Ontario Energy Board

Commission de l’énergie de l’Ontario

Ontario

EB-2008-0272

IN THE MATTER OF the *Ontario Energy Board Act 1998*, S.O.1998, c.15, Schedule B;

AND IN THE MATTER OF an Application by Hydro One Networks Inc. for an Order under section 78 of the *Ontario Energy Board Act, 1998,* seeking changes to the uniform provincial transmission rates.

BEFORE: Cynthia Chaplin
Presiding Member

Paul Vlahos
Member

Ken Quesnelle
Member

REVISED
REVENUE REQUIREMENT AND CHARGE DETERMINANT ORDER ARISING FROM THE EB-2008-0272 DECISION WITH REASONS

Hydro One Networks Inc. (“Hydro One”) filed an application dated September 30, 2008 with the Ontario Energy Board (the “Board”) under section 78 of the *Ontario Energy Board Act, 1998*; S.O. c.15, (Sched. B) (the “Act”), for an order or orders approving the revenue requirements for the test years 2009 and 2010; customer rates for the transmission of electricity to be implemented on July 1, 2009; the inclusion into rate base of certain capital costs; and other matters related to the fixing of just and reasonable rates for the transmission of electricity. The Board assigned file number EB-2008-0272 to the application and issued a Notice of Application dated October 17, 2008. Updates to certain parts of the application were filed on February 13, 2009.

The Board's EB-2008-0272 Decision with Reasons (the "Decision") was issued on May 28, 2009. The Board directed Hydro One to file with the Board and all intervenors exhibits outlining draft final revenue requirements and charge determinants for 2009 and 2010, as well as the calculation of the Uniform Transmission Rates ("UTRs"), charge determinants and revenue shares resulting from the Decision.

Hydro One filed the required exhibit on June 11, 2009. One intervenor responded. The Vulnerable Energy Consumers Coalition suggested that Hydro One had not taken into account that annualized rates would result in less of a refund than is required because the rates were to be implemented at July 1, 2009. Hydro One responded in a letter of June 23, 2009 that the calculation did in fact take into account that the new UTRs would be in effect for only six months. Upon reviewing the letters, the Board is satisfied that VECC's concern has been addressed.

On June 15, 2009 the Board provided a Notice of Opportunity to Comment on Proposed Uniform Transmission Rates Effective July 1, 2009 to Canadian Niagara Power Inc., Great Lakes Power Limited ("GLPL") and Five Nations Energy Inc., the other transmitters in the Province that are included in the UTRs.

GLPL responded and provided an update to its annual charge determinants and submissions in support of a change to the Transformation Connection Pool charge. The Board has determined that the material is untested evidence and is out of scope for this proceeding on the implementation of Hydro One's revenue requirements.

Upon reviewing the materials, the Board finds it appropriate to issue a final order regarding Hydro One's 2009 Test Year revenue requirements and charge determinants for use in the implementation of the Ontario Uniform Transmission rates.

THEREFORE, THE BOARD ORDERS THAT:

1. The Hydro One Base Revenue Requirements for 2009 and 2010, $1,179.0 million and $1,242.2 million respectively, as shown in Exhibit 1.0 in Appendix A are approved for recovery through the Uniform Transmission Rates. The 2010 Base Revenue Requirement will be updated in future to include updated cost of capital numbers and possibly other matters that would be the subject of an application.

2. The allocation of the approved revenue requirements to the three transmission rate pools as shown in Exhibit 2.0 in Appendix A is approved.

3. The Hydro One charge determinants for each rate pool as shown in Exhibit 3.0 in Appendix A are approved.

4. The final revenue requirement by rate pool for determining Uniform Transmission rates for July 1, 2009 to December 31, 2009 as shown in Exhibit 4.0 is approved.

5. The Wholesale Meter Service and Exit Fee Schedule, attached as Exhibit 5.0 in Appendix A, is approved.

ISSUED at Toronto, July 3, 2009

ONTARIO ENERGY BOARD

Original Signed By

John Pickernell
Assistant Board Secretary

APPENDIX “A” TO

HYDRO ONE NETWORKS INC. TRANSMISSION REVENUE REQUIREMENT

AND CHARGE DETERMINANT ORDER

BOARD FILE NO. EB-2008-0272

DATED: July 3, 2009

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EB-2008-0272 BOARD DECISION WITH REASONS
FINAL REVENUE REQUIREMENTS AND CHARGE DETERMINANTS

Hydro One Networks Inc.

Implementation of Decision with Reasons on EB-2008-0272

Revenue Requirement Summary

($ millions)	Supporting Reference	Hydro One Proposed 2009	Hydro One Proposed 2010	OEB Decision Impact 2009	OEB Decision Impact 2010	OEB Approved 2009	OEB Approved 2010
OM&A	Exhibit 1.1	435.2	449.7	(20.2)	(23.5)	415.0	426.2
Depreciation	Exhibit 1.2	258.0	281.5	-	(1.8)	258.0	279.7
Capital Tax	Exhibit 1.5	16.4	6.0	-	(0.1)	16.4	5.9
Return on Debt	Exhibit 1.4	251.2	269.7	(11.6)	(16.3)	239.6	253.4
Return on Equity	Exhibit 1.4	240.0	286.1	(14.7)	(39.4)	225.3	246.7
Income Tax	Exhibit 1.6	31.9	48.0	(7.2)	(17.7)	24.7	30.3
Base Revenue Requirement		**1,232.7**	**1,341.0**	**(53.7)**	**(98.8)**	**1,179.0**	**1,242.2**
Deduct: External Revenue	Exhibit 1.7 & Note 1	18.6	18.0	-	-	18.6	18.0
Revenue Requirement less external revenues		**1,214.1**	**1,323.0**	**(53.7)**	**(98.8)**	**1,160.4**	**1,224.2**
Deduct: Export Revenue Credit	Note 1	(12.0)	(12.0)	-	-	(12.0)	(12.0)
Deduct: Other Cost Charges	Exhibit 1.8	(14.0)	(13.0)	(0.2)	(7.3)	(14.2)	(20.3)
Add: Low Voltage Switch Gear	Note 2	10.7	11.5	(0.4)	(0.5)	10.3	11.0
Rates Revenue Requirement		**1,198.8**	**1,309.5**	**(54.3)**	**(106.6)**	**1,144.5**	**1,202.9**

Note 1: Variance accounts will be established for export revenues, secondary land use and work for other parties to track changes from approved amounts.
Note 2: The value for 2010 LVSG is an estimate and will be revised once the 2010 Revenue Requirement is finalized in the fall of 2009

Hydro One Networks Inc.

Implementation of Decision with Reasons on EB-2008-0272

OM&A Details

($ millions)	**Supporting Reference**	**Hydro One Proposed 2009**	**Hydro One Proposed 2010**	**OEB Decision Impact 2009**	**OEB Decision Impact 2010**	**OEB Approved 2009**	**OEB Approved 2010**
OM&A	*See supporting details below*	435.2	449.7	(20.2)	(23.5)	415.0	426.2

OEB Decision Impact Supporting Details

	Reference		
Sustainment OM&A adjustment	OEB Decision pg. 21	(15.0)	(15.0)
Development OM&A adjustment	OEB Decision pg. 23		(3.2)
Compensation adjustment	OEB Decision pg. 31	(4.0)	(4.0)
Property Tax adjustment	OEB Decision pg. 33	(1.2)	(1.3)
		(20.2)	(23.5)

Hydro One Networks Inc.

Implementation of Decision with Reasons on EB-2008-0272

Rate Base and Depreciation Details

($ millions)	Supporting Reference	Hydro One Proposed 2009	Hydro One Proposed 2010	OEB Decision Impact 2009	OEB Decision Impact 2010	OEB Approved 2009	OEB Approved 2010
Rate Base	*See supporting details below*	7,033.8	7,650.5	(2.2)	(91.6)	7,031.6	7,558.9
Depreciation	*See supporting details below*	258.0	281.5	-	(1.8)	258.0	279.7

OEB Decision Impact Supporting Details	**Reference**	**2009 Detailed Computation**	**2010 Detailed Computation**	**2009 Rate Base Impact**	**2010 Rate Base Impact**	**2009 Depreciation Impact**	**2010 Depreciation Impact**
Working Capital Adjustment							
Rate Base Details	Pre-filed Evidence Exh						
Utility plant (average)	D1-1-1						
Gross plant at cost		10,940.0	11,780.2				
Less: Accumulated depreciation		(3,954.4)	(4,179.7)				
Net utility plant		6,985.6	7,600.5				
Working capital							
Cash working capital		11.6	11.2				
Materials & supplies inventory		36.7	38.7				
Total working capital		48.3	50.0				
Total Rate Base		7,033.8	7,650.5				
Working capital as % of OM&A	(a)	11.1%	11.1%				
OM&A Reduction	Exhibit 1.1 (b)	(20.2)	(23.5)				
Working capital reduction	(c) = (a) x (b)	(2.2)	(2.6)	(2.2)	(2.6)		
Rate Base Adjustment							
Development Capital							
D7 - SVCs at Porcupine and Kirkland	Prefiled Evidence	-	108.6				
D8 - Series Caps at Nobel SS	D1-3-3	-	47.2				
D9 - 100MVar Shunt Caps at Algoma		-	9.7				
D10 - 2 75MVAR Shunt Caps at Mississagi		-	10.3				
D28 - Glendale TS - increase capacity		-	3.2				
D29 - Dunnville TS - increase capacity		-	0.8				
		-	179.8				
Associated Depreciation	*Note 1*	-	1.8				(1.8)
Development Capital Adjustment	*Note 2*	-	178.0		(89.0)		
Reduction to proposed				(2.2)	(91.6)	-	(1.8)

Note 1: Assumed 50 year service life and half year depreciation
Note 2: The 2010 net adjustment would be a half year impact on 2010 rate base

Hydro One Networks Inc.
Implementation of Decision with Reasons on EB-2008-0272

Capital Expenditure Details

($ millions)	**Supporting Reference**	**Hydro One Proposed 2009**	**Hydro One Proposed 2010**	**OEB Decision Impact 2009**	**OEB Decision Impact 2010**	**OEB Approved 2009**	**OEB Approved 2010**
Capital expenditures	*See supporting details below*	944.0	1,074.1	(90.2)	(78.5)	**853.8**	**995.6**

OEB Decision Impact Supporting Details

Development Capital			
D7 - SVCs at Porcupine and Kirkland	Pre-filed Evidence	48.5	54.8
D8 - Series Caps at Nobel SS	Exh D1-3-3	34.2	7.2
D9 - 100MVar Shunt Caps at Algoma		4.6	5.1
D10 - 2 75MVAR Shunt Caps at Mississagi		2.9	7.4
D28 - Glendale TS - increase capacity	*Note 1*	-	3.2
D29 - Dunnville TS - increase capacity	*Note 1*	-	0.8
		90.2	78.5

Note 1: Net of capital contributions
Note 2: 6 Development projects were removed from the revenue requirement calculation based on the OEB Decision. Hydro One will have the opportunity to submit additional evidence to justify the inclusion in rate base by the Board of 4 projects (D7, D8, D9 and D10) by November 30, 2009.

Hydro One Networks Inc.

Implementation of Decision with Reasons on EB-2008-0272

Capital Structure and Return on Capital Details

($ millions)	**Supporting Reference**	**Hydro One Proposed 2009**	**Hydro One Proposed 2010**	**OEB Decision Impact 2009**	**OEB Decision Impact 2010**	**OEB Approved 2009**	**OEB Approved 2010**
Return on Rate Base							*Note 3*
Rate Base	Exhibit 1.2	$ 7,033.8	$ 7,650.5	$ (2.2)	$ (91.6)	$ 7,031.6	$ 7,558.9
Capital Structure:							
Third-Party long-term debt	OEB Decision pg. 54	53.1%	56.0%	1.6%	2.0%	54.6%	58.0%
Deemed long-term debt	OEB Decision pg. 54	2.9%	0.0%	(1.6%)	(2.0%)	1.4%	-2.0%
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		3,733.2	4,284.0	108.9	99.6	3,842.0	4,383.6
Deemed long-term debt		205.8	0.3	(110.1)	(150.9)	95.7	(150.7)
Short-term debt		281.4	306.0	(0.1)	(3.7)	281.3	302.4
Common equity		2,813.5	3,060.2	(0.9)	(36.6)	2,812.6	3,023.6
		$ 7,033.8	**$ 7,650.5**	**$ (2.2)**	**$ (91.6)**	**$ 7,031.6**	**$ 7,558.9**
Allowed Return:							
Third-Party long-term debt	Exhibit 1.4.1 and 1.4.2	5.90%	5.80%	(0.06%)	(0.05%)	5.84%	5.76%
Deemed long-term debt	Exhibit 1.4.1 and 1.4.2	6.19%	7.29%	(0.35%)	(1.53%)	5.84%	5.76%
Short-term debt	*Note 1*	4.47%	4.75%	(3.14%)	(3.42%)	1.33%	1.33%
Common equity	*Note 1*	8.53%	9.35%	(0.52%)	(1.19%)	8.01%	8.16%
Return on Capital:							
Third-Party long-term debt	Prefiled Evidence	220.4	248.5	4.1	3.8	224.5	252.3
Deemed long-term debt	B2-1-1	12.7	0.0	(7.1)	(8.7)	5.6	(8.7)
Short-term debt		12.6	14.5	(8.8)	(10.5)	3.7	4.0
AFUDC return on Niagara Reinforcement Project	see below	5.5	6.6	0.3	(0.9)	5.8	5.7
Total return on debt		**$ 251.2**	**$ 269.7**	**$ (11.6)**	**$ (16.3)**	**$ 239.6**	**$ 253.4**
Common equity		**$ 240.0**	**$ 286.1**	**$ (14.7)**	**$ (39.4)**	**$ 225.3**	**$ 246.7**
AFUDC return on Niagara Reinforcement Project							
CWIP		99.1	99.1			99.1	99.1
AFUDC Rate	*Note 2*	5.6%	6.7%			5.84%	5.76%
		5.5	6.6			5.8	5.7

Note 1: per February 24, 2009 Cost of Capital Report

Note 2: used embedded cost of debt return for NRP

Note 3: the cost of capital parameters & impacts used for 2010 are illustrative. Hydro One will submit a 2010 draft rate order to the OEB reflecting the cost of capital parameters issued by the Board once the September 2009 consensus forecast becomes available. At that point we will apply these up-to-date cost of capital parameters.

HYDRO ONE NETWORKS INC.
TRANSMISSION
Cost of Long-Term Debt Capital
Test Year (2009) Updated for 2008 Actuals
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 $100 Principal Amount (Dollars)	Effective Cost Rate	Total Amount Outstanding at 12/31/08 ($Millions)	Total Amount Outstanding at 12/31/09 ($Millions)	Avg. Monthly Averages ($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	7.150%	3-Jun-10	278.4	3.6	274.8	98.70	7.34%	278.4	278.4	278.4	20.4	
2	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	
3	22-Jun-01	6.400%	1-Dec-11	174.0	(0.5)	174.5	100.28	6.36%	174.0	174.0	174.0	11.1	
4	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	
5	17-Sep-02	5.770%	15-Nov-12	87.0	0.4	86.6	99.55	5.83%	87.0	87.0	87.0	5.1	
6	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	
7	31-Jan-03	5.770%	15-Nov-12	189.0	(0.9)	189.9	100.48	5.70%	189.0	189.0	189.0	10.8	
8	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	
9	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	
10	24-Feb-04	3.950%	24-Feb-09	162.5	0.7	161.8	99.55	4.05%	162.5	0.0	25.0	1.0	
11	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	
12	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	
13	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	
14	19-May-05	5.360%	20-May-36	228.9	8.2	220.7	96.44	5.60%	228.9	228.9	228.9	12.8	
15	19-May-05	3.950%	24-Feb-09	105.0	(0.9)	105.9	100.90	3.69%	105.0	0.0	16.2	0.6	
16	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	
17	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	
18	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	
19	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	
20	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	
21	18-Oct-07	5.180%	18-Oct-17	225.0	0.8	224.2	99.66	5.22%	225.0	225.0	225.0	11.8	
22	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	
23	10-Nov-08	5.000%	12-Nov-13	240.0	1.1	238.9	99.53	5.11%	240.0	240.0	240.0	12.3	
24	19-Nov-08	3.890%	19-Nov-10	60.0	0.1	59.9	99.78	4.01%	60.0	60.0	60.0	2.4	
25	15-Mar-09	5.770%	15-Mar-39	337.0	1.7	335.3	99.50	5.81%	0.0	337.0	259.2	15.0	
26	15-Jun-09	5.070%	15-Jun-19	337.0	1.7	335.3	99.50	5.13%	0.0	337.0	181.5	9.3	
27	15-Sep-09	4.380%	15-Sep-14	337.0	1.7	335.3	99.50	4.49%	0.0	337.0	103.7	4.7	
28		**Subtotal**							3524.0	4267.5	3842.0	221.8	
29		Treasury OM&A costs										1.9	
30		Other financing-related fees										0.8	
31		**Total**							3524.0	4267.5	3842.0	224.5	5.8437%

HYDRO ONE NETWORKS INC.
TRANSMISSION
Cost of Long-Term Debt Capital
Test Year (2010) Updated for 2008 Actuals
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 $100 Principal Amount (Dollars)	Effective Cost Rate	Total Amount Outstanding: at 12/31/09 ($Millions)	Total Amount Outstanding: at 12/31/10 ($Millions)	Avg. Monthly Averages ($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	7.150%	3-Jun-10	278.4	3.6	274.8	98.70	7.34%	278.4	0.0	128.5	9.4	
2	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	
3	22-Jun-01	6.400%	1-Dec-11	174.0	(0.5)	174.5	100.28	6.36%	174.0	174.0	174.0	11.1	
4	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	
5	17-Sep-02	5.770%	15-Nov-12	87.0	0.4	86.6	99.55	5.83%	87.0	87.0	87.0	5.1	
6	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	
7	31-Jan-03	5.770%	15-Nov-12	189.0	(0.9)	189.9	100.48	5.70%	189.0	189.0	189.0	10.8	
8	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	
9	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	
10	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	
11	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	
12	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	
13	19-May-05	5.360%	20-May-36	228.9	8.2	220.7	96.44	5.60%	228.9	228.9	228.9	12.8	
14	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	
15	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	
16	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	
17	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	
18	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	
19	18-Oct-07	5.180%	18-Oct-17	225.0	0.8	224.2	99.66	5.22%	225.0	225.0	225.0	11.8	
20	3-Mar-08	5.180%	18-Oct-17	180.0	(3.1)	183.1	101.74	4.95%	180.0	180.0	180.0	8.9	
21	10-Nov-08	5.000%	12-Nov-13	240.0	1.1	238.9	99.53	5.11%	240.0	240.0	240.0	12.3	
22	19-Nov-08	3.890%	19-Nov-10	60.0	0.1	59.9	99.78	4.01%	60.0	0.0	50.8	2.0	
23	15-Mar-09	5.770%	15-Mar-39	337.0	1.7	335.3	99.50	5.81%	337.0	337.0	337.0	19.6	
24	15-Jun-09	5.070%	15-Jun-19	337.0	1.7	335.3	99.50	5.13%	337.0	337.0	337.0	17.3	
25	15-Sep-09	4.380%	15-Sep-14	337.0	1.7	335.3	99.50	4.49%	337.0	337.0	337.0	15.1	
26	15-Mar-10	6.870%	15-Mar-40	170.4	0.9	169.6	99.50	6.91%	0.0	170.4	131.1	9.1	
27	15-Jun-10	6.170%	15-Jun-20	170.4	0.9	169.6	99.50	6.24%	0.0	170.4	91.8	5.7	
28	15-Sep-10	5.480%	15-Sep-15	170.4	0.9	169.6	99.50	5.60%	0.0	170.4	52.4	2.9	
29		**Subtotal**							4267.5	4440.3	4383.6	249.5	
30		Treasury OM&A costs										2.0	
31		Other financing-related fees										0.8	
32		**Total**							4267.5	4440.3	4383.6	252.3	5.7556%

Hydro One Networks Inc.

Implementation of Decision with Reasons on EB-2008-0272

Capital Tax Summary

($ millions)	**Supporting Reference**	**Hydro One Proposed 2009**	**Hydro One Proposed 2010**	**OEB Approved 2009**	**OEB Approved 2010**	**OEB Decision Impact 2009**	**OEB Decision Impact 2010**
Capital Taxes	*See supporting details below*	16.4	6.0	16.4	5.9	-	(0.1)

Capital Tax Supporting Details

($ millions)	**Reference**			
Net Taxable Capital as filed	Pre-filed Evidence Exh C2/T4/S1	7,298.1	7,985.8	(a)
Capital Tax rate		0.225%	0.075%	(b)
Capital Tax as filed		16.4	6.0	(c) = (a) * (b)
2010 in-service additions	Exhibit 1.2	-	179.8	
Associated depreciation	Exhibit 1.2	-	(1.8)	
Total net taxable capital adjustments		-	178.0	(d)
Revised Taxable Capital		7,298.1	7,807.8	(e) = (a) - (d)
Revised Capital Taxes		16.4	5.9	(f) = (e) x (b)

Hydro One Networks Inc.
Implementation of Decision with Reasons on EB-2008-0272

Income Tax Summary

($ millions)	Supporting Reference	Hydro One Proposed 2009	Hydro One Proposed 2010	OEB Approved 2009	OEB Approved 2010	OEB Decision Impact 2009	OEB Decision Impact 2010
Income Taxes	*See supporting details below*	31.9	48.0	24.7	30.3	(7.2)	(17.7)

Income Tax Supporting Details

Rate Base	Exhibit 1.2	a	$ 7,033.8	$ 7,650.5	$ 7,031.6	$ 7,558.9		
Common Equity Capital Structure		b	40.0%	40.0%	40.0%	40.0%		
Return on Equity	Exhibit 1.4	c	8.53%	9.35%	8.01%	8.16%		
Return on Equity		d = a x b x c	240.0	286.1	225.3	246.7		
Regulatory Income Tax		e = l	31.9	48.0	24.7	30.4		
Regulatory Net Income (before tax)		f = d + e	271.9	334.1	250.0	277.2	(21.9)	(57.0)
Timing Differences *(Note 1)*		g	(174.0)	(182.9)	(174.0)	(181.1)	-	1.8
Taxable Income		h = f + g	97.9	151.2	76.0	96.1	(21.9)	(55.2)
Tax Rate	Prefiled Evidence	i	33.0%	32.0%	33.0%	32.0%		
Income Tax	C2-6-1	j = h x i	32.3	48.4	25.1	30.7		
less: Income Tax Credits		k	(0.4)	(0.4)	(0.4)	(0.4)		
Regulatory Income Tax		l = j + k	31.9	48.0	24.7	30.3	(7.2)	(17.7)

Note 1. Book to Tax Timing Differences are detailed in EB-2008-0272 C2-6-1. The adjustment above to timing differences reflect the change between capital cost allowance and depreciation as a result of the change in rate base as directed in section 6.5 of the OEB decision.

Timing difference adjustments	
less: lower depreciation related to development project adjustment	(1.8)
add: lower CCA claim related to development project adjustment	3.6
Net timing difference adjustment	1.8

Hydro One Networks Inc.
Implementation of Decision with Reasons on EB-2008-0272

External Revenue Details

($ millions)	Supporting Reference	Hydro One Proposed 2009	Hydro One Proposed 2010	OEB Decision Impact 2009	OEB Decision Impact 2010	OEB Approved 2009	OEB Approved 2010
External Revenue	Pre-filed Evidence Exh E3/T1/S1 & Note 1	18.6	18.0	-	-	18.6	18.0

Note 1: Variance accounts will be established for export revenues, secondary land use and work for other parties to track changes from approved amounts.

Hydro One Networks Inc.

Implementation of Decision with Reasons on EB-2008-0272

Deferral Account Recovery Details

($ millions)	Supporting Reference	EB-2006-0501 Approved for 2009&2010	Hydro One Proposed Jun 30, 2009	Total Deferral Account Recovery		OEB Decision 2009	OEB Decision 2010
Requested Deferral Account Recovery	*Note 1*						
Tax Changes Account	Pre-filed		(13.9)	(13.9)		(4.6)	(9.3)
OEB Costs Account	Evidence Exh		(4.2)	(4.2)		(1.4)	(2.8)
Pension Account	F1/T1/S1		(0.2)	(0.2)		(0.1)	(0.1)
Total Requested Deferral Account Recovery		**-**	**(18.3)**	**(18.3)**		**(6.1)**	**(12.2)**
Add:							
Existing Deferral Account Recovery							
MRP costs	EB-2006-0501	8.2		8.2		4.1	4.1
Export revenue	Board Order	(24.4)		(24.4)		(12.2)	(12.2)
Total Existing Deferral Account Recovery		**(16.2)**	**-**	**(16.2)**		**(8.1)**	**(8.1)**
Total Deferral Account Recovery		**(16.2)**	**(18.3)**	**(34.5)**		**(14.2)**	**(20.3)**

Note 1: 2009 requested deferral account recovery for 6 months only; 2010 amount is for 12 months

Hydro One Networks Inc.

Implementation of Decision with Reasons on EB-2008-0272

Final 2009 Revenue Requirement by Rate Pool

	Supporting Exhibit	2009 Rate Pool Revenue Requirement ($ Million)					
		Network	Line Connection	Transformation Connection	Uniform Rates Sub-Total	Wholesale Meter	Total
OM&A	*1.0*	194.5	39.5	110.2	344.3	1.0	345.3
Other Taxes (Grants-in-Lieu)	*1.0*	41.8	11.3	16.5	69.6	0.0	69.7
Depreciation of Fixed Assets	*1.0*	142.6	36.0	71.5	250.1	0.1	250.2
Capitalized Depreciation	*Note 1*	(7.2)	(2.0)	(3.0)	(12.2)	(0.0)	(12.2)
Asset Removal Costs	*Note 1*	10.5	2.9	4.4	17.8	0.0	17.8
OPEB Amortization	*Note 1*	0.0	0.0	0.0	0.0	0.0	0.0
Other Amortization	*Note 1*	1.3	0.3	0.5	2.1	0.0	2.1
Return on Debt	*1.0*	143.7	38.9	56.9	239.5	0.1	239.6
Return on Equity	*1.0*	135.1	36.6	53.5	225.2	0.1	225.3
Income Tax	*1.0*	14.8	4.0	5.9	24.7	0.0	24.7
Capital Tax	*1.0*	9.9	2.7	3.9	16.4	0.0	16.4
Base Revenue Requirement	*1.0*	**687.0**	**170.3**	**320.3**	**1177.5**	**1.4**	**1179.0**
Less Regulatory Asset Credit	*1.8*	-8.3	-2.1	-3.9	-14.2	0.0	-14.2
Total Revenue Requirement	1.0	**678.7**	**168.2**	**316.4**	**1163.3**	**1.4**	**1164.7**
Less Non-Rate Revenues	*Note 1*	(10.8)	(2.7)	(5.0)	(18.6)	(0.0)	(18.6)
Less Export Revenues	*Note 1*	(12.0)			(12.0)		(12.0)
Plus LVSG Credit	*6.0*			10.3	10.3		10.3
Revenue Requirement by Pool		**655.9**	**165.6**	**321.7**	**1143.1**	**1.4**	**1144.5**
Full year impact of Requested Deferral Accounts		**(3.5)**	**(0.9)**	**(1.7)**	**(6.1)**	**0.0**	**(6.1)**
Revenue Requirement for UTR	*Note 2*	**652.4**	**164.7**	**319.9**	**1136.9**		**1138.4**
Hydro One Proposed Pool Revenue Requirement	*Note 1*	688.0	173.4	336.4	1197.8	1.5	1199.3

Note 1: See EB-2008-0272 Exhibit G2, Tab 5, Schedule 1, Page 1.

Note 2: Hydro One Networks (H1N) 2009 Revenue Requirement adjusted for the annual equivalent of the OEB directed refund of requested Deferral Accounts as per Exhibit 1.8 as follows: Network $(3.50) million, Line Connection $(0.89) million and Transformation Connection $(1.72) million. This was done in order to ensure customers receive the full refund of $6.1 million applicable for 2009

Hydro One Networks Inc.

Implementation of Decision with Reasons on EB-2008-0272

Summary Final Charge Determinants
(for Setting Uniform Transmission Rates for July 1, 2009 to December 31, 2009)

	Total MW
Network	250,101
Line Connection	241,201
Transformation Connection	208,518

2009 charge determinants per Exhibit H1, Tab 3, Schedule 1, Table 1, multiplied by 12.

Hydro One Networks Inc.

Implementation of Decision with Reasons on EB-2008-0272

Summary Uniform Transmission Rates and Revenue Disbursement Factors
(for Period July 1, 2009 to December 31, 2009)

Transmitter	Revenue Requirement ($) *(Note 3, Note 4)*			
	Network	Line Connection	Transformation Connection	Total
FNEI	$2,971,016	$749,913	$1,457,071	$5,178,000
CNPI	$2,646,512	$668,006	$1,297,925	$4,612,443
GLPL	$19,959,065	$5,037,863	$9,788,494	$34,785,422
H1N *(Note 1)*	$652,352,000	$164,660,000	$319,932,000	$1,136,944,000
All Transmitters	$677,928,594	$171,115,781	$332,475,490	$1,181,519,865

Transmitter	Total Annual Charge Determinants (MW) *(Note 3, Note 4)*			
	Network	Line Connection	Transformation Connection	
FNEI	44.915	44.915	44.915	
CNPI	583.420	668.600	668.600	
GLPL	4,150.498	2,847.032	2,777.933	
H1N *(Note 2)*	250,100.712	241,200.708	208,517.964	
All Transmitters	254,879.545	244,761.255	212,009.412	

Transmitter	Uniform Rates and Revenue Allocators *(Note 4)*			
	Network	Line Connection	Transformation Connection	
Uniform Transmission Rates ($/kW-Month)	**2.66**	**0.70**	**1.57**	
	↓	↓	↓	
FNEI Allocation Factor	**0.00438**	**0.00438**	**0.00438**	
CNPI Allocation Factor	**0.00390**	**0.00390**	**0.00390**	
GLPL Allocation Factor	**0.02944**	**0.02944**	**0.02944**	
H1N Alocation Factor	**0.96228**	**0.96228**	**0.96228**	
Total of Allocation Factors	1.00000	1.00000	1.00000	

Note 1: Hydro One Networks (H1N) 2009 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.

Implementation of Decision with Reasons on EB-2008-0272

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 (FNEI)	5,178,000	44.915	44.915	44.915	*Note 1*
Canadian Niagara Power (CNPI)	4,612,443	583.420	668.600	668.600	*Note 2*
Great Lakes Power (GLPL)	34,785,422	4,150.498	2,847.032	2,777.933	*Note 3*

Note 1: Board Decision on RP-2001-0036 dated April 24, 2002, pages 23 and 26.

Note 2: Board Decision on RP-2001-0034 dated December 11, 2001, pages 8 and 10.

Note 3:Revenue Requirement per Settlement Agreement on EB-2005-0241, Appendix B, page 5 of 5, approved by the Board September 15, 2005. Charge Determinants per Board Decision on RP-2001-0035 dated December 11, 2001, page 11.

HYDRO ONE NETWORKS INC.
Ontario, Canada

WHOLESALE METER SERVICE
And
EXIT FEE SCHEDULE

Rate Schedule: HON-MET
Issued: July 3, 2009
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 $ 7,300 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 Decision with Reasons on EB-2008-0272

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 2*		
	(A)	(B)	(B) / (A)	
2009	188	1.4	7,300	7,300

* Rate is rounded down to the nearest $100

Note 1: Per EB-2008-0272, Exhibit H1, Tab 4, Schedule 1, Table 1.
Note 2: Per Exhibit 2.1

Hydro One Networks Inc.

Implementation of Decision with Reasons on EB-2008-0272

Low Voltage Switchgear (LVSG) Credit
Effective July 1, 2009

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)
208,518	311.4	1.493	3018	19.0%	10.27

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 2.1.

Note 3: Per Exhibit G1, Tab 4, Schedule 1, Table 1

Note 4: See EB-2006-0501 Exhibit G1, Tab 4, Schedule 1, page 2.

The LVSG Credit effective July 1, 2009 is $10.27 million or $856,000 per month.

APPENDIX B

ONTARIO TRANSMISSION RATE SCHEDULES
EB-2008-0272

The rate schedules contained herein shall be effective July 1, 2009.

Issued: July 3, 2009
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 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]	2.66
Line Connection Service Rate (PTS-L):	
$ Per kW of Line Connection Billing Demand [1,3]	0.70
Transformation Connection Service Rate (PTS-T):	
$ Per kW of Transformation Connection Billing Demand [1,3,4]	1.57

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.

APPLICABILITY:

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

Hourly Rate

Export Transmission Service Rate (ETS): $1.00 / 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.

Appendix “C” to

ONTARIO UNIFORM RATE ORDER

EB-2008-0272

July 3, 2009

ONTARIO UNIFORM RATE ORDER

REVENUE ALLOCATORS

Effective July 1, 2009

Transmitter	Network	Line Connection	Transformation Connection
Five Nations Energy Inc.	0.00438	0.00438	0.00438
Canadian Niagara Power Inc.	0.00390	0.00390	0.00390
Great Lakes Power Ltd.	0.02944	0.02944	0.02944
Hydro One Networks Inc.	0.96228	0.96228	0.96228
Total	1.00000	1.00000	1.00000