Settled. For the purposes of reaching a settlement, the parties accept Hydro One's account balances.

As noted in Issue 2 above, the parties agree that the amounts refunded to rate payers in 2013 associated with the ($30.3) million regulatory asset balance will be used as a balancing item to ensure a 0.0% increase for 2013. Any remaining balance will be refunded to customers in 2014. The precise amount to be refunded in each year will be reflected in the final rate order once the cost of capital has been established.

In addition, as noted above, the parties agreed that should the Board approve a change in the Export Transmission Services rate, the full impact of the approved rate will be tracked in the Board approved Excess Export Services Revenue Account for disposition in a future rate application.

As of December 31, 2012, both the Impact for Changes in USGAAP Account and the USGAAP Incremental Transition Costs had zero balances. For the purposes of reaching a settlement, Hydro One agreed to discontinue those two accounts. This is reflected in Appendix A.

Evidence: The evidence in relation to this issue includes the following:

F1-1-1	Regulatory Accounts
F1-1-3	Planned Disposition of Regulatory Accounts
F2-1-1	Regulatory Accounts for Approval
F2-1-2	Schedule of Annual Recoveries
F2-1-3	Continuity Schedules – Regulatory Accounts
I-19-1.01 Staff 77	OEB Interrogatory #77
I-19-1.02 Staff 78	OEB Interrogatory #78
I-19-1.03 Staff 79	OEB Interrogatory #79
I-19-1.04 Staff 80	OEB Interrogatory #80
I-19-3.01 EP 61	Energy Probe Interrogatory #61
I-19-9.01 SEC 38	SEC Interrogatory #38
I-19-9.02 SEC 39	SEC Interrogatory #39
I-19-10.01 CCC 37	CCC Interrogatory #37
I-19-10.02 CCC 38	CCC Interrogatory #38
I-19-10.03 CCC 39	CCC Interrogatory #39

JT1.1 TCR Staff 25	OEB Technical Conference Response #25
JT1.2 TCR EP9	Energy Probe Technical Conference Response #9
KT1.35	Undertaking Response #35

Supporting Parties: SEC, VECC, BOMA, CCC, CME, PWU, AMPCO

Parties taking no position: EP, LPMA, Goldcorp, APPrO

20. Are the proposed new Deferral and Variance Accounts appropriate?

Settled.

For the purposes of reaching a settlement and as previously described Hydro One has agreed to create two new variance accounts to track variances in

a) other external revenues and

b) the differences between the forecast and actual CDM savings related to the OPA funded LDC delivered programs and the actual Demand Response results against forecast. The CDM variance account is more fully described above in the context of Issue 3.

For the Other External Revenues Variance Account, Hydro One will establish a new variance account to record the differences between Other External Revenues embedded in rates and Actual Revenues.

These new proposed accounts have also been reflected in Appendix A.

Evidence: The evidence in relation to this issue includes the following:

F1-1-2	Regulatory Accounts Requested
I-20-1.01 Staff 81	OEB Interrogatory #81
I-20-10.01 CCC 40	CCC Interrogatory #40
I-20-10.02 CCC 41	CCC Interrogatory #41
JT1.1 TCR Staff 26	OEB Technical Conference Response #26

Supporting Parties: EP, SEC, VECC, LPMA, BOMA, CCC, CME, PWU, AMPCO

Parties taking no position: Goldcorp, APPrO

COST ALLOCATION

21. Is the cost allocation proposed by Hydro One appropriate?

Settled. Hydro One is proposing to continue to use the cost allocation methodology previously approved by the Board. For the purposes of reaching a settlement, the parties agree that the cost allocation proposed by Hydro One is appropriate.

Attached at Appendix C is an updated Draft Summary Uniform Transmission Rates and Revenue Disbursements Factors for 2013 and 2014.

Evidence: The evidence in relation to this issue includes the following:

G1-1-1	Cost Allocation and Charge Determinants
G1-2-1	Description of Cost Allocation Methodology
G1-3-1	Network and Line Connection Pools
G1-4-1	Transformation Connection Pool
G1-5-1	Wholesale Meter Pool
G1-6-1	Low Voltage Switchgear Compensation
G2-1-1	List of Transmission Lines by Functional Category
G2-1-2	List of Transmission Stations by Functional Category
G2-2-1	Allocation Factors for Dual Function Lines
G2-3-1	Allocation Factors for Generator Line Connections
G2-3-2	Allocation Factors For Generator Station Connections
G2-4-1	Asset Value by Functional Category
G2-4-2	Depreciation by Functional Category
G2-4-3	Return on Capital and Income Taxes by Functional Category
G2-4-4	OM&A Costs by Functional Category
G2-5-1	Detailed Revenue Requirement by Rate Pool
H1-1-1	Overview of Uniform Transmission Rates
H1-2-1	Transmission Customers Load Forecast
H1-3-1	Charge Determinants
H1-4-1	Rates for Wholesale Meter Service
H2-1-1	Current Ontario Transmission Rate Schedules
H2-1-1 Attachment 1	Ontario Transmission Rates Schedules EB-2011-0268
H2-1-1 Attachment 2	Uniform Transmission Rates and Revenue Disbursement Allocators
H2-2-1	Current Wholesale Meter Service and Exit Fee Schedule
H2-2-2	Proposed Wholesale Meter Service and Exit Fee Schedule
I-21-5.01 VECC 34	VECC Interrogatory #34
I-21-5.02 VECC 35	VECC Interrogatory #35
I-21-5.03 VECC 36	VECC Interrogatory #36
I-21-5.04 VECC 37	VECC Interrogatory #37
I-21-5.05 VECC 38	VECC Interrogatory #38
I-21-5.06 VECC 39	VECC Interrogatory #39

I-21-5.07 VECC 40	VECC Interrogatory #40

Supporting Parties: EP, SEC, VECC, LPMA, BOMA, CCC, CME, PWU, AMPCO

Parties taking no position: Goldcorp, APPrO

GREEN ENERGY PLAN

22. Are the OM&A and capital amounts in the Green Energy Plan (GEP) appropriate and based on appropriate planning criteria?

Settled. For the purposes of reaching a settlement, the parties accept the filed GEP as appropriate for 2013 and 2014.

Hydro One clarified that the approvals for OM&A and capital sought in the GEP are the same projects included in the overall proposals for OM&A and capital. Given agreement regarding OM&A and capital, there is agreement for the GEP. Hydro One confirmed that it is not seeking Board approval of elements of the plan that go beyond the test years.

The 2013 and 2014 elements of Hydro One's GEP are covered by the settlement of Issues 2 to 18 inclusive. Intervenors have no questions in this proceeding on the elements of Hydro One's GEP that lie outside the ambit of the 2013 and 2014 test years.

Evidence: The evidence in relation to this issue includes the following:

A-14-1	Transmission Green Energy Plan
A-14-1 Appendix A	Letter from Ministry of Energy and Infrastructure – dated September 21, 2009
A-14-1 Appendix B	Letters from Ministry of Energy and Infrastructure – dated May 5, 2010 and May 7, 2010
A-14-1 Appendix C	Letter from Ontario Power Authority – dated April 7, 2011
A-14-1 Appendix D	Letter from Hydro One – dated December 29, 2009
I-22-1.01 Staff 82	OEB Interrogatory #82
I-22-1.02 Staff 83	OEB Interrogatory #83
I-22-3.01 EP 62	Energy Probe Interrogatory #62
I-22-3.02 EP 63	Energy Probe Interrogatory #63
I-22-3.03 EP 64	Energy Probe Interrogatory #64
I-22-3.04 EP 65	Energy Probe Interrogatory #65
I-22-3.05 EP 66	Energy Probe Interrogatory #66

I-22-9.01 SEC 40	SEC Interrogatory #40
I-22-13.01 AMPCO 12	AMPCO Interrogatory #12
I-22-13.02 AMPCO 13	AMPCO Interrogatory #13
I-22-13.03 AMPCO 14	AMPCO Interrogatory #14
I-22-13.04 AMPCO 15	AMPCO Interrogatory #15
I-22-13.05 AMPCO 16	AMPCO Interrogatory #16
I-22-13.06 AMPCO 17	AMPCO Interrogatory #17
I-22-13.07 AMPCO 18	AMPCO Interrogatory #18
I-22-13.08 AMPCO 19	AMPCO Interrogatory #19

Supporting Parties: SEC, VECC, BOMA, CCC, CME, PWU, AMPCO

Parties taking no position: EP, LPMA, Goldcorp, APPrO

EXPORT TRANSMISSION SERVICE RATES

23. What is the appropriate level for Export Transmission Rates in Ontario?

Not Settled. The parties agree that this issue should be determined in an oral hearing before the Board.

Evidence: The evidence in relation to this issue includes the following:

H1-5-1	Rates for Export Transmission Service
H1-5-2	IESO Export Transmission Service Study
H2-1-2	Proposed Uniform Transmission Rates
I-23-1.01 Staff 84	OEB Interrogatory #84
I-23-1.02 Staff 85	OEB Interrogatory #85
I-23-1.03 Staff 86	OEB Interrogatory #86
I-23-1.04 Staff 87	OEB Interrogatory #87
I-23-1.05 Staff 88	OEB Interrogatory #88
I-23-1.06 Staff 89	OEB Interrogatory #89
I-23-1.07 Staff 90	OEB Interrogatory #90
I-23-1.08 Staff 91	OEB Interrogatory #91
I-23-1.09 Staff 92	OEB Interrogatory #92
I-23-5.01 VECC 41	VECC Interrogatory #41
I-23-5.02 VECC 42	VECC Interrogatory #42
I-23-5.03 VECC 43	VECC Interrogatory #43
I-23-5.04 VECC 44	VECC Interrogatory #44
I-23-5.05 VECC 45	VECC Interrogatory #45
I-23-5.06 VECC 46	VECC Interrogatory #46

I-23-5.07 VECC 47	VECC Interrogatory #47
I-23-5.08 VECC 48	VECC Interrogatory #48
I-23-5.09 VECC 49	VECC Interrogatory #49
I-23-5.10 VECC 50	VECC Interrogatory #50
I-23-5.11 VECC 51	VECC Interrogatory #51
I-23-5.12 VECC 52	VECC Interrogatory #52
I-23-5.13 VECC 53	VECC Interrogatory #53
I-23-5.14 VECC 54	VECC Interrogatory #54
I-23-6.01 HQ 1	HQ Interrogatory #1
I-23-6.02 HQ 2	HQ Interrogatory #2
I-23-6.03 HQ 3	HQ Interrogatory #3
I-23-6.04 HQ 4	HQ Interrogatory #4
I-23-6.05 HQ 5	HQ Interrogatory #5
I-23-6.06 HQ 6	HQ Interrogatory #6
I-23-6.07 HQ 7	HQ Interrogatory #7
I-23-6.08 HQ 8	HQ Interrogatory #8
I-23-6.09 HQ 9	HQ Interrogatory #9
I-23-6.10 HQ 10	HQ Interrogatory #10
I-23-6.11 HQ 11	HQ Interrogatory #11
I-23-6.12 HQ 12	HQ Interrogatory #12
I-23-6.13 HQ 13	HQ Interrogatory #13
I-23-6.14 HQ 14	HQ Interrogatory #14
I-23-6.15 HQ 15	HQ Interrogatory #15
I-23-6.16 HQ 16	HQ Interrogatory #16
I-23-8.01 PWU 18	PWU Interrogatory #18
I-23-9.01 SEC 41	SEC Interrogatory #41
I-23-9.02 SEC 42	SEC Interrogatory #42
I-23-9.03 SEC 43	SEC Interrogatory #43
I-23-10.01 CCC 42	CCC Interrogatory #42
I-23-11.01 APPrO 1	APPrO Interrogatory #1
I-23-11.02 APPrO 2	APPrO Interrogatory #2
I-23-11.03 APPrO 3	APPrO Interrogatory #3
I-23-11.04 APPrO 4	APPrO Interrogatory #4
I-23-11.05 APPrO 5	APPrO Interrogatory #5
I-23-11.06 APPrO 6	APPrO Interrogatory #6
I-23-11.07 APPrO 7	APPrO Interrogatory #7
I-23-11.08 APPrO 8	APPrO Interrogatory #8
I-23-11.09 APPrO 9	APPrO Interrogatory #9
I-23-11.10 APPrO 10	APPrO Interrogatory #10
I-23-11.11 APPrO 11	APPrO Interrogatory #11
I-23-11.12 APPrO 12	APPrO Interrogatory #12

KT1.1	Undertaking Response #1
KT1.2	Undertaking Response #2
KT1.3	Undertaking Response #3
KT1.4	Undertaking Response #4

Supporting Parties: NOT REQUIRED

Parties taking no position:

CONNECTION PROCEDURES

24. Are the proposed modifications to the Hydro One connection procedures appropriate?

Settled. Hydro One proposed some modifications to the connection procedures currently in use. The modifications were intended to reflect the overall timelines required for load connections and generation connections based on Hydro One's experience over the last few years. The current Board approved Transmission Connection Procedures for Hydro One included timeframes which are ambitious given the current realities of the electricity market.

AMPCO had some concerns with the proposed modifications. Hydro One clarified that the changes were intended to simply reflect the true timeframes required to connect a load or generation customer based on Hydro One's experience. In addition, the changes are more transparent as they reflect the overall timeframes for each phase of the connection process rather than simply timelines for Hydro One to complete those items for which it is responsible within each phase. The proposed changes provide customers better information. With that clarification, AMPCO's concerns were addressed.

In Exhibit I, Tab 24, Schedule 1.03 Staff 95, Hydro One proposed two further revisions to the proposed new connection procedures in parts f) and j) of the response. Hydro One agreed to include the proposed revised connection procedures as part of the draft rate order, which will include the two changes outlined in the interrogatory response.

Accordingly, the parties are in agreement that the proposed changes to the connection procedures for Hydro One are appropriate.

Evidence: The evidence in relation to this issue includes the following:

A-12-1	Key Governing Legislation, Standards and Codes
I-24-1.01 Staff 93	OEB Interrogatory #93
I-24-1.02 Staff 94	OEB Interrogatory #94
I-24-1.03 Staff 95	OEB Interrogatory #95

I-24-1.04 Staff 96	OEB Interrogatory #96
I-24-1.05 Staff 97	OEB Interrogatory #97
I-24-3.01 EP 67	Energy Probe Interrogatory #67
I-24-10.01 CCC 43	CCC Interrogatory #43
I-24-13.01 AMPCO 20	AMPCO Interrogatory #20
I-24-13.02 AMPCO 21	AMPCO Interrogatory #21
I-24-13.03 AMPCO 22	AMPCO Interrogatory #22
I-24-13.04 AMPCO 23	AMPCO Interrogatory #23
I-24-13.05 AMPCO 24	AMPCO Interrogatory #24

Supporting Parties: PWU, AMPCO

Parties taking no position: EP, SEC, VECC, LPMA, BOMA, CCC, CME, APPrO

ACCOUNTING STANDARDS

25. Have all impacts of the conversion of regulatory and financial accounting from CGAAP to USGAAP been identified and reflected in the appropriate manner in the Application, the revenue requirement for the Test Years and the proposed rates.

Settled. For the purposes of reaching a settlement the parties agree that all impacts of the conversion of regulatory and financial accounting from CGAAP to USGAAP have been identified and reflected in the appropriate manner in the Application, the revenue requirement for the test years and the proposed rates.

Evidence: The evidence in relation to this issue includes the following:

A-12-2	Summary of Hydro One Transmission Policies
I-25-1.01 Staff 98	OEB Interrogatory #98

Supporting Parties: SEC, VECC, LPMA, BOMA, CCC, CME, AMPCO, PWU

Parties taking no position: EP, APPrO

APPENDIX A

LIST OF APPROVALS SOUGHT

1. An Order pursuant to Section 78 of the *Ontario Energy Board Act* approving 2013 and 2014 Revenue Requirement and rates for the transmission of electricity to be implemented January 1, 2013 and January 1, 2014.

2. As a result of the Settlement Proposal, Hydro One Networks seeks approval of a revenue requirement of $1,446 million and $1,537 million for the test years 2013 and 2014, respectively. This results in an increase in Hydro One Transmission's Rates Revenue Requirement of 0% and 7.1%, respectively, reflecting an estimated increase on the average customer's total bill of 0.0% in 2013 and 0.6% in 2014. The estimate of the impact on a customer's total bill assumes commodity costs of 7.2¢/kWh and that transmission represents 7.9% of an average distribution connected customer's total bill.

3. Hydro One Networks seeks approval of regulatory assets totaling ($30.3) million as at December 31, 2012. Hydro One seeks approval to refund this balance over a two year period and to reduce the annual revenue requirement accordingly. Hydro One proposes to refund an amount that will ensure the overall rate increase in 2013 will be 0.0% and to refund any remaining balance to customers in 2014.

4. Hydro One Networks seeks approval to continue the following deferral accounts including, the Excess Export Service Revenue Account, the External Secondary Land Use Revenue Variance Account, the External Station Maintenance and E&CS Revenue Variance Account, the Tax Rate Changes Account, the Rights Payments Variance Account, the Pension Cost Differential Account, and the East-West Tie account.

5. For 2013 and 2014, Hydro One Transmission is requesting that the Board approve the establishment of four new deferral accounts, the External Revenue – Partnership Transmission Projects Account, the Long-Term Transmission Future Corridor

Acquisition and Development Account, the Other External Revenues Variance Account, the LDC CDM Demand Response Variance Account.

6. Hydro One Transmission is also requesting the discontinuance effective January 1, 2013 of the Deferred Export Service Credit Revenue Account, the Long Term Project Development Costs Account, the Impact for Changes in USGAAP Account and the USGAAP Incremental Transition Costs Account.

7. Hydro One Networks also requests the Board approve several proposed modifications to the current Transmission Connection Procedures, which were approved by the Board in EB-2006-0189 to reflect the current electricity market conditions with respect to the connection of renewable generation. The proposed changes relate to a number of sections in Hydro One Transmission's Connection Procedures including: 1) the Customer Connection Process, 2) Security Deposit Procedure, 3) Customer Impact Assessment Procedure, 4) Schedule of Charges and Fees, and 5) Connection Process Timelines. Hydro One will also incorporate further revisions to the proposed connection procedures as outlined in parts f) and j) of the interrogatory response to in Exhibit I, Tab 24, Schedule 1.03, Staff 95.

8. Approval of Hydro One's Green Energy Plan.

APPENDIX B

	Filing (Blue Page)			Reduce 2013 capex/in-service by $120M; decrease OM&A by $13M & $10M; increase 2014 ext. revenue by $4.8M; increase tax credit by $1.3M & $1M; adjust rider refund timing; updated LVSG			Variance	
Draft Rate Increases	ROE	ROE	ROE	ROE	ROE	ROE		
October 29, 2012	9.42%	9.16%	9.44%	9.42%	9.16%	9.44%		
	2012	2013	2014	2012	2013	2014		
Revenue requirement								
OM&A		453.3	459.7		440.3	449.7	(13.0)	(10.0)
Depreciation on fixed assets		346.7	374.7		345.0	371.5	(1.7)	(3.3)
Return on debt		268.3	283.8		266.5	280.5	(1.7)	(3.3)
Return on equity		344.9	379.5		342.7	375.1	(2.2)	(4.4)
Income tax		46.4	55.2		46.2	55.7	(0.2)	0.5
AFUDC		4.9	4.8		4.9	4.8	0.0	0.0
Revenue requirement	1,418.4	1,464.5	1,557.7	1,418.4	1,445.7	1,537.2	(18.7)	(20.5)
	5.4%	3.2%	6.4%	5.4%	1.9%	6.3%		
Less: Non-rate revenues	(28.7)	(31.6)	(31.8)	(28.7)	(31.6)	(36.6)	-	(4.8)
	1,389.7	1,432.8	1,525.9	1,389.7	1,414.1	1,500.6	(18.7)	(25.3)
	5.9%	3.1%	6.5%	5.9%	1.8%	6.1%		
Less: Export revenue credit	(16.0)	(31.0)	(30.1)	(16.0)	(31.0)	(30.1)		
	1,373.6	1,401.8	1,495.8	1,373.6	1,383.1	1,470.5		
	6.0%	2.1%	6.7%	6.0%	0.7%	6.3%		
Less: "Tx Riders"	-	(15.1)	(15.1)	-	(4.5)	(25.7)	10.6	(10.6)
	1,373.6	1,386.7	1,480.7	1,373.6	1,378.6	1,444.8	(8.1)	(35.9)
	6.6%	1.0%	6.8%	6.6%	0.4%	4.8%		
Add: LVSG	11.5	11.7	12.5	11.5	11.7	12.2	(0.1)	(0.3)
Rates Revenue Requirement	1,385.1	1,398.5	1,493.1	1,385.1	1,390.3	1,457.0	(8.2)	(36.2)
	6.6%	1.0%	6.8%	6.6%	0.4%	4.8%		
Estimated impact of load reduction	-1.2%	0.4%	**-2.3%**	-1.2%	0.4%	**-2.3%**		
Assumed Rate Impact	**7.8%**	**0.6%**	**9.1%**	**7.8%**	**0.0%**	**7.1%**		
Rate Base		9413.5	10050.9		9353.4	9933.8		

APPENDIX C

DRAFT

Summary Uniform Transmission Rates and Revenue Disbursement Factors
for Rates Effective January 1, 2013

Transmitter	Revenue Requirement ($)			
	Network	**Line Connection**	**Transformation Connection**	**Total**
FNEI (Note 3)	$3,897,095	$779,431	$1,650,564	$6,327,089
CNPI (Note 4)	$2,840,979	$568,204	$1,203,260	$4,612,443
GLPT (Note 5)	$21,710,466	$4,342,158	$9,195,184	$35,247,808
H1N (Note 1)	$855,746,155	$171,151,779	$362,440,102	$1,389,338,036
All Transmitters	$884,194,694	$176,841,572	$374,489,109	$1,435,525,376

Transmitter	Total Annual Charge Determinants (MW)			
	Network	**Line Connection**	**Transformation Connection**	
FNEI (Note 3)	187.1	213.5	76.2	
CNPI (Note 4)	583.4	668.6	668.6	
GLPT (Note 5)	4,019.8	2,939.4	1,057.6	
H1N (Note 2)	240,274.0	232,874.3	201,107.9	
All Transmitters	245,064.3	236,695.8	202,910.3	

Transmitter	Uniform Rates and Revenue Allocators			
	Network	**Line Connection**	**Transformation Connection**	
Uniform Transmission Rates ($/kW-Month)	**3.61**	**0.75**	**1.85**	
FNEI Allocation Factor	**0.00441**	**0.00441**	**0.00441**	
CNPI Allocation Factor	**0.00321**	**0.00321**	**0.00321**	
GLPT Allocation Factor	**0.02455**	**0.02455**	**0.02455**	
H1N Alocation Factor	**0.96783**	**0.96783**	**0.96783**	
Total of Allocation Factors	1.00000	1.00000	1.00000	

Note 1: Proposed Hydro One Networks (H1N) 2013 Revenue Requirement
Note 2: Proposed Hydro One Networks (H1N) 2013 Charge Determinants
Note 3: FNEI Rates Revenue Requirement and Charge Determinants per Board Decision and Order on EB-2009-0387 dated December 9, 2010.
Note 4: CNPI Rates Revenue Requirement and Charge Determinants per Board Decision on RP-2001-0034 dated December 11, 2001.
Note 5: GLPT Rates Revenue Requirement and Charge Determinants per Board Decision and Order on EB-2010-0291 dated on December 19, 2011.
Note 6: Calculated data in shaded cells.

APPENDIX C

DRAFT

Summary Uniform Transmission Rates and Revenue Disbursement Factors
for Rates Effective January 1, 2014

Transmitter	Revenue Requirement ($)			
	Network	Line Connection	Transformation Connection	Total
FNEI (Note 3)	$3,870,865	$799,421	$1,656,804	$6,327,089
CNPI (Note 4)	$2,821,857	$582,777	$1,207,808	$4,612,443
GLPT (Note 5)	$21,564,340	$4,453,521	$9,229,946	$35,247,808
H1N (Note 1)	$890,953,721	$184,001,982	$381,345,079	$1,456,300,783
All Transmitters	$919,210,784	$189,837,701	$393,439,638	$1,502,488,123

Transmitter	Total Annual Charge Determinants (MW)			
	Network	Line Connection	Transformation Connection	
FNEI (Note 3)	187.1	213.5	76.2	
CNPI (Note 4)	583.4	668.6	668.6	
GLPT (Note 5)	4,019.8	2,939.4	1,057.6	
H1N (Note 2)	234,635.3	227,880.9	196,795.3	
All Transmitters	239,425.6	231,702.4	198,597.7	

Transmitter	Uniform Rates and Revenue Allocators			
	Network	Line Connection	Transformation Connection	
Uniform Transmission Rates ($/kW-Month)	**3.84**	**0.82**	**1.98**	
FNEI Allocation Factor	**0.00421**	**0.00421**	**0.00421**	
CNPI Allocation Factor	**0.00307**	**0.00307**	**0.00307**	
GLPT Allocation Factor	**0.02346**	**0.02346**	**0.02346**	
H1N Alocation Factor	**0.96926**	**0.96926**	**0.96926**	
Total of Allocation Factors	1.00000	1.00000	1.00000	

Note 1: Proposed Hydro One Networks (H1N) 2014 Revenue Requirement
Note 2: Proposed Hydro One Networks (H1N) 2014 Charge Determinants
Note 3: FNEI Rates Revenue Requirement and Charge Determinants per Board Decision and Order on EB-2009-0387 dated December 9, 2010.
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Note 5: GLPT Rates Revenue Requirement and Charge Determinants per Board Decision and Order on EB-2010-0291 dated on December 19, 2011.
Note 6: Calculated data in shaded cells.

EB-2012-0031 – SETTLEMENT AGREEMENT – APPENDIX A

APPENDIX A

LIST OF APPROVALS SOUGHT

1. An Order pursuant to Section 78 of the *Ontario Energy Board Act* approving 2013 and 2014 Revenue Requirement and rates for the transmission of electricity to be implemented January 1, 2013 and January 1, 2014.

2. As a result of the Settlement Proposal, Hydro One Networks seeks approval of a revenue requirement of $1,446 million and $1,537 million for the test years 2013 and 2014, respectively. This results in an increase in Hydro One Transmission's Rates Revenue Requirement of 0% and 7.1%, respectively, reflecting an estimated increase on the average customer's total bill of 0.0% in 2013 and 0.6% in 2014. The estimate of the impact on a customer's total bill assumes commodity costs of 7.2¢/kWh and that transmission represents 7.9% of an average distribution connected customer's total bill.

3. Hydro One Networks seeks approval of regulatory assets totaling ($30.3) million as at December 31, 2012. Hydro One seeks approval to refund this balance over a two year period and to reduce the annual revenue requirement accordingly. Hydro One proposes to refund an amount that will ensure the overall rate increase in 2013 will be 0.0% and to refund any remaining balance to customers in 2014.

4. Hydro One Networks seeks approval to continue the following deferral accounts including, the Excess Export Service Revenue Account, the External Secondary Land Use Revenue Variance Account, the External Station Maintenance and E&CS Revenue Variance Account, the Tax Rate Changes Account, the Rights Payments Variance Account, the Pension Cost Differential Account, and the East-West Tie account.

5. For 2013 and 2014, Hydro One Transmission is requesting that the Board approve the establishment of four new deferral accounts, the External Revenue – Partnership Transmission Projects Account, the Long-Term Transmission Future Corridor

Acquisition and Development Account, the Other External Revenues Variance Account, the LDC CDM and Demand Response Variance Account.

6. Hydro One Transmission is also requesting the discontinuance effective January 1, 2013 of the Deferred Export Service Credit Revenue Account, the Long Term Project Development Costs Account, the Impact for Changes in USGAAP Account and the USGAAP Incremental Transition Costs Account.

7. Hydro One Networks also requests the Board approve several proposed modifications to the current Transmission Connection Procedures, which were approved by the Board in EB-2006-0189 to reflect the current electricity market conditions with respect to the connection of renewable generation. The proposed changes relate to a number of sections in Hydro One Transmission's Connection Procedures including: 1) the Customer Connection Process, 2) Security Deposit Procedure, 3) Customer Impact Assessment Procedure, 4) Schedule of Charges and Fees, and 5) Connection Process Timelines. Hydro One will also incorporate further revisions to the proposed connection procedures as outlined in parts f) and j) of the interrogatory response to in Exhibit I, Tab 24, Schedule 1.03, Staff 95.

8. Approval of Hydro One's Green Energy Plan for 2013 and 2014.

EB-2012-0031 – SETTLEMENT AGREEMENT – APPENDIX B

	Filing (Blue Page)			**Reduce 2013 capex/in-service by $120M; decrease OM&A by $13M & $10M; increase 2014 ext. revenue by $4.8M; increase tax credit by $1.3M & $1M; adjust rider refund timing; updated LVSG**			**Updated Cost of Capital (DRAFT RATE ORDER VIEW)**			**Updated Export Credit to get to 0% in 2013**		
Draft Rate Increases	ROE	ROE	ROE	ROE	ROE	ROE	ROE	ROE	ROE	ROE	ROE	ROE
October 29, 2012	9.42%	9.16%	9.44%	9.42%	9.16%	9.44%	9.42%	8.93%	9.28%	9.42%	8.93%	9.28%
	2012	2013	2014	2012	2013	2014	2012	2013	2014	2012	2013	2014
Revenue requirement												
OM&A		453.3	459.7		440.3	449.7		440.3	449.7		440.3	449.7
Depreciation on fixed assets		315.1	335.8		313.4	332.5		313.4	332.5		313.4	332.5
Capitalized depreciation		(9.8)	(9.8)		(9.8)	(9.8)		(9.8)	(9.8)		(9.8)	(9.8)
Asset removal costs		35.3	41.9		35.3	41.9		35.3	41.9		35.3	41.9
Other amortization		6.1	6.9		6.1	6.9		6.1	6.9		6.1	6.9
Return on debt		268.3	283.8		266.5	280.5		270.2	280.3		270.2	280.3
Return on equity		344.9	379.5		342.7	375.1		334.1	368.7		334.1	368.7
Income tax		46.4	55.2		46.2	55.7		43.1	53.4		43.1	53.4
AFUDC		4.9	4.8		4.9	4.8		5.0	4.8		5.0	4.8
Revenue requirement	1,418.4	1,464.5	1,557.7	1,418.4	1,445.7	1,537.2	1,418.4	1,437.7	1,528.4	1,418.4	1,437.7	1,528.4
	5.4%	3.2%	6.4%	5.4%	1.9%	6.3%	5.4%	1.4%	6.3%	5.4%	1.4%	6.3%
Less: Non-rate revenues	(28.7)	(31.6)	(31.8)	(28.7)	(31.6)	(36.6)	(28.7)	(31.6)	(36.6)	(28.7)	(31.6)	(36.6)
	1,389.7	1,432.9	1,525.9	1,389.7	1,414.1	1,500.6	1,389.7	1,406.1	1,491.8	1,389.7	1,406.1	1,491.8
	5.9%	3.1%	6.5%	5.9%	1.8%	6.1%	5.9%	1.2%	6.1%	5.9%	1.2%	6.1%
Less: Export revenue credit	(16.0)	(31.0)	(30.1)	(16.0)	(31.0)	(30.1)	(16.0)	(31.0)	(30.1)	(16.0)	(27.0)	(34.1)
	1,373.6	1,401.9	1,495.8	1,373.6	1,383.1	1,470.5	1,373.6	1,375.2	1,461.7	1,373.6	1,379.2	1,457.7
	6.0%	2.1%	6.7%	6.0%	0.7%	6.3%	6.0%	0.1%	6.3%	6.0%	0.4%	5.7%
Less: "Tx Riders"	-	(15.1)	(15.1)	-	(4.5)	(25.7)	-	-	(30.3)	-	-	(30.3)
	1,373.6	1,386.8	1,480.6	1,373.6	1,378.6	1,444.8	1,373.6	1,375.2	1,431.5	1,373.6	1,379.2	1,427.5
	6.6%	1.0%	6.8%	6.6%	0.4%	4.8%	6.6%	0.1%	4.1%	6.6%	0.4%	3.5%
Add: LVSG	11.5	11.7	12.5	11.5	11.7	12.2	11.5	11.7	12.2	11.5	11.6	12.1
Rates Revenue Requirement	1,385.1	1,398.5	1,493.1	1,385.1	1,390.3	1,457.0	1,385.1	1,386.8	1,443.6	1,385.1	1,390.8	1,439.5
	6.6%	1.0%	6.8%	6.6%	0.4%	4.8%	6.6%	0.1%	4.1%	6.6%	0.4%	3.5%
Estimated impact of load reduction	-1.2%	0.4%	**-2.3%**	-1.2%	0.4%	**-2.3%**	-1.2%	0.4%	**-2.3%**	-1.2%	0.4%	**-2.3%**
Assumed Rate Impact	**7.8%**	**0.6%**	**9.1%**	**7.8%**	**0.0%**	**7.1%**	**7.8%**	**-0.3%**	**6.4%**	**7.8%**	**0.0%**	**5.8%**
Rate Base		9413.5	10050.9		9353.4	9933.8		9353.4	9933.8		9353.4	9933.8

Transmission Connection Procedures

Transmission Connection Procedures

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HYDRO ONE NETWORKS INC.
TRANSMISSION CONNECTION PROCEDURES

1.0 INTRODUCTION

On July 25, 2005 the Ontario Energy Board (the Board) issued revisions to the Transmission System Code (the Code). The revised Code came into force on August 20, 2005. The Code directs all licensed transmitters in Ontario to file with the Board, within one year of the revision date, a transmitter's connection procedures referred to in section 6.1.3 of the Code. Section 6.1.4 states that a transmitter's connection procedures referred to in section 6.1.3 shall include the following:

(a) a Total Normal Supply Capacity Procedure;
(b) an Available Capacity Procedure;
(c) a Security Deposit Procedure;
(d) a Customer Impact Assessment Procedure;
(e) an Economic Evaluation Procedure;
(f) a Contestability Procedure;
(g) a Reconnection Procedure;
(h) a Dispute Resolution Procedure;
(i) an obligation on the transmitter to provide a customer with the most recent version of the plans required by section 6.3.6 that cover the applicable portion of its transmission system;
(j) a schedule of all charges and fees that may be charged by the transmitter and that are not covered by the transmitter's Rate Order; and
(k) reasonable timelines within which activities covered by the procedures referred to in paragraphs (a) to (g) and (i) must be completed by the transmitter or the customer, as applicable, including typical construction time for facilities.

Hydro One has developed these connection procedures to meet the direction in the Code,

Stakeholder Consultations:

On May 23, 2006 Hydro One provided a presentation on its draft customer connection procedures to the company's Customer Advisory Board (CAB). The CAB comprises representatives from Hydro One's main customer groups, including representation from:

- a number of large industrial customers and AMPCO
- a number of LDCs and the EDA
- APPrO
- the Consumers Council of Canada (CCC)
- the Ontario Federation of Agriculture (OFA)
- the Federation of Ontario Cottagers' Associations (FOCA)

Some comments on the procedures were provided at the meeting and members were also invited to submit written comments to Hydro One over the following several weeks.

Hydro One also presented the proposed connection procedures to the EDA Operations Council meeting on June 7, 2006. The EDA published a notice in its publication, EDA Weekly - Volume 6, Issue 24 – June 14, 2006. The notice explained that the proposed transmission connection procedures will be filed with the OEB and referenced a copy of the presentation from the Operations Council meeting. The notice invited members to provide comments regarding the proposed procedures to Hydro One by June 23, 2006. A copy of the Presentation was also sent to London Hydro for their review and comments, as London Hydro is not a member of the EDA. No comments were received by Hydro One.

Hydro One's Transmission Connection Process

Hydro One has historically documented its transmission connection process to provide connection applicants with an outline of the steps involved for processing requests to connect to its transmission system or to modify existing connections. The process document includes a number of detailed process maps and the descriptions of the steps in the process. The detailed maps and descriptions are available on Hydro One Networks' website (www.HydroOneNetworks.com) for the information of customers or the Board.

In accordance with the Market Rules, anyone planning to establish or modify a connection to the IESO-controlled grid must obtain approval through the IESO's Connection Assessment and Approval (CAA) process. The CAA process allows the IESO to assess the impact of new or modified connections on the IESO-controlled grid. For complete details of the IESO's CAA process, refer to the IESO's "Market Administration Manuals, Part 2.10: Connection Assessment and Approval."

Hydro One's customer connection process is separate from the IESO's CAA process. However the two organizations work together with connection applicants to process applications. The customer connection process is initiated once a connection applicant requests a connection to the Hydro One transmission system. The applicant may elect to have a connection feasibility study carried out by its consultants or the IESO to identify general issues and concerns associated with a connection proposal that may affect its feasibility and to assist in defining the preferred connection alternative and arrangement of facilities at the transmission point of connection. Hydro One may also be retained, at cost, to carry out a connection feasibility study prior to initiating the customer connection process.

All connection applicants that register with the IESO for the CAA process must also register with Hydro One to estimate the cost and to schedule the resources needed to complete the connection to the Hydro One transmission system.

The customer connection process is summarized below in Figure 1.

Figure 1:
Hydro One Customer Connection Process

Connection Application (Phase 1)
- Apply for New or Modified Tx Connection
- Clarify Information
- Provide Initial Consultation & Preliminary Advice
- Provide Relevant Tx System Plans
- Proceed with Project?
- Determine if Project Is Materially Impactive
- Define Project Scope & Proceed in Parallel with IESO-CAA

Customer Impact Assessment (CIA) (Phase 2)
- Determine if CIA Is Required
- Execute CIA Study Agreement
- Carry Out CIA (Examine Project Impacts on (i) Short Circuit (ii) Voltage Performance (iii) Supply Reliability (iv) Supply Capacity)
- Execute Preliminary Engineering Agreement
- Issue Draft CIA Report for Comment
- Issue Final CIA Report

Connection Estimates (Phase 3)
- Request Connection Estimates
- Agree on Estimate Scope of Work
- Execute Pre-CCRA Long lead Items Agreement
- Review Customer Connection Electrical Design Package
- Determine Contestable & Uncontestable Connection Work
- Issue Technical Standards & Determine Project Costs
- Determine Customer Capital Contribution Requirements
- Submit Connection Estimates & Other Required Information
- Decide on Connection Facility Ownership

Connection Approval (Phase 4)
- Provide Mandatory Pre-requisites to Proceed with Connection
- Complete CCRA
- Receive Security Deposit(s)
- Execute CCRA
- Acquire Necessary Regulatory Approvals (i.e. MOE, OEB, ESA, Easements/Property, etc.)
- Modify Connection to Accommodate Regulatory Approvals, as Appropriate
- Initiate Connection Agreement Negotiations

Design & Build (Phase 5)
- Award Work
- Use Technical Standards & Commissioning Requirements provided by Hydro One
- Confirm Requirements & Deliverables
- Complete Detailed Engineering & Project Design
- Procure Equipment & Material & Obtain Construction Approvals
- Construct Facilities

Commissioning (Phase 6)
- Finalize Connection Agreement
- Commission Hydro One Facilities
- Submit Customer Commissioning Plan 30 Business Days in Advance
- Commission Customer Built Facilities
- Transfer Customer Built Facilities to Hydro One Ownership, as Appropriate
- Revise CCRA Based on Actual Connection Costs
- Submit As-Built Prints
- Manage CCRA & Connection Agreement

Customer Or Connection Applicant

IESO
Customer Assessment & Approval Process

(Optional) Feasibility Study

System Impact Assessment or Expedited System Impact Assessment, As Appropriate

Required Path

Optional Path

Hydro One's "Customer Connection Process" and the Independent Electrical System Operator (IESO) "Connection Assessment and Approval Process" are separate processes that must both be implemented to obtain the necessary transmission system connection approvals.

Any Customer wishing to establish or modify a connection to Hydro One's transmission system must apply / register with both Hydro One and the IESO. However, Customers are strongly advised to initiate discussions with Hydro One prior to applying to the IESO for a connection assessment.

2.0 HYDRO ONE CONNECTION PROCEDURES

Section 2.1

TOTAL NORMAL SUPPLY CAPACITY PROCEDURE

INTRODUCTION

Hydro One's Total Normal Supply Capacity Procedure was developed to meet the requirements of section 6.2.7 of the Transmission System Code (the Code).

Glossary

Total Normal Supply Capacity: The maximum amount of load that can be supplied by a connection facility. The total normal supply capacity at a connection facility is derived from the electrical rating of that facility. Each connection facility is classified as either a summer- or winter-peaking facility. The total normal supply capacity at a connection facility is calculated based on this classification.

Transmission connection facilities: Transmission connection facilities consist of transformation connection facilities and line connection facilities. As such, transformer stations and line taps dedicated to serving a limited group of transmission customers are considered to be transmission connection facilities. All references in the procedure apply to both transformation and line connection facilities unless otherwise noted.

PROCEDURE PHASES

Phase 1: Obtain Asset Information

The first step in the procedure is to compile a listing of all transmission connection pool facilities. Two separate lists are extracted from existing databases to identify transformation connection facilities and line connection facilities.

Phase 2: Compute Total Normal Supply Capacity

The objective of this phase is to determine the connection facility's total normal supply capacity. Total normal supply capacity is established differently for transformers and lines as outlined below, due to the inherent characteristics and configurations of each asset group. It is important to note that access to the capacity may be constrained by limits associated with the availability of other related facilities (e.g. feeder breaker positions, bus capacity, etc.) and may require an incremental capital investment. Specific details of the costs associated with utilization of this capacity will be provided by Hydro One on request.

Transformation Connection Facility

The total normal supply capacity for a transformation connection facility will be determined as follows:

- **Single transformer supply**: The total normal supply capacity will be the continuous rating of the subject transformer (i.e. the transformer nameplate rating with full cooling).
- **Dual transformer supply**: The total normal supply capacity will be the 10-day limited time rating (LTR) of the more limiting transformer (assuming loss of the larger one).

- **More than 2 transformers supplying a common bus**: The total normal supply capacity will be the sum of the 10-day LTR's of the "n -1" (i.e. the number of transformers minus 1) more limiting transformers (assuming loss of the largest one as the worst case).
- The critical season (winter or summer) would be indicated.
- The method applies to 3-phase transformers and single-phase transformers considered as three-phase transformer equivalents.
- Unless otherwise noted, a power factor of 90% is assumed.
- Hydro One may update the LTR value where new information that impacts the value becomes known.

Line Connection Facility

The total normal supply capacity for a line connection facility will be determined as follows:

- **Single circuit supply**: The total normal supply capacity will be the more limiting of the continuous rating of the subject line or the maximum load that can be supplied while meeting acceptable voltage levels as established by Hydro One.
- **Dual circuit supply**: The total normal supply capacity will be the more limiting of the continuous rating of the more limiting circuit or the maximum load that can be supplied with one critical line out of service while meeting acceptable voltage levels as established by Hydro One.
- The normal connection configuration will be used to determine total normal supply capacity.
- The critical season (winter or summer) will be indicated.
- Unless otherwise noted, a power factor of 90% is assumed.

Phase 3: Notify Customers of Total Normal Supply Capacity

The total normal supply capacity at a connection facility will be provided to customers as part of the available capacity notification (see Hydro One's Available Capacity Procedure). The information will be made available to customers for their relevant facilities in accordance with the requirements of the Code.

Customers are to confirm with Hydro One that the identified capacity for a particular facility is still valid at any particular point in time, and furthermore, that the figure is suitable to be used for that customer's particular application.

Phase 4: Maintain Data

The total normal supply capacity at each facility will be updated as required due to changes, additions and removal of facilities. The updated values will be input into Hydro One's available capacity process, which will initiate a review of the available capacities at the relevant connection facilities. Hydro One reserves the right to change the total normal supply capacity value at a connection facility at any time where new information impacting that value becomes known.

Section 2.2

AVAILABLE CAPACITY PROCEDURE

INTRODUCTION

Hydro One's Available Capacity Procedure was developed to meet the requirements of section 6.2.11 of the Transmission System Code (the Code). The procedure applies to customers that are connected and supplied directly from a transmission connection facility.

Glossary

Available Capacity: The available capacity at a connection facility is derived from the assigned capacities for all customers at that facility and the facility's total normal supply capacity. As indicated in the Total Normal Supply Capacity Procedure, each connection facility is classified as either a summer or winter peaking facility and hence the available capacity at a connection facility is also calculated based on this classification. The available capacity for a summer-peaking facility is the facility's total normal supply capacity in summer less the total assigned capacity at that facility. Similarly, the available capacity for a winter peaking facility is the facility's total normal supply capacity in winter less the facility's total assigned capacity.

Transmission connection facilities: Transmission connection facilities consist of transformation connection facilities and line connection facilities. As such, transformer stations and line taps dedicated to serving a limited group of transmission customers are considered to be transmission connection facilities. All references in the procedure apply to both transformation and line connection facilities unless otherwise noted. A transformer station will be understood to mean all transformation facilities related to one or more transformers acting together as a group to supply a common set of distribution feeders. A line connection facility may be a section of a transmission line dedicated to serving one or more transformation connection facilities or any contiguous subset of such section as determined by Hydro One.

PROCEDURE PHASES

Phase 1: Initiate Available Capacity Process

In this phase, the available capacity process is initiated either by a customer requesting Hydro One to assign available capacity to the customer (Step 1.1 below) or by Hydro One performing its own internal monitoring of the available capacity at a connection facility (Step 1.2 below).

Step 1.1: Customer application for available capacity will initiate the available capacity process.

A customer requiring additional capacity assignment at a connection facility will submit a customer application for available capacity to Hydro One. The application will be specific to a particular connection facility which will be identified in the application.

The customer's application will contain general company and contact information, as well as technical loading and capacity data, including amount of available capacity being requested, anticipated timeframe for the requested capacity, nature of the associated load and a 5-year load forecast. The load forecast will be for the customer's total peak load at the connection facility.

Step 1.2: Periodic monitoring of available capacity will initiate the available capacity process.

From time to time as required, Hydro One will initiate a review of the available capacity remaining at a connection facility to determine if the facility is approaching capacity.

Phase 2: Determine Available Capacity

In this phase, the capacity remaining at a connection facility that will be available for assignment to customers will be determined.

Step 2.1: Identify all customers at a connection facility**.**

For a given connection facility, all customers at the facility will be identified and listed. In this context, a "customer" will be understood to mean a transmission load customer, as defined in sections 2.0.18 and 2.0.40 of the Code. As such, a customer may be a local distribution company (LDC) or an industrial customer currently supplied by the connection facility. An LDC or industrial customer with facilities that are not currently connected but are intended to be connected to the connection facility is also a customer.

Step 2.2: Identify contracted capacity for each customer.

For each customer that has a signed contract (e.g. CCRA) with Hydro One for capacity at a connection facility, the customer will be recognized to have contracted capacity. The customer's contracted capacity for a given year will be understood to mean the load identified for that year in the load forecast associated with the economic evaluation relating to the customer's contract. The capacity will be in units of MW. Unless otherwise noted, a 90% power factor will be assumed.

The customer's contracted capacity in future years is also included in the CCRA, which includes a summary of the results of the economic evaluation for all years covered in the economic evaluation period (see Section 2.5). The CCRA terminates at the end of the economic evaluation period. The customer will also be required to sign a Connection Agreement with Hydro One, which will continue to be in effect after the CCRA terminates.

Step 2.3: Identify historical load data for each customer.

For a customer without a signed contract with Hydro One for capacity at a connection facility, the customer's assigned capacity will be equal to the customer's highest rolling 3-month average peak load at that facility as per section 6.2.2 of the Code. The peak load data will be coincident with the total load for that customer at that facility only. Hydro One will compile the necessary historical load data and calculate this peak for each customer. This peak represents the customer's assigned capacity based on historical loading.

The data used will be the customer's historic monthly peak loads since May 1, 2002 or the most recent 60-month period, whichever is less, as per the Code. The data provided will represent the customer's loading under normal operating conditions and exclude any anomalies such as temporary load transfers. The data will be provided in both MW and MVA. In the absence of metering data for line connection facilities, Hydro One will determine the historic loading on a line connection facility based on historic loading data available for relevant transformation connection facilities. Where Hydro One reasonably believes that a customer is manipulating its load for the purpose of the determination of its assigned capacity, Hydro One may request that the Board review and re-determine that assigned capacity as per section 6.2.2 of the Code.

Step 2.4: Identify previous capacity assignments or capacity adjustment.

In addition to a customer's contracted capacity (where a contract exists) or the customer's assigned capacity based on historical loading (where no contract exists), any available capacity that has been assigned to a customer and that capacity has not been taken up by the customer within one year of the assignment is subject to cancellation by Hydro One, except where that capacity is part of a load forecast contained in a contract (e.g. CCRA) as per section 6.2.19 of the Code.

Step 2.5: Determine assigned capacity for each customer.

A customer's assigned capacity at a connection facility is by default the customer's assigned capacity based on historical loading (Step 2.3). However, Hydro One may apply an adjustment (Step 2.4) to the assigned capacity to arrive at an adjusted assigned capacity. The customer's final assigned capacity will be the aggregate of the customer's assigned capacity based on historical loading and any assigned capacity adjustments derived from available capacity that have been assigned to the customer and that have not been taken up by the customer or cancelled under Step 2.4. For all subsequent steps and phases, a customer's "assigned capacity" will be understood to mean the customer's final assigned capacity as determined in this step. Once capacity has been assigned to a customer, such assigned capacity will not be re-assigned without the consent of that customer, subject to the cancellation provision in Step 2.4.

Assigning capacity at a Hydro One connection facility is exclusively the role of Hydro One. A customer with assigned capacity cannot re-assign that capacity. In the event of a change of ownership of facilities from an existing customer to a new customer, Hydro One will, upon request, re-assign the capacity to reflect the change of ownership.

Step 2.6: Sum assigned capacities for all customers**.**

The total assigned capacity at a connection facility is calculated by summing the individual assigned capacities for all customers at that facility. Hydro One will take into account the normal size and shape of each customer's load, excluding anomalies such as temporary load transfers.

Step 2.7: Obtain total normal supply capacity of connection facility**.**

The total normal supply capacity of a connection facility will be obtained from the Total Normal Supply Capacity Procedure and will be in units of MW. Unless otherwise noted, a 90% power factor will be assumed.

Step 2.8: Calculate available capacity at connection facility.

The available capacity at a connection facility is calculated by subtracting the total assigned capacity at that facility from the total normal supply capacity of the facility. The available capacity will be in units of MW. Unless otherwise noted, a 90% power factor will be assumed. For transformation facilities, the available capacity reflects available transformer capacity only. Other capacity restrictions (e.g. feeder breaker positions) may limit access to the full available capacity of the transformers and will incur a cost to upgrade in order to access the transformers' full available capacity. Furthermore, the transformers' full available capacity may also be limited by feeder configurations.

Where additional feeder breakers are requested by a customer, the installation of such equipment does not constitute additional contracted capacity. The customer will have cost responsibility for the additional feeder breakers and a capital contribution is required for the full cost of installing the additional feeder breakers.

Phase 3: Assess Available Capacity

In this phase, Hydro One will assess the loading on a connection facility to determine whether the facility is approaching capacity and the need to initiate appropriate measures.

Step 3.1: Available capacity less than or equal to 25% of total normal supply capacity.

Hydro One will compare the available capacity at a connection facility with the total normal supply capacity to determine whether there is at least 25% of total normal supply capacity remaining as available capacity at that facility.

In order to conduct this assessment, Hydro One will reduce the available capacity at the facility by an amount equal to the aggregate of the capacities identified on all customer applications for available capacity at that facility. This will determine whether the available capacity at a connection facility is sufficient to meet all customer requests for additional capacity without causing the loading on the facility to approach capacity.

The loading at a facility is deemed to be approaching capacity if available capacity is less than or equal to 25% of total normal supply capacity. Where the loading at a connection facility is approaching capacity, Hydro One will conduct the steps outlined in Phase 4 of this procedure. Where loading is not approaching capacity, Hydro One will proceed based on whether any customer has applied for available capacity.

Step 3.2: Customer application for available capacity.

In the case where a customer has applied for available capacity, Hydro One will assign capacity to that customer as per Phase 5 of this procedure, based on demonstrated need and prorating of available capacity where required.

Phase 4: Implement Available Capacity Assessment

Implementation of the available capacity assessment is intended to ensure that all customers at a connection facility are informed when the loading at a facility is approaching capacity and are provided with a reasonable opportunity to make requests for any remaining available capacity. Where the loading at a facility is approaching capacity, the circumstances under which an expansion study will be initiated will also be established.

Step 4.1: Notify customers of available capacity remaining at connection facility.

Where the loading at a connection facility is approaching capacity, Hydro One will notify all customers at the facility in writing that the facility is approaching capacity and that the available capacity procedure has been triggered. Hydro One will provide this information using a Customer Notification of Available Capacity form. The form will identify the connection facility, the facility's summer/winter classification, total normal supply capacity and available capacity for the current year. Before disclosing this information, Hydro One will first obtain the consent of each customer at the connection facility to which the information pertains. Where such consent cannot be obtained, Hydro One may request guidance from the Board.

Step 4.2: Process customer applications for available capacity**.**

Upon notification that Hydro One's available capacity procedure has been triggered, a customer will have twenty (20) working days to decide whether or not to submit an application for available capacity. Applications received after this period will be considered separately from, and processed after the completion of, the current implementation of the available capacity procedure.

Step 4.3: Assess capacity needs of each customer applicant.

Hydro One's assessment of each applicant's capacity needs involves a review of the customer's historical loading, expansion plans, load forecast, and regulatory and other issues.

The required information for confirming customer need for available capacity is as follows.

- The customer must provide all the data specified in the Customer Application for Available Capacity. This includes the customer's forecast of future peak load demand.
- The customer's load forecast (1 - 5 years) must be in line with its historical usage. If this is not the case, the customer must provide information on specific expansions.
- The Customer must provide supporting documentation for its load forecast. Supporting documentation could be a letter from a senior manager or the customer's business plan.
- The Customer's expansion plan must be in line with its historical performance, the sector performance, and the general economic outlook for the province of Ontario.
- The Customer must identify all government and regulatory issues related to its request for available capacity.

Step 4.4: Initiate expansion study.

Where Hydro One deems necessary, customers will be requested to participate in an expansion study. Hydro One is not restricted to initiating an expansion study in this step of the process only as it may initiate a planning study anytime that it considers it necessary to ensure adequate supply to accommodate the assigned capacities of all customers at a connection facility. Where Hydro One proposes to initiate an expansion study on a connection facility, it will notify all customers at that facility and at adjacent facilities, and post on the appropriate website(s), a notice of Hydro One's proposal to initiate an expansion study at that facility and of the right of each notified customer to apply to Hydro One in writing to reconfigure any portion of its load to any new facility that may be constructed. Hydro One will review any such application and negotiate in good faith with the customer to determine the terms and conditions that would govern any such reconfiguration, in accordance with the all relevant provisions in the Code. An expansion study may lead to a customer contract (e.g. CCRA) for a modified or new connection facility. Upon completion of an expansion study, Hydro One will advise all previously notified customers of the available capacity on all relevant existing and new connection facilities before and after the expansion.

Phase 5: Implement Available Capacity Assignment

Hydro One will assign capacity to each customer based on the customer's need for available capacity unless Hydro One can demonstrate that the available capacity will not meet the customer's needs. When there are more than one customer applications, capacity will be assigned in proportion to each customer's respective needs, using Hydro One's criteria for assigning available capacity.

Step 5.1: Assign available capacity to each customer applicant.

Where there is more than one customer applying for available capacity at a connection facility, available capacity will be assigned in proportion to customers' demonstrated needs, as per Hydro One's criteria for assigning available capacity. The criteria are:

- The submission date of the customer application for available capacity.
- Customer's confirmed need for available capacity.
- Aggregate of the confirmed needs for all customers at a connection facility versus the facility's available capacity. If the total of the confirmed needs is greater than the available capacity, Hydro One will assign available capacity on a pro-rated basis taking the following into account:

  (a) Criticality of the customer need based on the criteria for confirming customer need for available capacity.
  (b) Timing for the confirmed need.
  (c) Type of customer.
  (d) Extenuating circumstances.

The capacity assignment will be for a fixed amount for a one-year period. Capacity will not be assigned for backup purposes. Assigned capacity will be in units of MW. Unless otherwise noted, a 90% power factor will be assumed.

Once capacity has been assigned to a customer, such assigned capacity will not be re-assigned without the consent of that customer, subject to the cancellation provision in Step 6.3. Where a customer provides its own connection facility to serve new load, the transmitter will not assign capacity on the relevant Hydro One owned connection facility to that customer in relation to the new load as per the Code.

Assigning capacity at a Hydro One connection facility is exclusively the role of Hydro One. A customer with assigned capacity cannot re-assign that capacity. In the event of a change of ownership of facilities from an existing customer to a new customer, Hydro One will, upon request, re-assign capacity to reflect the change of ownership. The one-year period identified in the cancellation provision in Step 6.3 continues to run regardless of any change in ownership.

Where capacity at a connection facility is assigned to Hydro One Distribution, Hydro One Brampton or any other entity that is a Hydro One affiliate, Hydro One will advise all customers at that facility of the capacity assignment. This requirement is regardless of whether such assignment causes the loading at the facility to approach capacity as per section 6.2.13 of the Code.

Phase 6: Implement Capacity Monitoring

In this phase, the available capacity at a connection facility is monitored on an ongoing basis. This involves monitoring the loading at the facility as well as customers' usage of their assigned capacities. Monitoring will be done on an ongoing basis and an available capacity assessment will be performed as required.

<u>Step 6.1: Maintain records of assigned capacities and available capacity.</u>

Hydro One will maintain a record of each customer's assigned capacity and the available capacity at a connection facility. Upon request, Hydro One will provide a customer with the customer's assigned capacity at a connection facility and the available capacity at that facility. To protect confidentiality, only a customer's own assigned capacity will be made available to the customer.

<u>Step 6.2: Monitor usage of assigned capacity for each customer.</u>

Hydro One will monitor each customer's monthly peak loads in MW and MVA. Hydro One will compare the customer's loading with the customer's assigned capacity as required.

<u>Step 6.3: Extend or cancel any unused assigned capacity.</u>

Where available capacity has been assigned to a load customer and that capacity has not been taken up by the customer within one year of the assignment, Hydro One will cancel the assignment as per section 6.2.19 of the Code. This capacity will be treated as available capacity and Hydro One will notify all other customers served by the connection facility of the cancellation of the assignment. Hydro One may, upon request, extend the capacity assignment to beyond the one-year period where circumstances warrant. This step does not apply to contracted capacity that is part of a load forecast contained in a contract.

Where unused assigned capacity is extended beyond the one-year period for Hydro One Distribution, Hydro One Brampton or any other customer that is a Hydro One affiliate, Hydro One will notify all customers at the connection facility of the extension as per section 6.2.21 of the Code.

Step 6.4: Monitor usage of assigned capacity for potential by-pass

Where Hydro One determines that a customer has transferred assigned capacity without notifying Hydro One or the OEB of its intention to by-pass an existing connection facility, Hydro One will notify the customer and the OEB of a potential by-pass situation and the revenues lost by Hydro One on the connection facility in proportion to the load transferred for the given time period. If the customer does not intend to by-pass Hydro One's facilities, the customer must notify Hydro One and the OEB within 30 days of receiving Hydro One's notification of potential by-pass, that it has no intention of by-passing Hydro One's connection facility. In addition, the customer will transfer the load back to the existing Hydro One connection facility within an agreed time period and provide Hydro One with a payment for the lost revenues, adjusted appropriately to reflect the time value of money.

Projection by Hydro One of available capacity for future years.

Hydro One may, from time to time, and depending on its own information needs and those of customers, prepare a projection of available capacity for a future year or years. The methodology for making such a projection would be similar to that described in Phase 2 above, but would by necessity be based on best available information and assumptions, some of which are described below.

- For a given connection facility, any projections would be based on estimates and assumptions regarding transmission customers who may be connected to the facility in future years, including assumptions about any customers who are not currently connected but may become connected in the future.
- For each customer that has a signed contract (e.g. CCRA) with Hydro One for capacity at a connection facility, the projection will include the contracted capacity for future years. Where information exists about customers who may in the future have such a contract, assumptions and estimates will be made about their future contracted capacity.
- For customers without a signed contract with Hydro One for capacity at a connection facility, the customer's assigned capacity in the future will be estimated based on the projected highest rolling 3-month average peak load at that facility as per section 6.2.2 of the Code (ie what would eventually become the customer's "historical loading").
- Information regarding capacity cancellations, adjustments and additional requirements will likely not be available and hence would not be reflected in such projections.
- The total assigned capacity at a connection facility would be projected by summing the individual assigned capacities for all customers at that facility.
- The total normal supply capacity of a connection facility would be projected as well, based on best available planning information. The projected future available capacity would then be estimated by subtracting the estimated future assigned capacity from the projected total normal supply capacity of the facility.

While the projection of future available capacity is intended to be helpful to Hydro One and to its customers, it must be noted that such estimates are not required under the Transmission System Code, and given the quality of the information used to prepare them, they should not be relied upon for planning purposes.

Section 2.3

SECURITY DEPOSIT PROCEDURE

INTRODUCTION

Hydro One's Security Deposit Procedure was developed to meet the requirements of section 6.3.11 of the Transmission System Code (the Code). The purpose of the security deposit is to provide Hydro One with some means to mitigate risk to transmission connection pool customers during the construction phase of a connection. Hydro One has the right under the Code to retain all or part of the Security Deposit when it has expended funds for a new connection to its transmission system or made modifications to its transmission system to accommodate a customer and the customer does not connect or fails to reimburse Hydro One for funds expended on its behalf.

Glossary

<u>Agreement:</u> means an agreement made between the customer and Hydro One where Hydro One is required to:

(i) order long-lead time equipment
(ii) perform engineering work; and/or
(iii) construct new or modified network or connection facilities,

in relation to a connection application from the customer where new or modified network or connection facilities need to be constructed.

<u>Material Change in Financial Risk:</u> Consistent with the definitions in the Ontario Securities Act (R.S.O. 1990), "material change in financial risk" means a "material change" or "material fact" as defined below:

"Material change"
(i) a change in the business, operations or capital of the connecting customer or its corporate parent (where a parental guarantee is being provided) that would reasonably be expected to have a significant effect on the market price or value of any of the securities of the connecting customer or its corporate parent, or that would be considered important by a reasonable investor.
(ii) a decision to implement a change referred to in subclause (i) made by the board of directors or other persons acting in a similar capacity or by senior management of the connecting customer or its corporate parent who believe that confirmation of the decision by the board of directors or such other persons acting in a similar capacity is probable.

"Material fact" when used in relation to a connecting customer or its corporate parent, means a fact that would reasonably be expected to have a significant effect on the market price or value of any of its securities; ("fait important")

SECURITY DEPOSIT POLICY

Requirement for Security Deposit:

Hydro One may require each generator customer and load customer to provide a security deposit at or before the time of executing a Connection and Cost Recovery Agreement (CCRA).

Amount of Security Deposit:

A. Generator and Load Customer
Table 1 prescribes the amount of security that a Generator or Load Customer will be required to provide Hydro One with respect to new or modified connection or network facilities.

B. Customer Requiring Capacity in the Future
In accordance with section 6.3.9 of the Code, the amount of the capital contribution to be obtained from the current customer and the amount or value of the security deposit to be collected from the future customer shall be determined using the economic evaluation method approved by the Board as set out in section 6.5 of the Code, the load forecasts of both customers and the methodology for attributing that capital contribution as described in sections 6.3.14, 6.3.15 or 6.3.16 of the Code.

Form of Security Deposit:

The Customer shall provide any required security deposit in the form of cash, letter of credit or surety bond, or a combination thereof or such other form on which the customer and Hydro One may agree. If the Customer has an affiliate with a good credit rating and the affiliate is willing to provide a guarantee towards the Customer's indebtedness, Hydro One may consent to the use of the affiliate's credit information when determining the Customer's security deposit requirements, provided that if the Customer or affiliate experiences a material change in financial risk during the construction phase of the project or prior to the in-service date, the Customer must advise Hydro One within 5 business days of the change, and Hydro One shall have the right to require an additional security deposit. The additional security deposit at the Customer's option may be in the form of cash, letter of credit or surety bond, or a combination thereof. The customer shall have 5 business days to comply with Hydro One's request.

Security Deposits in the Form of Cash

The Code states in section 6.3.11 that when a customer provides all or any portion of a security deposit in the form of cash, upon returning the security deposit, Hydro One shall pay interest to the customer at the following rates:

(a) for the period between the date on which the security deposit was provided by the customer and the date on which the security deposit is required to be returned by Hydro One, at the average over the period of the Prime Business Rate as published on the Bank of Canada website, less two percent; and
(b) for the period after the date on which the security deposit is required to be returned by Hydro One, the Prime Business Rate as published on the Bank of Canada website, plus two percent.

Right to Retain All or Part of a Security Deposit

Hydro One may retain all or a part of a security deposit that has been given in relation to the construction or modification of connection or network facilities in any one or more of the following circumstances:

(a) where the customer subsequently fails to connect its facilities to Hydro One's new or modified connection facilities;
(b) where the customer terminates an Agreement or Hydro One terminates an Agreement as a result of a breach of the Agreement by the Customer;
(c) where the customer fails to make any payment due under the terms of an Agreement;
(d) to remedy any non-financial breach by the customer of an Agreement made by the parties in relation to the construction or modification of connection or network facilities.

Hydro One shall not otherwise retain a security deposit given in relation to the construction or modification of network facilities unless the Board has first determined under section 6.3.5 of the Code that exceptional circumstances exist so as to reasonably require the customer to make a capital contribution for the construction or modification of network facilities.

Returning Security Deposits

Hydro One shall return security deposits in any of the following circumstances:

(a) if the security deposit is in the form of cash, Hydro One shall return the security deposit to the customer, together with interest, less the amount of any capital contribution owed by the customer, once the customer's facilities are connected to Hydro One's transmission facilities;
(b) if the security deposit is in a form other than cash, Hydro One shall return the security deposit to the customer once the customer's facilities are connected to Hydro One's transmission facilities and any capital contribution owing has been paid;
(c) pursuant to section 6.3.5, where a customer requests that Hydro One not commence with construction pending direction from the Board, Hydro One must promptly return to the customer any outstanding security deposit related to the construction of the new or modified connection, unless the customer and Hydro One agree otherwise, less any expenditures made or committed by Hydro One prior to the request.

For customers requiring capacity in the future included under section 2.2 (B) of this procedure, Hydro One shall return security deposits in any one or more of the following circumstances:

(a) where the security deposit is in the form of cash, Hydro One shall return the security deposit to the future customer at the time of connection of its facilities to the connection facility, together with any interest owing, less the amount of the future customer's capital contribution;
(b) where the security deposit is in a form other than cash, the transmitter shall return the security deposit to the future customer upon receipt of the future customer's capital contribution;
(c) when a future customer requiring capacity provided security in relation to network costs and subsequently requests that Hydro One not commence with construction, pending direction from the Board under section 6.3.5 of the Code, unless the customer and Hydro One agree otherwise.

Additional Security Deposits

A customer may be required to provide additional security deposits at any time after Hydro One has executed an Agreement if (i) the customer is in default of a term of such an agreement and has not remedied the default within the cure period specified in the agreement or, if no cure period is specified in the agreement, a reasonable cure period; or (ii) if there is a material change in financial risk associated with a proposed new or modified connection. When a customer becomes aware of a material change in financial risk it must advise Hydro One of the change within 5 business days. Failure to do so will be considered a material breach of the agreement.

In a case where more than one customer triggers the need for a transmission upgrade, a customer may be required to provide an additional security deposit or extend the term of a security deposit after Hydro One has executed Agreements and collected initial security deposits. This would occur when a customer's proportional share of the upgrade cost increases because of other customer projects being delayed or cancelled that would have been contributors to the upgrade as originally planned and calculated in the Agreements.

Table 1:
Security Deposit Requirement During Construction for Generator and Load Customers

Credit Rating	Security Deposit Requirement	Rationale for Security Amount
AAA- and above, and LDC's with an acceptable credit rating	None	Highest credit rating. Long term stability supported by municipal tax base.
BBB- to AA+ (investment grade)	25% of MNE	Good credit rating.
BB- to BB+ (below investment grade)	50% of MNE	Fair credit rating just below investment grade, possibly caused by temporary or cyclical factors.
B+ or below, or unrated	100% of MNE	Low or no credit rating.
Future Customers (including LDC's) (Section 6.3.9 of the Code)	100% of incremental costs required to install additional capacity	Up to 5 year lead time for connection requires security deposit if customer does not connect.

Maximum Net Exposure (MNE) is equal to Hydro One's estimated Connection and Network Costs, less Capital Contribution. Security deposit requirements may be reduced if cost recovery is reasonably assured through confirmation by the OPA, IESO, or OEB, or if customer credit-worthiness is established through means other than a bond rating, such as Altman-Z or Kaplan-Urwitz credit scores or other means. Any adjustments to the security deposit requirements are at Hydro One's sole discretion.

PROCESS OVERVIEW

The process for establishing security deposits integrates with the over-all customer connection process and is usually done in conjunction with the development of a Connection and Cost Recovery Agreement (CCRA). In situations where it is necessary to advance work or order equipment to meet critical in-service dates, Hydro One may consider proceeding with a letter agreement requiring a security deposit for 100% of the related costs minus any advance payments made by the customer prior to signing a CCRA. The letter agreement will include a date by which the CCRA must be signed.

Customer Application

When a customer submits a connection application to Hydro One, after the customer and Hydro One have agreed to the scope of the project and a Customer Impact Assessment has been completed, Hydro One will provide the customer with an estimated cost of the work to complete the connection. Included with the estimate will be information on whether a security deposit is required and if required, the amount of the security deposit. The amount of the security deposit will be affected by the amount of contestable work the customer elects to carry out on its own or through a third party. The customer has an opportunity subsequent to receiving this information to decide if it wants to proceed with the project or not. If the customer decides to proceed, a CCRA is negotiated between the customer and Hydro One.

Security Deposit Terms within a Connection and Cost Recovery Agreement

A CCRA contains the terms of the agreement between the customer and Hydro One for the construction and connection to a new or modified facility, including the terms of its financial repayment. It includes the scope of the project and the work each party is responsible for completing. The estimated cost of work and which group is responsible for paying those costs are identified in the Agreement.

Where costs for construction or modification of connection or network facilities can be attributed to more than one customer requiring the new connection or modification, the total shared connection and network costs will be allocated on a prorated "per MW" basis as a percentage of the total capacity between the customers requiring the new or modified connection, or on such other basis as may be agreed to by the parties. For example, assuming each requires its own dedicated connection facilities, generator A with a capacity of 200MW and generator B with a capacity of 300MW for a total of 500MW would share network costs on a basis of 40% (200/500) for generator A and 60% (300/500) for generator B.

The amount of security deposit to be paid will be stipulated in the CCRA, as well as when it will be paid and the rules concerning how and when it is returned or retained by Hydro One in accordance with this document and the Code. The security deposit will normally be paid by the time the customer signs the CCRA.

Security Deposits and Progress Payments during Project Construction

During the construction phase, costs will be incurred by Hydro One on behalf of the customer. Where there is a capital contribution required, the customer will be expected to make progress payments towards the capital contribution in accordance with an agreed payment schedule in the CCRA. The progress payment schedule will typically coincide with the costs incurred for the project. The total capital contribution payable will be deducted from Hydro One's estimate of the total of the network and connection costs for the new connection or upgrade for the purposes of calculating the Maximum Net Exposure (MNE). The MNE represents Hydro One's at-risk amount during the construction phase. For the purposes of calculating the security deposit, the MNE will be a one-time only calculation and will not be adjusted on an ongoing basis unless there is a material change in the customer's financial risk. The MNE will be calculated shortly before or when the CCRA is being drafted.

The customer will provide its credit rating, taken from any of the reputable credit rating agencies, to Hydro One, which will determine the amount of security deposit required in accordance with Table 1. The amount of security deposit required using Table 1 may be reduced if cost recovery is reasonably assured through confirmation by the OPA, IESO, or OEB, or if customer credit-worthiness is established through means other than a bond rating, such as Altman-Z or Kaplan-Urwitz credit scores or other means. Any adjustments to the security deposit requirements are at Hydro One's sole discretion.

In the event of a Material Change in the Financial Risk of a customer, for example a credit-watch or lowered credit rating, Hydro One will have the right to request an increased security deposit. The customer is required to advise Hydro One of a material change in the customer's financial risk within 5 business days.

*Example of Security Deposit Calculation**:** This example is for a hypothetical customer with a BB+ credit rating with estimated network and connection costs of $20M and capital contribution of $4M. The Maximum Net Exposure (MNE) is $16M ($20M minus $4M). The security deposit requirement is 50% of the MNE which amounts to $8M. Security deposit can be provided in the form of cash, letter of credit or surety bond, as may be selected by the customer, or in such other form as the customer and the transmitter may agree.*

Return of Security Deposit after Project Completion

Hydro One will return the customer's security deposit after the construction phase of the project is complete and the customer has connected its facilities to Hydro One's transmission facilities, The CCRA will provide a timeline by which the customer is expected to have its facility in-service.

Security deposits provided by future customers will be returned after their facilities are connected to Hydro One's new or modified facilities.

Section 2.4

CUSTOMER IMPACT ASSESSMENT PROCEDURE

INTRODUCTION

Hydro One's Customer Impact Assessment (CIA) Procedure was developed to meet the requirements of section 6.4.1 of the Transmission System Code (Code). As outlined in the Code, a transmitter is required to carry out CIA studies under certain circumstances and the following points are to be noted:

1. A CIA study is limited to assessing the impact of the new or modified connection on the supply at the transmission connection/delivery points to other transmission customers. It is the responsibility of other transmission customers to determine the consequential impacts and modifications on their own electrical facilities and to advise Hydro One, the IESO, the Board and the connection applicant accordingly. Hydro One will issue a draft of the CIA report to customers who may be potentially impacted by the connection and those customers are required to provide preliminary feedback. Hydro One will include the unedited version of this feedback in the final CIA report and Hydro One will not take responsibility for the contents of the other transmission customers' feedback.
2. The decision on the level of modifications at customers' facilities that can be attributed to the new or modified connection, as well as the assignment of cost responsibility for the identified modifications, are outside the scope of this procedure.

REQUIREMENT FOR A CIA STUDY

A Customer Impact Assessment study may be required for any new or modified connection to the IESO-controlled grid. Hydro One will undertake a CIA study for all cases where (i) the connection is one for which the IESO's CAA process requires a System Impact Assessment (SIA) or (ii) Hydro One determines that the connection may have a material impact on existing customers. The scope of the CIA study and report will be project-specific, depending on the complexity of the connection project and the extent of its impact on other transmission customers. For renewable energy projects awarded by OPA in accordance with O.Reg 326/09, the joint SIA/CIA phase of the process shall be completed within 150 days after the IESO and the transmitter deem the application complete for the purpose of completing SIA/CIA studies.

Where the IESO's CAA process triggers an SIA, the CIA procedure is mandatory. Where no SIA is required by the IESO, Hydro One may waive the requirement for a CIA study if the transmitter determines during its preliminary review that the new or modified connection will not materially impact other transmission customers. The transmitter may consult with the IESO prior to waiving the requirement for a CIA study. In cases where the requirement for a CIA study is waived, the transmitter will notify existing customers in the vicinity, advising them of the proposed new connection or modification and of the transmitter's decision not to carry out a CIA on the basis that no material customer impact is expected.

As a guideline, a CIA study may not be required for the following types of connection proposals:

- Like-for-like replacement of existing connection facilities where there is no connectivity change on the transmission system

- Transmission connection facilities where;

  1. no generation is being added;
  2. there is no significant change in system impedance;
  3. the load does not include significant reactive power requirements such as those associated with large motors, furnaces or other similar facilities; and
  4. there is no significant configuration change (e.g. adding in-line breakers, additional breaker diameters), particularly any such changes that may trigger other customers to modify their protections.

- Addition of feeder breakers at system voltages less than 50 kV.

STEPS FOR CONDUCTING A CIA STUDY

The following are typical steps for conducting a CIA study, and are subject to a CIA Agreement.

<u>Step 1: Customer Connection Application & Acknowledgement</u>

- The CIA procedure is initiated through the connection applicant submitting a Connection Application to Hydro One.
- The applicant will submit a Connection Application to Hydro One via Email, Mail, Fax or Courier.
- Hydro One will acknowledge receipt of the Connection Application by Email, Mail, Fax or Courier.

<u>Step 2: Provision of Data and Information for CIA Study</u>

- After confirming receipt of the Connection Application, Hydro One will review the submitted material and request the applicant to provide additional information or clarification of submitted material, if required. This may involve a meeting or conference call with the customer.
- The connection applicant will provide missing information or clarification of submitted information to Hydro One upon request.
- If specific information cannot be provided, Hydro One may propose suitable typical values to be used in the CIA study in this case. It is the responsibility of the connection applicant to ensure that facilities that are later installed have values that are acceptable to Hydro One and the IESO.

<u>Step 3: CIA Agreement</u>

Hydro One and the applicant will execute a CIA Agreement to cover the following:

- CIA study scope including schedule and reporting format.
- Provision of data required to conduct the CIA study.
- CIA study cost, invoicing and payment schedule and method. Hydro One will provide the cost of the study at the time of the CIA Agreement in accordance with the Schedule of

Charges & Fees or based on an estimated cost depending on the complexity of the proposed connection.

- Confidentiality and information sharing including distribution of study results & report to other parties.

Step 4: Customer Impact Assessment Prerequisites

Hydro One's CIA study will be initiated once:

- the customer has executed a CIA Agreement with Hydro One;
- the customer has provided all data required to conduct the CIA study; and
- the IESO has issued its draft System Impact Assessment (SIA) or a draft Expedited System Impact Assessment report.

Step 5: CIA Study and Report

The CIA study will determine the expected impact on the following factors, as appropriate:

- short circuit levels at the customer connection/delivery point,
- supply voltage levels at the customer connection/delivery point,
- adequacy/capacity of supply facilities at the customer connection/delivery point,
- reliability of the supply at the customer connection/delivery point,

Hydro One will use the results of the CIA study to provide all the other transmission customers affected by the proposed new or modified connection with a new available fault current level. This will allow each customer to take action, at its own expense to upgrade its facilities as may be required to accommodate the new available fault current level up to the maximum allowable fault levels as set out in the Code - Appendix 2 - Transmission System Connection Point Performance Standards.

Hydro One will prepare a report outlining the CIA study results. The report will include the relevant information used in the assessment, including Hydro One's and the connection applicant's information.

- Hydro One will issue a draft of the CIA report to the IESO and other affected customers that will outline the impact of the new or modified connection on the supply at the connection facility.
- Hydro One will accept preliminary feedback from the IESO and other affected customers on the draft report.
- Hydro One will issue a final report after the IESO and other affected customers have provided their preliminary feedback.

Hydro One will distribute the CIA report to the Electrical Safety Authority (ESA), the IESO, the connection applicant and other transmission customers in the study area.

Section 2.5

ECONOMIC EVALUATION PROCEDURE

INTRODUCTION

Hydro One's Economic Evaluation Procedure was developed to meet the requirements of section 6.5.2 of the Transmission System Code (the Code). This procedure involves performing a financial evaluation of the relevant costs and revenues for new or modified load connections. The financial evaluation is carried out according to the methodology and inputs prescribed in the Code. To perform the evaluation, Hydro One uses a discounted cash flow model. The model and its assumptions are described below.

HYDRO ONE'S DISCOUNTED CASH FLOW MODEL

Overview

Hydro One uses its discounted cash flow (DCF) model to assess project economic feasibility and determine any contribution-in-aid-of-construction required for new or modified transmission load connections. The model assesses financial impacts of new connection projects on the basis of the relevant revenues and costs. The following revenue and cost elements are included:

- the up-front capital costs for new or modified connection facilities
- on an exception basis, capital costs for new or modified network facilities required to serve the connection as per section 6.3.5 of the Code
- fully allocated overheads on capital and interest during construction (AFUDC) for work performed by Hydro One
- advancement costs only, where Hydro One has planned a new or modified connection facility and moves the planned date forward to accommodate a customer as per section 6.5.2(d) of the Code
- for connection facilities built by a 3rd party and transferred to Hydro One, the transfer price including applicable Hydro One costs and charges
- an estimate of working capital requirements associated with the new or modified connection

Over the economic evaluation period:

- relevant transmission line and/or transformation connection and/or network (on an exception basis per section 6.3.5 of the Code) tariff revenue generated by the new or modified connection
- estimated OM&A costs to operate, maintain and administer the new connection, including property and capital taxes and excluding interest, which is accounted for in the discount rate
- applicable income taxes and income tax shields

A capital contribution will be required from the customer to make up any shortfall between the present value of the costs of the connection facility and the present value of revenues, as indicated by the DCF analysis.

The methodology and assumptions of the DCF model are consistent with the Transmission System Code and specifically the requirements outlined in section 6.5.2 and Appendix 4 –

Customer Financial Risk Classification, and Appendix 5 – Methodology and Assumptions for Economic Evaluations.

Key Assumptions Used in the Model

Economic Evaluation Periods

The economic evaluation periods that are defined in section 6.5.2 (b) and Appendix 4 of the Code are as follows:

- 5 years for high-risk connections
- 10 years for medium-high-risk connections
- 15 years for medium-low-risk connections
- 25 years for low-risk connections

More information about the methodology used to determine the appropriate economic evaluation period is provided below.

Actual or Estimated Capital Costs

The economic evaluation may be calculated initially using estimated costs, provided that subsequently the evaluation is re-calculated based on actual costs. Ordinarily this recalculation will occur within 180 days after the in-service date.

Connection Revenue

Revenue for transmission related connection projects is based on project load information and OEB-approved Line Connection and Transformation Connection tariffs. Revenue is derived from that part of the load customer's new load that exceeds the normal supply capacity of any connection facility already serving that customer, and which will be served by a new or modified connection facility. Any customer's assigned capacity transferred from an existing connection facility already serving the customer will not be credited to the customer's new connection facility revenues. Line connection and transformation connection facilities are subject to separate economic evaluations. Historic revenues and sunk costs are excluded.

Operating, Maintenance and Administrative Costs

OM&A costs are system average estimates for transformation connection and/or line connection facilities as determined and updated by Hydro One.

Incremental Working Cash Requirements

Forecast incremental working cash requirements are estimated based on Hydro One's transmission lead-lag study results applied to project OM&A costs, consistent with an OEB approved working cash methodology.

Allowance for Funds Using During Construction (AFUDC)

Project capital costs include interest during construction (AFUDC) up to the in-service date. The AFUDC rate is the standard interest capitalization rate used for all Hydro One capital projects.

Income Taxes and Net Large Corporation Tax (LCT)

Income taxes, including large corporation tax and applicable surtaxes, and Ontario capital tax, are based on current or future enacted tax rates. Property taxes are based on a transmission system average rate.

After-tax Discount Rate Used for NPV Calculations

The project discount rate is based on Hydro One's prospective capital mix, debt and preference share cost rates, income taxes, and the most recent OEB approved rate of return on common equity.

Timing of Expenditures

Project cash flows are present-valued to the in-service date (time zero). Up-front capital expenditures are treated as occurring at the beginning of the period for discounting purposes. Future capital expenditures, annual connection rate revenues and annual operating and maintenance costs are treated as occurring at the mid-point of the year in which they occur.

Customer Risk Classification

The information below is consistent with Appendix 4 of the Code and is applicable to load connections.

New or Modified Connections that are not Project Financed

For a new or modified connection that is not being financed by the load customer on a "project financing" basis, Hydro One will use a bond rating provided by the customer from a known bond rating agency to determine the risk classification.

Where no bond ratings are available for the customer, Hydro One will use the appropriate Altman Z model (for public industrial companies, private industrial companies, or non-industrial companies), as the case may be, if the necessary information to complete the analysis is available. Hydro One will normally require the customer to provide a copy of its most recent 3 years of audited financial statements in order to do the Altman Z analysis. Where audited financial statements are not available, Hydro One may, at its discretion, use un-audited financial statements or other similar information. If the results of the Altman Z model appear anomalous, Hydro One will use the Kaplan-Urwitz model as a secondary methodology. See below for details on the Altman Z model and the Kaplan-Urwitz model. Also see Appendix 1 at the end of this Procedure for further information.

Where Hydro One considers that the risk classification that results from the application of the above methods produces an anomalous result, Hydro One may, with the customer's consent, assign a different risk classification to the new or proposed connection. Where the customer does not consent, Hydro One may apply to the OEB for approval to determine the customer's risk classification using an alternate methodology.

Where a load customer has not provided Hydro One with some or all of the information necessary to determine the customer's Altman-Z or Kaplan-Urwitz score, Hydro One may use estimates based on comparable information provided by similar customers. Where no such comparable information is available or where Hydro One considers that the customer's circumstances are such as to render comparisons with similar customers inappropriate, Hydro One may classify the risk associated with the proposed new or modified connection as high risk.

Where the new connection is for a project having a finite life (e.g., a new mine with 10 years of proven reserves), the economic evaluation period will be based on the life of the project or the risk rating of the customer, whichever is less.

New or Modified Connections that are Project Financed

For a new or modified connection that is being financed by the load customer on a "project financing" basis, the customer's risk classification will be determined by the type and amount of security provided. Ordinarily a parental guarantee from an entity with an acceptable credit rating will be required. With an acceptable parental guarantee, the risk classification of the project will be based on the risk of the parent, subject to the exception noted above for finite-life projects.

Where acceptable security is not provided, the project will be assigned a high-risk classification.

Risk Horizon Table

Bond ratings or Altman Z scores or Kaplan-Urwitz scores will determine the customer's risk classification according to the tables below.

Risk Horizon Table
Bond Rating and Altman Z Score

Bond Rating*	Altman Z – Score**			Risk Profile	Risk Horizon
	Public Industrial	Private Industrial	Private Non-Industrial		
CCC and below	<1.81	<1.23	<1.10	High Risk	5 Years
B – BB	1.81 – 2.67	1.23 – 2.59	1.10 – 2.32	Medium High Risk	10 Years
Industrial BBB – AAA Non-industrial BBB	2.68 – 2.99	2.60 – 2.90	2.33 – 2.60	Medium Low Risk	15 Years
Non-industrial A - AAA	>2.99	>2.90	>2.60	Low Risk	25 Years

* Based on DBRS rating scale. Investment grade credits qualify for risk ratings of 15 years and above. Non-investment grade credits qualify for risk ratings of less than 15 years. Equivalent ratings from other rating agencies would apply if deemed suitable by Hydro One.

** Public non-industrial companies or other entities that do not fall within the compass of one of the 3 Altman Z models will be assessed using an appropriate methodology, at Hydro One's discretion

Altman Z Public Industrial Model

The Altman Z Score is calculated as:

$$Z = 1.2 * X_1 + 1.4 * X_2 + 3.3 * X_3 + 0.6 * X_4 + 1.0 * X_5$$

Where,

X_1=net working capital/total assets
X_2=retained earning/total assets
X_3=earning before interest and taxes (EBIT)/total assets
X_4=market value of equity/ total liabilities
X_5=sales/total assets

Altman Z Private Industrial Model

The Altman Z Score is calculated as:

$$Z' = 0.717 * X_1 + 0.847 * X_2 + 3.107 * X_3 + 0.420 * X_4 + 0.998 * X_5$$

Where,

X_1=net working capital/total assets
X_2=retained earning/total assets
X_3=earning before interest and taxes (EBIT)/total assets
X_4=book value of shareholders' equity/total liabilities
X_5=sales/total assets

Altman Z Private Non-Industrial Model

The Altman Z Score is calculated as:

$$Z'' = 6.56 * X_1 + 3.26 * X_2 + 6.72 * X_3 + 1.05 * X_4$$

Where,

X_1=net working capital/total assets
X_2=retained earning/total assets
X_3=earning before interest and taxes (EBIT)/total assets
X_4=book value of shareholders' equity/total liabilities

Risk Horizon Table
Bond Rating and Kaplan-Urwitz Score

Bond Rating*	Kaplan-Urwitz Score	Risk Profile	Risk Horizon
CCC and below	<0**	High Risk	5 Years
B – BB	<0**	Medium High Risk	10 Years
Industrial BBB – AAA Non-industrial BBB	> 1.57 1.57 – 3.28	Medium Low Risk	15 Years
Non-industrial A – AAA	> 3.28	Low Risk	25 Years

***** Based on DBRS rating scale. Investment grade credits qualify for risk ratings of 15 years and above. Non-investment grade credits qualify for risk ratings of less than 15 years. Equivalent ratings from other rating agencies would apply if deemed suitable by Hydro One.
** Kaplan-Urwitz bond rating-equivalency scores are not provided for non-investment grade entities (below BBB). Kaplan-Urwitz scores less than zero accordingly will be classified as either high-risk or medium-high risk based on a combination of Kaplan-Urwitz scores, Altman Z scores and other factors such as traditional credit analysis.

Kaplan-Urwitz Model

The Kaplan-Urwitz score is calculated as:

$$KU = 4.41 + 0.0012 * X_1 – 2.56 * X_2 - 2.72 * X_3 + 6.40 * X_4 - 0.53 * X_5 + 0.006 * X6$$

Where,
X_1=total assets ($000)
X_2=subordinated debt (dummy variable, 1 or 0)
X_3=long-term debt/total assets
X_4=net income/total assets
X_5=co-efficient of variation in net income over 5 years*
X_6=interest coverage (EBIT/interest expense)

* Less than 5 years' of financial statement information will be used when the information is not available.

True-Up Procedure for Load Customers

For new or modified load connection facilities, Hydro One will carry out a true-up calculation, based on actual customer load, at the following true-up points as per sections 6.5.3 to 6.5.11 of the Code:

(a) for high risk connections, at the end of each year of operation, for five years;
(b) for medium-high risk and medium-low risk connections, at the end of each of the third, fifth and tenth year of operation; and
(c) for low risk connections, at the end of each of the fifth and tenth year of operation, and at the end of the fifteenth year of operation if actual load is 20% higher or lower than the initial load forecast at the end of the tenth year of operation.

For the true-up calculation, Hydro One shall use the same methodology used to carry out the initial economic evaluation, and the same inputs except for load, which will be based on the actual load up to the true-up point and an updated load forecast for the remainder of the economic evaluation period used.

Before carrying out a true-up calculation for a load customer who did not make an initial capital contribution, Hydro One shall adjust the initial load forecast used in the initial economic evaluation to the point where the present value of connection rate revenues equals the present value of costs as per section 6.5.5 of the Code.

Where a true-up calculation shows that a load customer's actual load and updated load forecast is lower than the load in the initial load forecast, and does not generate the initial forecast connection rate revenues, Hydro One shall require the load customer to make a payment to make up the shortfall, adjusted appropriately to reflect the time value of money and net of any previous true-up payments made.

Where analysis shows that the customer has transferred assigned capacity from an existing Hydro One owned connection facility already serving the customer to the new connection facility, which is the subject of the economic evaluation, the customer's actual load for true-up purposes will be reduced in proportion to the amount transferred. The updated load forecast will also be reduced to eliminate any transferred load. If there is a shortfall, Hydro One will then require the customer to remit a payment to make up the shortfall, adjusted appropriately to reflect the time value of money and net of any previous true-up payments made.

Where a true-up calculation shows that a load customer's actual load and updated load forecast is higher than the load in the initial load forecast, and generates more than the initial forecast connection rate revenues, Hydro One will post the excess revenue as a credit to the customer in a notional account, net of any previous true-up credits. Hydro One will apply the net credit against any shortfall in subsequent true-up calculations. Hydro One will rebate to the load customer any credit balance that remains when the last true-up calculation is carried out, adjusted appropriately to reflect the time value of money and applicable income and other tax impacts. The rebate shall not exceed any capital contribution, adjusted to reflect the time value of money, previously paid by the load customer.

When carrying out a true-up calculation for a distributor, Hydro One:

(a) shall add to the actual load the amount of any embedded generation (determined in accordance with section 11.1 of the Code) that was installed during the true-up period; and
(b) shall not reduce the updated load forecast as a result of any embedded generation (determined in accordance with section 11.1 of the Code) that was installed during the true-up period.

When carrying out a true-up calculation for a load customer other than a distributor, Hydro One:

(c) shall add to the actual load the amount of any embedded generation (determined in accordance with section 11.1 of the Code) of 1 MW or less per unit, or any embedded renewable generation of 2 MW or less per unit, that was installed during the true-up period; and

(d) shall not reduce the updated load forecast as a result of any embedded generation (determined in accordance with section 11.1 of the Code) of 1 MW or less per unit, or any embedded renewable generation of 2 MW or less per unit, that was installed during the true-up period.

When carrying out a true-up calculation for any load customer, Hydro One:

(e) shall add to the actual load the amount of any reduction in the customer's load that the customer has demonstrated to the reasonable satisfaction of Hydro One (such as by means of an energy study or audit or annual or quarterly reports from an OEB approved CDM program) has resulted from energy conservation, energy efficiency, load management or renewable energy activities that occurred during the true-up period; and
(f) shall not reduce the updated load forecast as a result of any reduction in the customer's load that the customer has demonstrated to the reasonable satisfaction of Hydro One (such as by means of an energy study or audit or annual or quarterly reports from an OEB approved CDM program) has resulted from energy conservation, energy efficiency, load management or renewable energy activities that occurred during the true-up period.

Where a load customer voluntarily and permanently disconnects its facilities from a transmitter's facilities prior to the last true-up point, Hydro One shall, at the time of disconnection, carry out a final true-up calculation in accordance with the rules set out above. Where the true-up calculation shows that the load customer's load to the date of disconnection has not generated the initial forecast connection rate revenues, the transmitter shall require the load customer to make a payment to make up the shortfall, adjusted appropriately to reflect the time value of money and net of any previous true-up payments. Where a true-up calculation shows that the load customer's load to the date of disconnection has generated more than the initial forecast connection rate revenues, Hydro One shall rebate to the load customer any excess, adjusted appropriately to reflect the time value of money and applicable income and other tax impacts.

Transfer Price

Where Hydro One pays a transfer price for a connection facility constructed by a load customer, Hydro One will reflect the transfer price plus applicable charges and costs in the capital contribution that is to be paid by the customer. The amount to be reflected in the capital contribution is determined as follows:

Capital cost* = Transfer price + Hydro One project-specific costs +

(a) make-ready costs on transferred assets including inspection, testing, commissioning and any other costs of incorporation +
(b) capital costs of any Hydro One Uncontestable Work +
(c) full direct and indirect capitalized overheads on capital costs in (a)+(b).

** The above is a general definition only. Capital and operating costs for individual projects will be based on the estimated costs of those projects. Some of the cost elements listed above could be capital or operating costs, and not all cost elements may be applicable for each project.*

APPENDIX I

Further information regarding the Altman Z and Kaplan-Urwitz models, per Hydro One's response to OEB Staff Interrogatory #20 in EB-2006-0189

Ontario Energy Board (Board Staff) INTERROGATORY #20

Interrogatory

Ref.(a) H1N-CCP/ Section 2.5 Economic Evaluation/ Load Connection Applicant Without Bond Rating/ pp.33 – 35
Ref.(b) SC/Appendix 4
Ref.(c) TSC/Appendix 4/ "Report" to the Board dated March 30, 2000 referenced in Appendix 4, authored by PHB Hagler Bailly and entitled "Risk Assessment Methodology Options". The report is available from the Board's website at www.oeb.gov.on.ca.

Preamble

- The directions to the transmitter are spelled out in In Ref. (b)- Appendix 4 of the TSC, as well as in Ref.(c), covering various aspects including use of two financial Models (the Altman Z-score Model and the Kaplan-Urwitz Model) for evaluating financial risks of companies, where no bond ratings are available. The use of the two models requires certain information be available to the transmitter.

- In Ref. (b) the Board indicated that a revision to the transmitter's economic evaluation procedure to update a Model shall not constitute a material amendment to the transmitter's connection procedures for the purposes of section 6.1.5 and therefore does not require the approval of the Board.

- However, this is the first opportunity for the Board to review and compare the details of the two models (Altman Z-score and the Kaplan-Urwitz Model) outlined in Ref. (a) with the corresponding Models in the original Report [Ref.(c)]. Therefore responses to various clarifications and questions listed below are needed.

Questions/Clarification

In Ref. (a), page 34, Hydro One added two new Altman Z –score Models in addition to the Model listed in the "Report" [Ref.(c)]; the first new Model is for "Public Industrial Companies" and the second new Model is for "Private Non-Industrial Companies".

Re: Altman Z-score Model

(i) Please provide the name of the entity that publishes the Altman Z-score Models, its address and a contact person's telephone and e-mail address;

(ii) when were the two new Models developed? and how often the three Models are updated [the original listed in Ref.(C) and the two new ones in Ref. (a)]?

(iii) The two bullets below compare the two tables in the two indicated references:
  - In page 4 of Ref.(c), the table depicts three levels of "Projected Credit Risk", and the corresponding Altman Z-score which corresponds to the "Private Industrial" Model as follows:

If Altman Z-Score is:	Projected Credit Risk is
< 1.2	High
1.2-1.9	Meduim
>2.9	Low

- In page 33 of Ref. (a), The corresponding Table for the Altman Z-score covering three types of industrial companies as follows:

Bond Rating*	**Altman Z – Score****			**Risk Profile**	**Risk Horizon**
	Public Industrial	**Private Industrial**	**Private Non-Industrial**		
CCC and below	<1.81	<1.23	<1.10	High Risk	5 Years
B – BB	1.81 – 2.67	1.23 – 2.59	1.10 – 2.32	Medium High Risk	10 Years
Industrial BBB – AAA Non-industrial BBB	2.68 – 2.99	2.60 – 2.90	2.33 – 2.60	Medium Low Risk	15 Years
Non-industrial A – AAA	>2.99	>2.90	>2.60	Low Risk	25 Years

With regard to the two above tables:

(a) Please provide full explanation and justification on how the score range of (1.2 – 2.9) of the Altman Z-score corresponding to "Medium Risk" of Ref. (c), was apportioned in Ref.(a) between "Medium High Risk" with Z-score range =1.23 – 2.59, and "Medium Low Risk" with Z-score range= 2.6 – 2.9.

Note: that the mid point on linear basis between the two ranges, would lead to a range in the Z-score of 1.23 – 2.1 for "Medium High Risk" and 2.2 – 2.59, for "Medium Low Risk"

(b) Please provide details and justification for selection of the ranges depicted for the Altman Z-score vis a vis the four risk categories (High, Medium High, Medium Low, and Low) for the two new Models corresponding to the Models for Public Industrial Companies and for the Private Non-industrial companies.

Re: Kaplan-Urwitz Model

(iv) The Model proposed for the Kaplan-Urwitz model in page 35 of Ref.(a), is identical to the Kaplan-Urwitz Model shown in page 6 of Ref.(c) except for the use of an additional term (- 2.56 * X_2) where X_2 is a "dummy" or "categorization" variable which is assigned a value X_2 = 1 if the debt is subordinated, and a value of X_2 = 0 if the debt is not subordinated.

(a) Please indicate whether this term (– 2.56 * X_2) is the original term in the Model which according to Ref. (c)/ page 6/ foot note 3, was published in April, 1979;

(b) Please indicate whether this Model is revised by the authors, or by any other entity in the financial industry? if so, please indicate by who and when was the last time it was revised;

(c) Please provide explanation and justification for the range chosen for the Kaplan-Urwitz score for the "Industrial" class where it appears that regardless of how high a company can score, it cannot exceed "Meduim Low Risk".

Response

(i,ii) Hydro One is not aware of an official entity that publishes the Altman Z models. The financial literature contains numerous references to versions of the Altman Z model. The 3 versions that were included in the company's filed procedures were obtained from a 1995 CPA Journal extract found on the web, "Z scores – a guide to failure prediction" by Gregory J. Eidleman. The CPA Journal is a refereed publication published by the New York State CPA Society. This article appeared to be the most concise source of information regarding the 3 Altman Z models.

Hydro One also reviewed other sources including an article by Prof. Edward Altman, the Z-model's developer ("Predicting the Financial Distress of Companies: Revisiting the Z-score and Zeta models", July 2000) also found on the web. This article provided background on the development of the 3 models and their strengths and weaknesses. As the article discusses, the first Altman Z model was developed in the late 1960's based on a sample of public manufacturing company data (the "public industrial" model included in Hydro One's filing). That model was later adapted by Altman (the article does not indicate when) for private manufacturing companies (the "private industrial" model included in Hydro One's filing). This is the model that was included in the PHB Hagler Bailly report (reference (C) of Staff's interrogatory). The final adaptation by Altman was to extend the model for use with respect to non-manufacturing companies (the "private non-industrial" model included in Hydro One's filing). This latter model is also cited occasionally in the literature as the "generalized" model and appears to be considered by some as applicable across industry-types.

Hydro One is not aware how often (if at all) the various versions of the Altman Z model are updated. Hydro One included all of the models in its connection procedure in order to provide as wide a basis as possible for assessing new connections and allow for a matching of the appropriate model with a given set of circumstances.

(iii)

(a) The PHB Hagler-Bailly report (ref. C) provided a breakdown of Altman Z-scores into 3 categories (High, Medium, Low). In order to provide a 4-category breakdown consistent with the risk-classifications established by the Board (High, Medium-high, Medium-low, Low), transmitters were required to split PHB's "medium" category into 2 sub-categories. As noted above, the version of the Altman Z model provided in the PHB report was the private manufacturing model (using Prof. Altman's terminology), and this is the version referenced in Staff's Interrogatory above. Intermediate cut-off points between the high and low values that allowed for splitting the "medium" risk category into 2 sub-categories were not available in the literature for this model, nor for the private non-industrial model. Intermediate cut-offs were, however, provided by Prof. Altman in the article referenced above for the public industrial model. The splitting of the medium category for the private industrial and private non-industrial models in Hydro One's filing was accordingly based on scaling their intermediate cut-off points using the corresponding scale from the public industrial model. The formula for the private industrial model intermediate cut-off point is as follows:

$2.59 = 2.90 \times 2.67 / 2.99$

The formula for the private non-industrial intermediate cut-off point is:

$2.32 = 2.6 \times 2.67 / 2.99$

(b) The high and low values for the two "new" Altman-Z models (Public Industrial and Private Non-industrial) included in Hydro One's connection procedure were taken from the CPA Journal article referenced above. See part (a) above for an explanation of the derivation of their intermediate cut-off points.

(iv)

(a) Hydro One is not aware whether the subordinated-debt term referenced in footnote 3 of the PHB report was included in the original Kaplan-Urwitz model; the footnote in the PHB report indicates that it was included in the "formal" model. Hydro One included the subordinated-debt term in the model filed in its connection procedure in order to provide a version of the model able to accommodate situations in which subordinated debt was present.

(b) Hydro One is not aware whether the Kaplan-Urwitz model is or has been revised by the authors or by any other entity. A web search did not provide any information in this regard.

(c) The industrial category in the Kaplan-Urwitz model is treated in a manner consistent with the methodology used for industrials in the Altman Z model and bond ratings (i.e., industrial customers are eligible for a maximum 15-year risk horizon under all approaches). This is due to the inherent riskiness of industrial companies. The 15-year maximum reflects 2 key concerns:

- Intense competition in industrial markets due to the impact of globalization, currency swings and commodity price fluctuations, among other factors. These factors expose industrial companies in particular to quickening rates of change and hence higher risk.

- The lack of liquidity in a transmission investment compared with a financial instrument such as a bond. Bond ratings are based partly on the liquidity of the instrument being rated. Accordingly, a bond rating is not a perfect tool to use in measuring the long-term risks to the transmission pool arising from an illiquid new connection. This suggests that some element of judgment is in order when using bond ratings for risk assessment purposes with respect to transmission investments.

Recognizing these concerns (increasing rates of change affecting industrial companies in particular, and the imprecise nature of bond ratings as a risk assessment tool), a 15-year maximum risk horizon for industrial companies is considered prudent in managing the risks to the transmission pool.

Section 2.6

CONTESTABILITY PROCEDURE

INTRODUCTION

Hydro One's Contestability Procedure has been developed to meet the requirements of section 6.6.2 of the Transmission System Code (the Code). The Contestability Procedure allows Hydro One to identify to connection applicants the estimated cost of the transmission assets required to facilitate the proposed connection and to identify which transmission connection assets are contestable and can be built by the connection applicant. The customer can then elect one of three options regarding the construction and ownership of the new connection facilities:

1) The connection applicant can elect to have Hydro One construct and own all new connection facilities.
2) The connection applicant can elect to construct all of the new connection facilities identified as contestable work and transfer ownership of specific elements to Hydro One. (Transfer of non-dedicated contestable connection facilities is a requirement, not an option.)
3) If the new connection facilities are dedicated connection facilities, the connection applicant can elect to construct and own the new facilities.

Data provided by Hydro One and the connecting customer, together with the specific construction and ownership options elected by the connecting customer, form the basis for a Connection and Cost Recovery Agreement (CCRA) to be made between the two parties.

Glossary

Contestable Work

New connection facilities that are for the sole benefit of the connecting customer(s) that do not involve:

(a) The modification of or expansion of the transmitter's existing assets, or,
(b) The utilization of an existing station site or an existing right-of-way over which the transmitter has ownership, easement or other land rights.

The transmitter may permit the connecting customer to terminate their lines at Hydro One's assets.

Dedicated Connection Facilities

Transmission connection facilities devoted to serving a single Customer.

Detailed Estimate

Based on the completion of additional design work at the connecting customer's expense, this is an estimate prepared by Hydro One based on the specific costs included in a project and for the labour required to design, construct and manage the project. Such an estimate is summarized into the following basic groupings: Engineering, Construction, Materials, Commissioning, Project Management, Risk/Contingencies, Interest and Overheads. Estimate accuracy is usually plus or minus 10% and it will typically take 90 days to prepare. The detailed estimate and any other estimates other than the Initial Estimate is at the customer's cost.

Initial Estimate

The Initial Estimate is the preliminary capital cost estimate prepared by Hydro One derived from the assembly of components and actual costs from previous projects that is provided to a connection applicant at Hydro One's expense. It does not include detailed costs of items but comprises estimated costs for major components and areas of work. Costs will be summarized in the following areas: Engineering, Construction, Materials, Commissioning, Project Management, Risk/Contingencies, Interest and Overheads. Estimate accuracy is usually plus or minus 20% and it will typically take 45 days to prepare.

Non-Dedicated Connection Facilities

Connection facilities supplying more than one customer (load customer or generator customer).

Sole Benefit

Connection facilities that are required now and in the foreseeable future strictly for the connection of the connecting customer(s).

Transmitter's Reasonable Cost

The most accurate estimate available of the cost for the transmitter to construct the contestable work. It is the initial estimate value if agreed by both parties or the detailed estimate if one was prepared by Hydro One. Costs incurred to create a detailed estimate are recoverable from the connecting customer.

Uncontestable Work

All connection facilities that are not for the sole benefit of the connecting customer and all additions, modifications and physical connection work which involves:

(a) The modification or expansion of Hydro One's existing assets; or,
(b) The utilization of an existing station site or an existing right-of-way over which Hydro One has ownership or easement or other land rights.

CONTESTABILITY PROCEDURE

Connecting Customer Requires a New Connection Facility

The Contestability Procedure is initiated when a connection applicant has submitted a formal Connection Application to Hydro One and the Customer Impact Assessment, if required, has been completed.

Hydro One Provides the Preliminary Estimate and Supporting Information

Hydro One provides the connecting customer with the following required information, at no cost:

(a) A description of the contestable work and the uncontestable work;
(b) A description of the labour and materials required for each of the contestable work and the uncontestable work;
(c) An initial estimate of the capital cost of each of the contestable work and the uncontestable work based on Hydro One's design, construction, operation & maintenance standards, together with an indication of the degree of accuracy of the estimate;
(d) The calculation used to determine any capital contribution to be paid by the connecting customer if Hydro One constructs the connection facilities, even if no capital contribution is required;
(e) The information set out in Appendix 3 of the Code and enough information in sufficient detail to allow the connecting customer to design and construct connection facilities that will meet the transmitter's system requirements. Hydro One's connection requirements will have to be met if the connecting customer is to ultimately own and operate the facility; and,
(f) Hydro One's design, construction, operation and maintenance standards applicable to the contestable work to allow the connecting customer to proceed with detailed engineering. These requirements will have to be met if the connecting customer is to build the facilities and transfer them back to Hydro One to maintain and operate.

Hydro One will provide revisions to the above information at the connecting customer's expense, if the customer requires additional information as a result of changes to the customer's plans or wishes to obtain additional design work in order to enhance Hydro One's initial estimate.

Connection Facility Ownership Decision

Where a connecting customer requires new connection facilities and those facilities are identified by Hydro One as contestable, the customer can elect either to construct its own connection facilities or to require Hydro One to construct them. The customer must also determine if the new connection facilities will be customer-owned or owned by Hydro One as a transmission connection asset.

If the connection facility includes uncontestable work, that portion of the work can only be constructed and owned by Hydro One. The customer cannot construct or own such a connection facility. Where the connection facility includes contestable work, the connecting customer does have the right to either provide this part of the connection facility itself or to require Hydro One to provide it. Where the customer chooses to carry out the contestable work, it must carry out all of the contestable work.

At this stage, the connecting customer must also decide whether it will transfer dedicated connection facilities that it builds to Hydro One following successful construction and commissioning.
If the customer elects to have Hydro One build the connection facilities, proceed to Option 1 below.

If the customer elects to build the connection facilities to transfer to Hydro One, proceed to Option 2. (The customer may choose to transfer all or part of the contestable work.)
If the connection facility will be customer built and owned, proceed to Option 3.

Option 1: Hydro One Builds and Owns the Connection Facility

The parties will enter into a Connection and Cost Recovery Agreement (CCRA) describing the terms and conditions relating to the project scope and cost responsibilities. Once signed, this agreement will be binding and Hydro One will undertake the work and own the connection facility. A capital contribution may be required to the extent that the cost of the connection facility is not recoverable in connection rate revenues. (See section 6.5.2 of the Code and Hydro One's Economic Evaluation Procedure).

Hydro One undertakes the work including the design, construction, testing, inspection and commissioning of the connection facility. Upon completion of the connection facility, Hydro One recalculates the capital contribution requirement based on Hydro One's actual cost of construction including direct and indirect capitalized overheads.

Following completion of these steps, the Contestability Procedure ends.

Option 2: Customer Builds Connection Facility to Transfer to Hydro One

The parties will enter into a CCRA which includes terms and conditions applicable to the contestable work. Once the CCRA is executed by both parties, the CCRA will be binding and Hydro One will own the connecting facility when built by the customer in accordance with the terms of the CCRA and after it is transferred to Hydro One. The CCRA will describe the terms and conditions with respect to any work that Hydro One is performing related to the connection facility and any work that Hydro One performs on its transmission system to accommodate the connection of the facility as well as the terms and conditions necessary for Hydro One to take ownership. A capital contribution may be required to the extent that the cost of the connection facility transferred to Hydro One is not recoverable in connection rate revenues. (See section 6.5.2 of the Code and Hydro One's Economic Evaluation Procedure).

Where a connecting customer proposes to, or is obliged to, transfer any connection facilities it constructs to Hydro One, Hydro One will provide, upon request and at cost as per section 6.6.2 (f) of the Code, a detailed design to allow the customer to carry out the contestable work and provide Hydro One's Design, Construction, Operation and Maintenance Standards that must be met in constructing the connection facility.

The connecting customer will undertake all inspection, testing and commissioning activities. Hydro One shall have the right to participate in all or any part of the inspection, commissioning, testing and witnessing at the customer's expense as per section 4.3.3 and section 6.6.2 (d) of the Code. The customer must submit a commissioning program in writing to Hydro One 30 business days prior to the planned commissioning tests. Hydro One must indicate to the customer within 15 business days of receiving the program if it agrees with the proposed commissioning program and test procedures or if it requires changes in the interest of safety or maintaining the reliability of the transmission system as outlined in Appendix 1, Schedule E, Section 1.7 of the Code. The connecting customer will transfer the connection facility to Hydro One after construction and commissioning are complete and the customer is in compliance with the CCRA.

Hydro One will pay the customer a transfer price that is the lower of the actual cost to the connecting customer or Hydro One's reasonable cost to do the same work, including direct and indirect capitalized overheads, as per section 6.6.2 (g) of the Code. Hydro One will recalculate the capital contribution requirement based on the capital cost as described below, and update the CCRA accordingly.

The capital cost* is calculated as the sum of the Transfer price + Hydro One project-specific costs +

a) make-ready costs on transferred assets including inspection, testing, commissioning and any other costs of incorporation +
b) capital costs of any Hydro One Uncontestable Work +
c) full direct and indirect capitalized overheads on capital costs in (a)+(b).

* *The above is a general definition only. Capital and operating costs for individual projects will be based on the estimated costs of those projects. Some of the cost elements listed above could be capital or operating costs, and not all cost elements may be applicable for each project.*

Following completion of these steps the Contestability Procedure ends.

<u>Option 3: Customer Builds and Owns the Connection Facility</u>

When the customer decides to design, build, own and maintain its own connection facility, the connection facility is to be designed and built in accordance with Hydro One's system requirements. The parties will enter into a CCRA describing the terms and conditions relating to the project scope and cost responsibilities. Once signed, this agreement will be binding and the connecting customer will undertake the work and own the connection facility.

Hydro One, as the transmitter, shall have the right to participate, at the connecting customer’s expense, in the witnessing, commissioning, inspecting or testing of the customer-owned facility as these facilities can have an impact on Hydro One’s transmission system as per section 4.3.3 and Section 6.6.2 (d) of the Code.

Following completion of these steps the Contestability Procedure ends.

Section 2.7

RECONNECTION PROCEDURE

INTRODUCTION

Hydro One's Reconnection Procedure has been developed to meet the requirements of section 6.10.3 of the Transmission System Code (the Code). The Reconnection Procedure applies following voluntary and involuntary disconnection (excluding planned and unplanned outages).

PROCESS STEPS

Transmission customers are required to follow the reconnection procedure when they request to be reconnected following a voluntary or involuntary disconnection. Any cost incurred by Hydro One including Customer Impact Assessment (CIA) studies or system assessment studies are to be borne by the customer.

Step 1:

The customer will complete an Application for Reconnection to initiate the reconnection process providing the reason for disconnection and any measures taken to rectify any connection issues if required.

Step 2:

Customer submits the application to Hydro One and the IESO.

Step 3:

Hydro One will review the reason for disconnection of the customer's facilities and any actions taken. Hydro One will provide the customer with the results of the review and shall request any additional information required by Hydro One to assess the changes made at the customer site.

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Step 4:

The customer will provide any additional information required by Hydro One to assess the changes made at the customer site.

Step 5:

The IESO will identify any reconnection requirements it deems necessary and provide a copy to Hydro One and the customer.

Step 6:

Hydro One will determine if a CIA study is required due to any changes at the customer's site or Hydro One's facilities. A CIA study will only be required if it is deemed necessary to ensure system integrity or if a System Impact Assessment (SIA) is required by the IESO. If a CIA study is needed the customer will be required to enter into a Study Agreement with Hydro One.

Step 7:

If a CIA study is not required, Hydro One will direct the customer to the Equipment Compliance Process if applicable.

Step 8:

Once Hydro One is satisfied that reconnection of the customer's facilities will not cause any adverse effects on the transmission system, the customer will be advised in writing when reconnection can take place. Hydro One shall have the right to participate in all or any part of inspection, testing and commissioning activities that may be required by Hydro One, at the customer's cost.

Section 2.8

DISPUTE RESOLUTION PROCEDURE

INTRODUCTION

Hydro One's Dispute Resolution Procedure has been developed to meet the requirements of section 12.1.1 of the Transmission System Code (the Code). Hydro One is required to implement the dispute resolution procedure in the event of a dispute with a customer regarding Hydro One's obligations under the *Electricity Act*, the Code or Hydro One's transmission licence. This procedure includes provisions that:

a) provide for fair, timely and effective resolution of disputes;
b) set out specific steps for completion of the Dispute Resolution Procedure; and
c) establish the right of Hydro One or the customer to bring a dispute to the OEB for resolution, if it has not been resolved by the parties within 30 days.

EXCEPTIONS

This Dispute Resolution Procedure shall not apply to disputes that arise between a transmitter and a customer that are:

a) governed by the Dispute Resolution Procedure contained in their Connection Agreement, or
b) related to the terms and conditions of a contractual arrangement that is under negotiation between Hydro One and the Customer, except where one party alleges that the other party is:

    - seeking to impose a term or condition that is inconsistent with or contrary to the OEB Act, the Electricity Act, a party's license, the Code or any of Hydro One's connection procedures.
    - refusing to include a term or condition that is required to give effect to the Code or any of Hydro One's connection procedures.

NOTIFICATION OF DISPUTE

A customer or Hydro One can notify the other party of a formal complaint by completing the Customer Dispute Notification form available on Hydro One's website. Hydro One will log the date the complaint is received/initiated and track the progress of the dispute to resolution. Hydro One will appoint a representative to give the customer a single point of contact within the company.

ACKNOWLEDGEMENT OF DISPUTE

Hydro One shall confirm receipt of the Customer Dispute Notification form within 3 business days. An acknowledgement letter will provide the name and contact information of the Hydro One representative and request a meeting to review the background information related to the dispute.

DISCOVERY OF FACTS

Hydro One's representative will meet with the customer in person or by teleconference within 10 calendar days of receipt of the Customer Dispute Notification form, or within a time mutually agreeable to both parties to:

a) review the issues and information related to the customer's position in relation to the Dispute.
b) discuss applicable legislation, licence provisions, the Code and Hydro One's OEB approved connection procedures related to the Dispute.
c) determine if the Dispute may be settled informally at this stage to the mutual satisfaction of both parties.

The Hydro One representative will document the customer's position and the customer's supporting information in the form of Minutes of Meeting to be completed within 2 business days of the meeting. The Hydro One representative will obtain concurrence on the contents of the Minutes from the customer and agreement on a date on which it will provide a formal offer to settle the dispute. Hydro One will prepare a formal offer to settle and forward it to the customer in accordance with the timeline agreed by the parties.

If the parties agree on terms of a formal settlement at the meeting, Hydro One will prepare a Settlement Agreement for the customer to review and both parties to sign.

NEGOTIATE SETTLEMENT

If the customer accepts Hydro One's offer to settle, Hydro One will prepare a Settlement Agreement for the customer to review and both parties to sign.

If the customer rejects Hydro One's offer to settle, the customer or Hydro One may request a meeting or teleconference to review the offer and each others position to determine if a settlement is possible.

If the Customer and Hydro One cannot reach a settlement at this point, the parties may choose to:

(a) jointly suspend negotiations for a mutually agreeable time to review their respective positions.
(b) jointly agree to follow the Dispute Resolution Procedure contained within Section 17 of the Transmission Connection Agreement (TCA) applicable to the parties. In accordance with sections 17.5.7 and 17.5.12 of the TCA, a copy of the decision of the arbitrator(s) and minutes

setting out the terms of settlement, from which all Confidential Information (as defined in the TCA) has been expunged, will be made available to the public by Hydro One.

(c) jointly or individually bring the dispute to the OEB for resolution.

SIGN-OFF SETTLEMENT

Where a customer has accepted Hydro One's offer to settle or the two parties have agreed on an alternate settlement, Hydro One will prepare a Settlement Agreement for the customer to review and both parties to sign. The Settlement Agreement is to be executed by the parties within 7 business days of reaching the Settlement or within a timeframe mutually agreed to by the parties.

FAILURE TO HONOUR SETTLEMENT AGREEMENT

Where a party fails to comply with the terms of the Settlement Agreement, the other party shall have the right to:

1) exercise any right that it may have in the Settlement Agreement
2) exercise any right in law, or
3) have the right to take the matter to the OEB for resolution

Notwithstanding the foregoing, neither party may take the matter to the OEB where the parties have jointly agreed to follow the Dispute Resolution Procedure contained within Section 17 of the TCA applicable to the parties. Section 17.5.11 of the TCA specifies that where a party fails to comply with the terms of a settlement agreement reached during the course of arbitration, the other party may submit the matter to arbitration if the settlement has not been recorded in the form of an award under the *Arbitration Act, 1991*.

SUMMARY OF DISPUTE

Hydro One will prepare a summary of the dispute and related issues. Documentation related to the dispute will be retained by Hydro One and filed with the executed copy of the Settlement Agreement. If requested by the Board, Hydro one will file the records relating to the resolution of the dispute. Where warranted, those records may be filed with a request that they be held in confidence in accordance with the Board's "Practice Direction on Confidential Filings."

3.0 TRANSMISSION PLANS

Hydro One develops and refines plans on an ongoing basis to address load growth and maintain the reliability and integrity of its transmission system. Upon request from a customer, Hydro One will provide the customer with the relevant and most recent version of such plans that cover the applicable portions of its transmission system.

The general rule is that a transmission customer must pay for new or modified transmission connection facilities that are intended to provide benefit to that customer. A capital contribution towards those connection facilities may be required to the extent that the costs associated with those facilities are not recoverable in connection rate revenues.

However, section 6.3.6 of the Transmission System Code provides the following exception to the above cost responsibility rule: “The transmitter shall not require a customer to make a capital contribution for a connection facility that was otherwise planned by the transmitter, except for advancement costs.” Therefore, a customer is not required to make a capital contribution in situations where the new or modified connection facilities were otherwise planned by Hydro One, substantially independent of the customer, to address system needs, except for advancement costs.

4.0 SCHEDULE OF CHARGES & FEES

HYDRO ONE CUSTOMER CONNECTION PROCESS
SCHEDULE OF CHARGES & FEES
FOR TRANSMISSION CUSTOMERS

ACTIVITY	COST
Inspection, Testing and Commissioning Activities	Actual Costs
Engineering and Design Activities	Actual Costs

STUDIES	COST PER STUDY
Standard Customer Impact Assessment (CIA) Study	$15,000
Complex CIA Study	Actual Costs
Detailed Connection Estimate Studies	Actual Costs
Feasibility Studies	Actual Costs
Preliminary Engineering Agreement (PEA)	Actual Costs
Pre-CCRA Letter Agreement for Purchase of Long Lead Items	Actual Costs

In all cases the customer will enter into a Study Agreement with Hydro One.

For Standard CIA studies the scope of activities includes data acquisition and confirmation, load flow modeling & studies, short circuit modeling & studies, customer consultation and report preparation as outlined in the Study Agreement.

For CIA studies that are deemed “complex” by Hydro One and are undertaken for larger or more complex generator and load customer connections, the scope of work, deliverables, expected timelines and payment schedule will be determined on a case-by-case basis and specified in the Study Agreement.

For Detailed Connection Estimate Studies and Feasibility Studies, the scope of work, deliverables, expected timelines and payment schedule will be determined on a case-by-case basis and specified in the Study Agreement.

5.0 TIMELINES FOR CONNECTION PROCESS

Hydro One Customer Connection Process Timelines

	Timeline "On Best Efforts Basis"	**Trigger**
Phase 1 - Connection Application	1-2 months	From initial contact to date of completed Customer Joint (SIA/CIA) Application Form
Phase 2 – Customer Impact Assessment (CIA) [1]	3-5 months	From Date of IESO Issuing Draft System Impact Assessment (SIA)
Phase 3 – Connection Estimates	4-8 months	From Date Estimate Agreement Executed
Phase 4 – Connection Approval	1 month or longer if regulatory approvals, expropriation and permits are required	From Date of Issuing Draft Connection Cost Recovery Agreement (CCRA) for Customer Signature
Phase 5 – Design & Build	Project Specific (normally 12 to 24 months) To be negotiated with customers as per CCRA terms.	Execution of CCRA
Phase 6 - Commissioning	1-2 months	Signing of Connection Agreement [2]

Notes:

1. For renewable generators, the timeline for combined SIA/CIA process is 150 days (5months) from the completion of the application as per OREG 326/09
2. Customer must submit a commissioning plan to Hydro One 30 days before proposed commissioning tests.

SUMMARY OF TRANSMISSION CONNECTION PROCEDURES CHANGES

The following summary highlights the changes that have been made to Hydro One's Transmission Connection Procedures. The changes have been made on pages 3, 22, 27, 57 and 58 in the attached document. The changes are highlighted below.

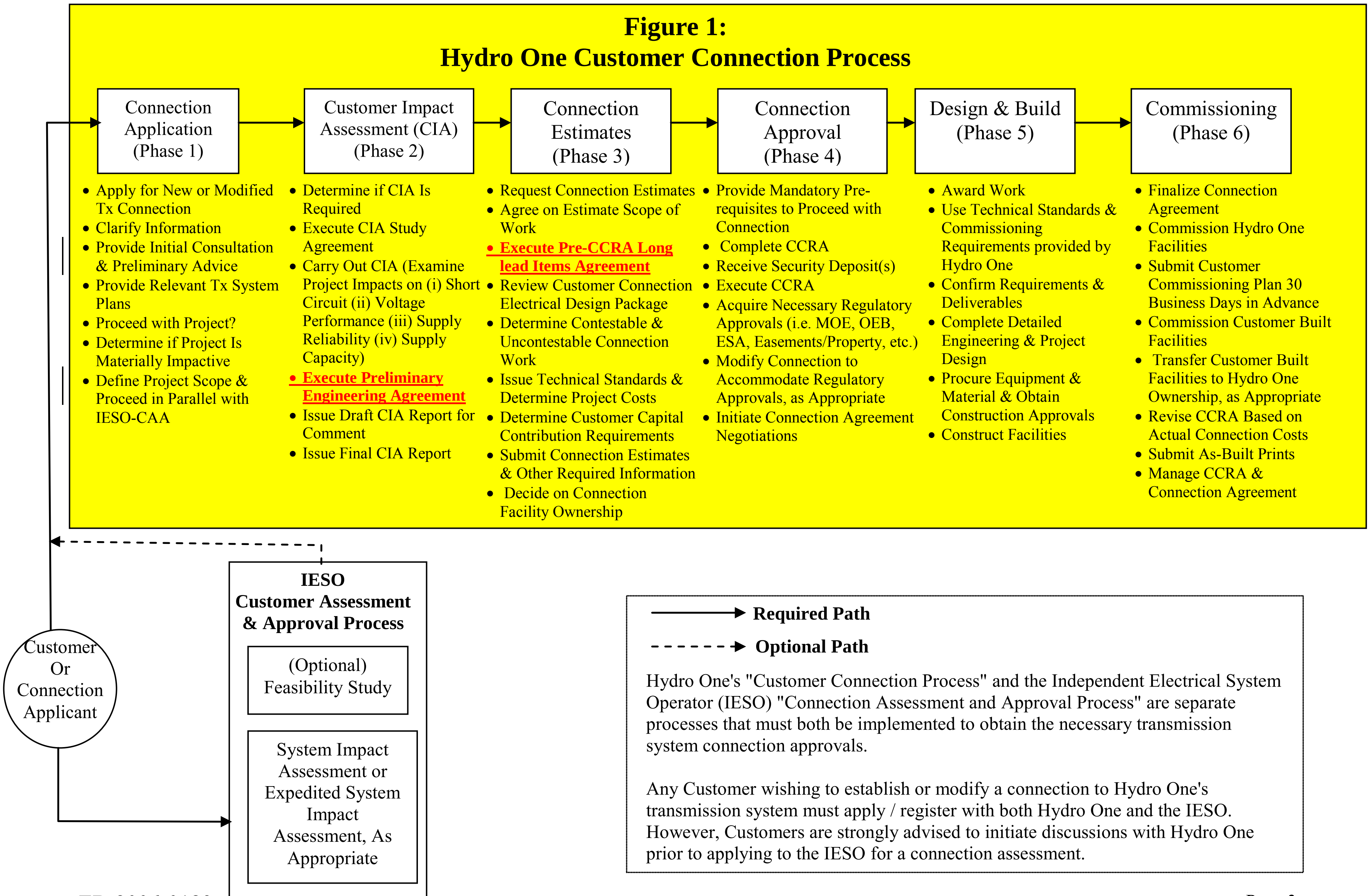

Figure 1:
Hydro One Customer Connection Process
Connection Application (Phase 1)
Customer Impact Assessment (CIA) (Phase 2)
Connection Estimates (Phase 3)
Connection Approval (Phase 4)
Design & Build (Phase 5)
Commissioning (Phase 6)
• Apply for New or Modified Tx Connection
• Clarify Information
• Provide Initial Consultation & Preliminary Advice
• Provide Relevant Tx System Plans
• Proceed with Project?
• Determine if Project Is Materially Impactive
• Define Project Scope & Proceed in Parallel with IESO-CAA
• Determine if CIA Is Required
• Execute CIA Study Agreement
• Carry Out CIA (Examine Project Impacts on (i) Short Circuit (ii) Voltage Performance (iii) Supply Reliability (iv) Supply Capacity)
• Execute Preliminary Engineering Agreement
• Issue Draft CIA Report for Comment
• Issue Final CIA Report
• Request Connection Estimates
• Agree on Estimate Scope of Work
• Execute Pre-CCRA Long lead Items Agreement
• Review Customer Connection Electrical Design Package
• Determine Contestable & Uncontestable Connection Work
• Issue Technical Standards & Determine Project Costs
• Determine Customer Capital Contribution Requirements
• Submit Connection Estimates & Other Required Information
• Decide on Connection Facility Ownership
• Provide Mandatory Pre-requisites to Proceed with Connection
• Complete CCRA
• Receive Security Deposit(s)
• Execute CCRA
• Acquire Necessary Regulatory Approvals (i.e. MOE, OEB, ESA, Easements/Property, etc.)
• Modify Connection to Accommodate Regulatory Approvals, as Appropriate
• Initiate Connection Agreement Negotiations
• Award Work
• Use Technical Standards & Commissioning Requirements provided by Hydro One
• Confirm Requirements & Deliverables
• Complete Detailed Engineering & Project Design
• Procure Equipment & Material & Obtain Construction Approvals
• Construct Facilities
• Finalize Connection Agreement
• Commission Hydro One Facilities
• Submit Customer Commissioning Plan 30 Business Days in Advance
• Commission Customer Built Facilities
• Transfer Customer Built Facilities to Hydro One Ownership, as Appropriate
• Revise CCRA Based on Actual Connection Costs
• Submit As-Built Prints
• Manage CCRA & Connection Agreement
Customer Or Connection Applicant
IESO Customer Assessment & Approval Process
(Optional) Feasibility Study
System Impact Assessment or Expedited System Impact Assessment, As Appropriate
Required Path
Optional Path
Hydro One's "Customer Connection Process" and the Independent Electrical System Operator (IESO) "Connection Assessment and Approval Process" are separate processes that must both be implemented to obtain the necessary transmission system connection approvals.
Any Customer wishing to establish or modify a connection to Hydro One's transmission system must apply / register with both Hydro One and the IESO. However, Customers are strongly advised to initiate discussions with Hydro One prior to applying to the IESO for a connection assessment.

Additional Security Deposits

A customer may be required to provide additional security deposits at any time after Hydro One has executed an Agreement if (i) the customer is in default of a term of such an agreement and has not remedied the default within the cure period specified in the agreement or, if no cure period is specified in the agreement, a reasonable cure period; or (ii) if there is a material change in financial risk associated with a proposed new or modified connection. When a customer becomes aware of a material change in financial risk it must advise Hydro One of the change within 5 business days. Failure to do so will be considered a material breach of the agreement.

In a case where more than one customer triggers the need for a transmission upgrade, a customer may be required to provide an additional security deposit or extend the term of a security deposit after Hydro One has executed Agreements and collected initial security deposits. This would occur when a customer's proportional share of the upgrade cost increases because of other customer projects being delayed or cancelled that would have been contributors to the upgrade as originally planned and calculated in the Agreements.

INTRODUCTION

Hydro One's Customer Impact Assessment (CIA) Procedure was developed to meet the requirements of section 6.4.1 of the Transmission System Code (Code). As outlined in the Code, a transmitter is required to carry out CIA studies under certain circumstances and the following points are to be noted:

1. A CIA study is limited to assessing the impact of the new or modified connection on the supply at the transmission connection/delivery points to other transmission customers. It is the responsibility of other transmission customers to determine the consequential impacts and modifications on their own electrical facilities and to advise Hydro One, the IESO, the Board and the connection applicant accordingly. Hydro One will issue a draft of the CIA report to customers who may be potentially impacted by the connection and those customers are required to provide preliminary feedback. Hydro One will include the unedited version of this feedback in the final CIA report and Hydro One will not take responsibility for the contents of the other transmission customers' feedback.
2. The decision on the level of modifications at customers' facilities that can be attributed to the new or modified connection, as well as the assignment of cost responsibility for the identified modifications, are outside the scope of this procedure.

REQUIREMENT FOR A CIA STUDY

A Customer Impact Assessment study may be required for any new or modified connection to the IESO-controlled grid. Hydro One will undertake a CIA study for all cases where (i) the connection is one for which the IESO's CAA process requires a System Impact Assessment (SIA) or (ii) Hydro One determines that the connection may have a material impact on existing customers. The scope of the CIA study and report will be project-specific, depending on the complexity of the connection project and the extent of its impact on other transmission customers. For renewable energy projects awarded by OPA in accordance with O.Reg 326/09, the joint SIA/CIA phase of the process shall be completed within 150 days after the IESO and the transmitter deem the application complete for the purpose of completing SIA/CIA studies.

Where the IESO's CAA process triggers an SIA, the CIA procedure is mandatory. Where no SIA is required by the IESO, Hydro One may waive the requirement for a CIA study if the transmitter determines during its preliminary review that the new or modified connection will not materially impact other transmission customers. The transmitter may consult with the IESO prior to waiving the requirement for a CIA study. In cases where the requirement for a CIA study is waived, the transmitter will notify existing customers in the vicinity, advising them of the proposed new connection or modification and of the transmitter's decision not to carry out a CIA on the basis that no material customer impact is expected.

As a guideline, a CIA study may not be required for the following types of connection proposals:

- Like-for-like replacement of existing connection facilities where there is no connectivity change on the transmission system

4.0 SCHEDULE OF CHARGES & FEES

HYDRO ONE CUSTOMER CONNECTION PROCESS
SCHEDULE OF CHARGES & FEES
FOR TRANSMISSION CUSTOMERS

ACTIVITY	COST
Inspection, Testing and Commissioning Activities	Actual Costs
Engineering and Design Activities	Actual Costs

STUDIES	COST PER STUDY
Standard Customer Impact Assessment (CIA) Study	$15,000
Complex CIA Study	Actual Costs
Detailed Connection Estimate Studies	Actual Costs
Feasibility Studies	Actual Costs
Preliminary Engineering Agreement (PEA)	Actual Costs
Pre-CCRA Letter Agreement for Purchase of Long Lead Items	Actual Costs

In all cases the customer will enter into a Study Agreement with Hydro One.

For Standard CIA studies the scope of activities includes data acquisition and confirmation, load flow modeling & studies, short circuit modeling & studies, customer consultation and report preparation as outlined in the Study Agreement.

For CIA studies that are deemed “complex” by Hydro One and are undertaken for larger or more complex generator and load customer connections, the scope of work, deliverables, expected timelines and payment schedule will be determined on a case-by-case basis and specified in the Study Agreement.

For Detailed Connection Estimate Studies and Feasibility Studies, the scope of work, deliverables, expected timelines and payment schedule will be determined on a case-by-case basis and specified in the Study Agreement.

5.0 TIMELINES FOR CONNECTION PROCESS

Hydro One Customer Connection Process Timelines

	Timeline "On Best Efforts Basis"	Trigger
Phase 1 - Connection Application	~~14 Calendar Days~~1-2 months	From initial contact to date of completed Customer Joint (SIA/CIA) Application Form~~From Date of Submitted Customer Application Form~~
Phase 2 – Customer Impact Assessment (CIA)[1]	~~90 Calendar Days~~3-5 months	From Date of IESO Issuing Draft System Impact Assessment (SIA)
Phase 3 – Connection Estimates	~~45 Calendar Days~~4-8 months	From Date Estimate Agreement Executed~~From Date Electrical Design Package Received & Payment Received – As Appropriate.~~
Phase 4 – Connection Approval	1 month or longer if regulatory approvals, expropriation and permits are required ~~30 Calendar Days – or longer if EA & Other Regulatory Approvals are Required~~	From Date of Issuing Draft Connection Cost Recovery Agreement (CCRA) for Customer Signature~~From Date of Issuing Draft Connection Cost Recovery Agreement (CCRA) for Customer Signature~~
Phase 5 – Design & Build	Project Specific (normally 12 to 24 months) To be negotiated with customers as per CCRA terms. ~~Project Specific (Up to 2 years) – To Be Negotiated With Customer as per CCRA~~	Execution of CCRA ~~As per CCRA~~
Phase 6 - Commissioning	1-2 months ~~45 Calendar Days~~	Signing of Connection Agreement[2]~~From Date of Signed Connection Agreement (Customer must submit a commissioning plan to Hydro One at least 30 business days prior to proposed commissioning tests)~~

Notes:

1. For renewable generators, the timeline for combined SIA/CIA process is 150 days (5months) from the completion of the application as per OREG 326/09

~~1.~~2. Customer must submit a commissioning plan to Hydro One 30 days before proposed commissioning tests.

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