2008	2009	2010	2011	2012	2013	2014	2015	2016
151,857	151,857	151,857	0	0	0	0	0	0
11,574	11,574	11,574	11,574	11,574	11,574	11,574	11,574	11,574
6,217	6,217	6,217	6,217	0	0	0	0	0
246,359	246,359	246,359	246,359	246,359	0	0	0	0
0	0	0	0	0	0	0	0	0
416,007	**416,007**	**416,007**	**264,150**	**257,933**	**11,574**	**11,574**	**11,574**	**11,574**
33,712	33,712	33,712	33,712	33,530	33,530	33,530	27,930	0
57,469	57,469	57,469	57,469	50,864	50,864	50,864	50,864	50,864
19,797	19,797	19,797	0	0	0	0	0	0
184,252	184,252	184,252	184,252	165,622	165,622	165,622	17,932	17,932
0	0	0	0	0	0	0	0	0
675,000	0	0	0	0	0	0	0	0
4,254	4,254	4,254	4,254	4,254	4,254	4,254	4,254	4,254
11,900	11,900	11,900	11,900	11,900	11,900	11,900	11,900	11,900
2,300	2,300	2,300	2,300	2,300	2,300	2,300	2,300	2,300
184,100	184,100	184,100	184,100	0	0	0	0	0
5,556	5,556	5,556	5,556	0	0	0	0	0
0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0
8,607	8,607	8,607	8,607	8,607	8,607	8,607	8,607	8,607
1,186,946	**511,946**	**511,946**	**492,149**	**277,077**	**277,077**	**277,077**	**123,786**	**95,856**
62,711	62,711	62,711	62,711	62,398	62,398	62,398	62,398	48,800
40,725	40,725	40,725	40,725	40,725	40,725	40,725	40,725	40,725
0	0	0	0	0	0	0	0	0
48,142	17,372	17,372	17,372	17,372	17,372	17,372	17,372	9,517
294,528	293,056	293,056	293,056	246,692	246,692	205,044	167,916	120,070
757	757	757	757	757	757	757	757	757
97,310	97,309	97,309	97,309	97,309	97,309	97,309	97,309	89,372
99,960	99,917	99,137	99,137	99,137	98,878	98,878	98,878	92,425
410	410	410	410	410	410	410	410	410
3,447	3,447	2,825	2,825	2,825	2,825	2,825	2,802	2,802
0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0
2,118	2,118	2,118	2,118	2,118	2,118	2,118	2,118	2,118
27,498	27,498	27,498	27,498	27,498	27,498	27,498	27,498	27,498
677,605	**645,319**	**643,918**	**643,918**	**597,241**	**596,982**	**555,334**	**518,183**	**434,492**
2,280,559	**1,573,273**	**1,571,872**	**1,400,217**	**1,132,252**	**885,634**	**843,986**	**653,544**	**541,923**

Gross								
Annual Energy Savings (MWh)								
2017	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
0	0	0	0	0	0	0	0	0
309	309	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0
309	**309**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
0	0	0	0	0	0	0	0	0
1,413	1,413	1,413	1,413	1,413	140	140	140	0
0	0	0	0	0	0	0	0	0
89	89	89	89	89	50	19	19	0
0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0
1,502	**1,502**	**1,502**	**1,502**	**1,502**	**190**	**159**	**159**	**0**
0	0	0	0	0	0	0	0	0
1,126	1,126	1,126	1,126	1,126	1,126	899	899	899
0	0	0	0	0	0	0	0	0
33	25	25	25	22	21	20	20	20
3,325	2,821	2,821	2,707	2,707	2,707	2,633	0	0
21	21	21	21	0	0	0	0	0
6,215	6,215	6,215	6,215	6,215	6,215	6,029	0	0
0	0	0	0	0	0	0	0	0
14	14	14	14	14	0	0	0	0
0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0
26	26	26	26	26	26	26	26	26
0	0	0	0	0	0	0	0	0
10,760	**10,248**	**10,248**	**10,134**	**10,110**	**10,096**	**9,607**	**944**	**944**
12,571	**12,059**	**11,750**	**11,636**	**11,612**	**10,286**	**9,765**	**1,103**	**944**

Gross								
Annual Energy Savings (MWh)								
2017	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
0	0	0	0	0	0	0	0	0
11,574	11,574	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0
11,574	**11,574**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
0	0	0	0	0	0	0	0	0
50,864	50,864	50,864	50,864	50,864	5,050	5,050	5,050	0
0	0	0	0	0	0	0	0	0
3,206	3,206	3,206	3,206	3,206	1,807	673	673	0
0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0
4,254	4,254	4,254	4,254	0	0	0	0	0
0	0	0	0	0	0	0	0	0
2,300	2,300	2,300	2,300	2,300	2,300	2,300	2,300	2,300
0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0
8,607	8,607	8,607	8,607	8,607	8,607	8,607	8,607	8,607
69,231	**69,231**	**69,231**	**69,231**	**64,977**	**17,763**	**16,629**	**16,629**	**10,907**
0	0	0	0	0	0	0	0	0
40,725	40,725	40,725	40,725	40,725	40,725	32,497	32,497	32,497
0	0	0	0	0	0	0	0	0
9,517	7,211	7,211	7,211	6,380	6,084	5,784	5,784	5,784
118,827	100,820	100,820	96,741	96,741	96,741	94,100	0	0
757	757	757	757	0	0	0	0	0
89,372	89,372	89,372	89,372	89,372	89,372	86,690	0	0
67,575	67,535	67,535	66,407	66,407	66,407	65,230	11,748	11,748
410	410	410	410	410	0	0	0	0
2,802	2,802	2,802	2,802	2,802	2,802	68	0	0
0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0
2,118	2,118	2,118	2,118	2,118	2,118	2,118	2,118	2,118
27,498	27,498	27,498	27,498	27,498	27,498	27,498	27,498	27,498
359,600	**339,246**	**339,246**	**334,040**	**332,452**	**331,746**	**313,985**	**79,645**	**79,645**
440,405	**420,052**	**408,477**	**403,271**	**397,429**	**349,509**	**330,614**	**96,274**	**90,551**

2026	2027	2028	2029	2030	2031	2032
0	0	0	0	0	0	0
0	0	0	0	0	0	0
0	0	0	0	0	0	0
0	0	0	0	0	0	0
0	0	0	0	0	0	0
0	**0**	**0**	**0**	**0**	**0**	**0**
0	0	0	0	0	0	0
0	0	0	0	0	0	0
0	0	0	0	0	0	0
0	0	0	0	0	0	0
0	0	0	0	0	0	0
0	0	0	0	0	0	0
0	0	0	0	0	0	0
0	0	0	0	0	0	0
0	0	0	0	0	0	0
0	0	0	0	0	0	0
0	0	0	0	0	0	0
0	0	0	0	0	0	0
0	0	0	0	0	0	0
0	0	0	0	0	0	0
0	**0**	**0**	**0**	**0**	**0**	**0**
0	0	0	0	0	0	0
0	0	0	0	0	0	0
0	0	0	0	0	0	0
20	20	0	0	0	0	0
0	0	0	0	0	0	0
0	0	0	0	0	0	0
0	0	0	0	0	0	0
0	0	0	0	0	0	0
0	0	0	0	0	0	0
0	0	0	0	0	0	0
0	0	0	0	0	0	0
0	0	0	0	0	0	0
0	0	0	0	0	0	0
0	0	0	0	0	0	0
0	0	0	0	0	0	0
26	26	0	0	0	0	0
0	0	0	0	0	0	0
45	**45**	**0**	**0**	**0**	**0**	**0**
45	**45**	**0**	**0**	**0**	**0**	**0**

2026	2027	2028	2029	2030	2031	2032
0	0	0	0	0	0	0
0	0	0	0	0	0	0
0	0	0	0	0	0	0
0	0	0	0	0	0	0
0	0	0	0	0	0	0
0	**0**	**0**	**0**	**0**	**0**	**0**
0	0	0	0	0	0	0
0	0	0	0	0	0	0
0	0	0	0	0	0	0
0	0	0	0	0	0	0
0	0	0	0	0	0	0
0	0	0	0	0	0	0
0	0	0	0	0	0	0
0	0	0	0	0	0	0
0	0	0	0	0	0	0
0	0	0	0	0	0	0
0	0	0	0	0	0	0
0	0	0	0	0	0	0
0	0	0	0	0	0	0
8,607	0	0	0	0	0	0
8,607	**0**	**0**	**0**	**0**	**0**	**0**
0	0	0	0	0	0	0
0	0	0	0	0	0	0
0	0	0	0	0	0	0
5,784	5,784	0	0	0	0	0
0	0	0	0	0	0	0
0	0	0	0	0	0	0
0	0	0	0	0	0	0
11,748	11,748	0	0	0	0	0
0	0	0	0	0	0	0
0	0	0	0	0	0	0
0	0	0	0	0	0	0
0	0	0	0	0	0	0
0	0	0	0	0	0	0
0	0	0	0	0	0	0
0	0	0	0	0	0	0
2,118	2,118	0	0	0	0	0
27,498	27,498	0	0	0	0	0
47,148	**47,148**	**0**	**0**	**0**	**0**	**0**
55,754	**47,148**	**0**	**0**	**0**	**0**	**0**

OPA Conservation & Demand Management Programs
Measure Results

For: Hydro One Brampton Networks Inc.

#	Initiative Name	Program Name	Program Year
2006			
1	2006 Every Kilowatt Counts (spring)	Consumer	2006
1	2006 Every Kilowatt Counts (spring)	Consumer	2006
1	2006 Every Kilowatt Counts (spring)	Consumer	2006
1	2006 Every Kilowatt Counts (spring)	Consumer	2006
2	2006 Cool Savings Rebate Program	Consumer	2006
2	2006 Cool Savings Rebate Program	Consumer	2006
2	2006 Cool Savings Rebate Program	Consumer	2006
3	2006 Secondary Fridge Retirement Pilot	Consumer	2006
3	2006 Secondary Fridge Retirement Pilot	Consumer	2006
4	2006 Every Kilowatt Counts (fall)	Consumer	2006
4	2006 Every Kilowatt Counts (fall)	Consumer	2006
4	2006 Every Kilowatt Counts (fall)	Consumer	2006
4	2006 Every Kilowatt Counts (fall)	Consumer	2006
4	2006 Every Kilowatt Counts (fall)	Consumer	2006
4	2006 Every Kilowatt Counts (fall)	Consumer	2006
6	2006 Demand Response 1	Industrial, Business	2006
2007			
7	2007 Great Refrigerator Roundup	Consumer	2007
7	2007 Great Refrigerator Roundup	Consumer	2007
7	2007 Great Refrigerator Roundup	Consumer	2007
7	2007 Great Refrigerator Roundup	Consumer	2007
7	2007 Great Refrigerator Roundup	Consumer	2007
8	2007 Cool Savings Rebate	Consumer	2007
8	2007 Cool Savings Rebate	Consumer	2007
8	2007 Cool Savings Rebate	Consumer	2007
8	2007 Cool Savings Rebate	Consumer	2007
9	2007 Aboriginal – Pilot	Consumer	2007
10	2007 Every Kilowatt Counts	Consumer	2007
10	2007 Every Kilowatt Counts	Consumer	2007
10	2007 Every Kilowatt Counts	Consumer	2007
10	2007 Every Kilowatt Counts	Consumer	2007
10	2007 Every Kilowatt Counts	Consumer	2007
10	2007 Every Kilowatt Counts	Consumer	2007
10	2007 Every Kilowatt Counts	Consumer	2007
10	2007 Every Kilowatt Counts	Consumer	2007
10	2007 Every Kilowatt Counts	Consumer	2007
10	2007 Every Kilowatt Counts	Consumer	2007
10	2007 Every Kilowatt Counts	Consumer	2007

10	2007 Every Kilowatt Counts	Consumer	2007
10	2007 Every Kilowatt Counts	Consumer	2007
10	2007 Every Kilowatt Counts	Consumer	2007
11	2007 peaksaver®	Consumer, Business	2007
11	2007 peaksaver®	Consumer, Business	2007
11	2007 peaksaver®	Consumer, Business	2007
11	2007 peaksaver®	Consumer, Business	2007
11	2007 peaksaver®	Consumer, Business	2007
11	2007 peaksaver®	Consumer, Business	2007
12	2007 Summer Savings	Consumer	2007
13	2007 Affordable Housing – Pilot	Consumer	2007
13	2007 Affordable Housing – Pilot	Consumer	2007
13	2007 Affordable Housing – Pilot	Consumer	2007
13	2007 Affordable Housing – Pilot	Consumer	2007
13	2007 Affordable Housing – Pilot	Consumer	2007
13	2007 Affordable Housing – Pilot	Consumer	2007
13	2007 Affordable Housing – Pilot	Consumer	2007
13	2007 Affordable Housing – Pilot	Consumer	2007
13	2007 Affordable Housing – Pilot	Consumer	2007
13	2007 Affordable Housing – Pilot	Consumer	2007
13	2007 Affordable Housing – Pilot	Consumer	2007
13	2007 Affordable Housing – Pilot	Consumer	2007
13	2007 Affordable Housing – Pilot	Consumer	2007
13	2007 Affordable Housing – Pilot	Consumer	2007
13	2007 Affordable Housing – Pilot	Consumer	2007
13	2007 Affordable Housing – Pilot	Consumer	2007
13	2007 Affordable Housing – Pilot	Consumer	2007
13	2007 Affordable Housing – Pilot	Consumer	2007
13	2007 Affordable Housing – Pilot	Consumer	2007
13	2007 Affordable Housing – Pilot	Consumer	2007
13	2007 Affordable Housing – Pilot	Consumer	2007
13	2007 Affordable Housing – Pilot	Consumer	2007
13	2007 Affordable Housing – Pilot	Consumer	2007
13	2007 Affordable Housing – Pilot	Consumer	2007
13	2007 Affordable Housing – Pilot	Consumer	2007
13	2007 Affordable Housing – Pilot	Consumer	2007
13	2007 Affordable Housing – Pilot	Consumer	2007
13	2007 Affordable Housing – Pilot	Consumer	2007
13	2007 Affordable Housing – Pilot	Consumer	2007
13	2007 Affordable Housing – Pilot	Consumer	2007
14	2007 Social Housing – Pilot	Consumer	2007
15	2007 Energy Efficiency Assistance for House	Consumer	2007
16	2007 Toronto Comprehensive	Business	2007
16	2007 Toronto Comprehensive	Business	2007
16	2007 Toronto Comprehensive	Business	2007
17	2007 Electricity Retrofit Incentive Program	Business	2007
18	2007 Demand Response 1	Industrial, Business	2007
19	2007 Other Demand Response	Industrial, Business	2007
19	2007 Other Demand Response	Industrial, Business	2007
20	2007 Renewable Energy Standard Offer	Consumer, Business, Industrial, Low-Income	2007
20	2007 Renewable Energy Standard Offer	Consumer, Business, Industrial, Low-Income	2007
20	2007 Renewable Energy Standard Offer	Consumer, Business, Industrial, Low-Income	2007

20	2007 Renewable Energy Standard Offer	Consumer, Business, Industrial, Low-Income	2007

2008			
21	2008 Great Refrigerator Roundup	Consumer	2008
21	2008 Great Refrigerator Roundup	Consumer	2008
21	2008 Great Refrigerator Roundup	Consumer	2008
22	2008 Cool Savings Rebate	Consumer	2008
22	2008 Cool Savings Rebate	Consumer	2008
22	2008 Cool Savings Rebate	Consumer	2008
22	2008 Cool Savings Rebate	Consumer	2008
22	2008 Cool Savings Rebate	Consumer	2008
22	2008 Cool Savings Rebate	Consumer	2008
22	2008 Cool Savings Rebate	Consumer	2008
23	2008 Aboriginal	Consumer	2008
24	2008 Summer Sweepstakes	Consumer	2008
25	2008 Every Kilowatt Counts Power Savings I	Consumer	2008
25	2008 Every Kilowatt Counts Power Savings I	Consumer	2008
25	2008 Every Kilowatt Counts Power Savings I	Consumer	2008
25	2008 Every Kilowatt Counts Power Savings I	Consumer	2008
25	2008 Every Kilowatt Counts Power Savings I	Consumer	2008
25	2008 Every Kilowatt Counts Power Savings I	Consumer	2008
25	2008 Every Kilowatt Counts Power Savings I	Consumer	2008
25	2008 Every Kilowatt Counts Power Savings I	Consumer	2008
25	2008 Every Kilowatt Counts Power Savings I	Consumer	2008
25	2008 Every Kilowatt Counts Power Savings I	Consumer	2008
25	2008 Every Kilowatt Counts Power Savings I	Consumer	2008
25	2008 Every Kilowatt Counts Power Savings I	Consumer	2008
25	2008 Every Kilowatt Counts Power Savings I	Consumer	2008
25	2008 Every Kilowatt Counts Power Savings I	Consumer	2008
25	2008 Every Kilowatt Counts Power Savings I	Consumer	2008
25	2008 Every Kilowatt Counts Power Savings I	Consumer	2008
25	2008 Every Kilowatt Counts Power Savings I	Consumer	2008
25	2008 Every Kilowatt Counts Power Savings I	Consumer	2008
25	2008 Every Kilowatt Counts Power Savings I	Consumer	2008
25	2008 Every Kilowatt Counts Power Savings I	Consumer	2008
25	2008 Every Kilowatt Counts Power Savings I	Consumer	2008
25	2008 Every Kilowatt Counts Power Savings I	Consumer	2008
26	2008 peaksaver®	Consumer, Business	2008
26	2008 peaksaver®	Consumer, Business	2008
26	2008 peaksaver®	Consumer, Business	2008
26	2008 peaksaver®	Consumer, Business	2008
26	2008 peaksaver®	Consumer, Business	2008
26	2008 peaksaver®	Consumer, Business	2008
27	2008 Electricity Retrofit Incentive	Business	2008
27	2008 Electricity Retrofit Incentive	Business	2008
27	2008 Electricity Retrofit Incentive	Business	2008
27	2008 Electricity Retrofit Incentive	Business	2008
27	2008 Electricity Retrofit Incentive	Business	2008
27	2008 Electricity Retrofit Incentive	Business	2008
27	2008 Electricity Retrofit Incentive	Business	2008
27	2008 Electricity Retrofit Incentive	Business	2008
27	2008 Electricity Retrofit Incentive	Business	2008

27	2008 Electricity Retrofit Incentive	Business	2008
27	2008 Electricity Retrofit Incentive	Business	2008
27	2008 Electricity Retrofit Incentive	Business	2008
27	2008 Electricity Retrofit Incentive	Business	2008
27	2008 Electricity Retrofit Incentive	Business	2008
27	2008 Electricity Retrofit Incentive	Business	2008
27	2008 Electricity Retrofit Incentive	Business	2008
27	2008 Electricity Retrofit Incentive	Business	2008
27	2008 Electricity Retrofit Incentive	Business	2008
27	2008 Electricity Retrofit Incentive	Business	2008
27	2008 Electricity Retrofit Incentive	Business	2008
27	2008 Electricity Retrofit Incentive	Business	2008
27	2008 Electricity Retrofit Incentive	Business	2008
27	2008 Electricity Retrofit Incentive	Business	2008
27	2008 Electricity Retrofit Incentive	Business	2008
27	2008 Electricity Retrofit Incentive	Business	2008
27	2008 Electricity Retrofit Incentive	Business	2008
27	2008 Electricity Retrofit Incentive	Business	2008
27	2008 Electricity Retrofit Incentive	Business	2008
27	2008 Electricity Retrofit Incentive	Business	2008
27	2008 Electricity Retrofit Incentive	Business	2008
27	2008 Electricity Retrofit Incentive	Business	2008
27	2008 Electricity Retrofit Incentive	Business	2008
27	2008 Electricity Retrofit Incentive	Business	2008
27	2008 Electricity Retrofit Incentive	Business	2008
27	2008 Electricity Retrofit Incentive	Business	2008
27	2008 Electricity Retrofit Incentive	Business	2008
27	2008 Electricity Retrofit Incentive	Business	2008
27	2008 Electricity Retrofit Incentive	Business	2008
27	2008 Electricity Retrofit Incentive	Business	2008
27	2008 Electricity Retrofit Incentive	Business	2008
27	2008 Electricity Retrofit Incentive	Business	2008
27	2008 Electricity Retrofit Incentive	Business	2008
27	2008 Electricity Retrofit Incentive	Business	2008
27	2008 Electricity Retrofit Incentive	Business	2008
27	2008 Electricity Retrofit Incentive	Business	2008
27	2008 Electricity Retrofit Incentive	Business	2008
27	2008 Electricity Retrofit Incentive	Business	2008
27	2008 Electricity Retrofit Incentive	Business	2008
27	2008 Electricity Retrofit Incentive	Business	2008
27	2008 Electricity Retrofit Incentive	Business	2008
27	2008 Electricity Retrofit Incentive	Business	2008
27	2008 Electricity Retrofit Incentive	Business	2008
27	2008 Electricity Retrofit Incentive	Business	2008
27	2008 Electricity Retrofit Incentive	Business	2008
27	2008 Electricity Retrofit Incentive	Business	2008
27	2008 Electricity Retrofit Incentive	Business	2008
27	2008 Electricity Retrofit Incentive	Business	2008
27	2008 Electricity Retrofit Incentive	Business	2008
27	2008 Electricity Retrofit Incentive	Business	2008
27	2008 Electricity Retrofit Incentive	Business	2008
27	2008 Electricity Retrofit Incentive	Business	2008

27	2008 Electricity Retrofit Incentive	Business	2008
27	2008 Electricity Retrofit Incentive	Business	2008
27	2008 Electricity Retrofit Incentive	Business	2008
27	2008 Electricity Retrofit Incentive	Business	2008
27	2008 Electricity Retrofit Incentive	Business	2008
27	2008 Electricity Retrofit Incentive	Business	2008
27	2008 Electricity Retrofit Incentive	Business	2008
27	2008 Electricity Retrofit Incentive	Business	2008
27	2008 Electricity Retrofit Incentive	Business	2008
27	2008 Electricity Retrofit Incentive	Business	2008
27	2008 Electricity Retrofit Incentive	Business	2008
27	2008 Electricity Retrofit Incentive	Business	2008
27	2008 Electricity Retrofit Incentive	Business	2008
27	2008 Electricity Retrofit Incentive	Business	2008
27	2008 Electricity Retrofit Incentive	Business	2008
27	2008 Electricity Retrofit Incentive	Business	2008
27	2008 Electricity Retrofit Incentive	Business	2008
27	2008 Electricity Retrofit Incentive	Business	2008
27	2008 Electricity Retrofit Incentive	Business	2008
27	2008 Electricity Retrofit Incentive	Business	2008
27	2008 Electricity Retrofit Incentive	Business	2008
27	2008 Electricity Retrofit Incentive	Business	2008
27	2008 Electricity Retrofit Incentive	Business	2008
27	2008 Electricity Retrofit Incentive	Business	2008
27	2008 Electricity Retrofit Incentive	Business	2008
27	2008 Electricity Retrofit Incentive	Business	2008
27	2008 Electricity Retrofit Incentive	Business	2008
27	2008 Electricity Retrofit Incentive	Business	2008
27	2008 Electricity Retrofit Incentive	Business	2008
27	2008 Electricity Retrofit Incentive	Business	2008
27	2008 Electricity Retrofit Incentive	Business	2008
27	2008 Electricity Retrofit Incentive	Business	2008
27	2008 Electricity Retrofit Incentive	Business	2008
28	2008 Toronto Comprehensive	Business	2008
28	2008 Toronto Comprehensive	Business	2008
28	2008 Toronto Comprehensive	Business	2008
29	2008 High Performance New Construction	Business	2008
30	2008 Power Savings Blitz	Business	2008
30	2008 Power Savings Blitz	Business	2008
30	2008 Power Savings Blitz	Business	2008
30	2008 Power Savings Blitz	Business	2008
30	2008 Power Savings Blitz	Business	2008
30	2008 Power Savings Blitz	Business	2008
30	2008 Power Savings Blitz	Business	2008
30	2008 Power Savings Blitz	Business	2008
31	2008 Chiller Plant Re-Commissioning	Business	2008
31	2008 Chiller Plant Re-Commissioning	Business	2008
31	2008 Chiller Plant Re-Commissioning	Business	2008
31	2008 Chiller Plant Re-Commissioning	Business	2008
31	2008 Chiller Plant Re-Commissioning	Business	2008
31	2008 Chiller Plant Re-Commissioning	Business	2008
31	2008 Chiller Plant Re-Commissioning	Business	2008

32	2008 Demand Response 1	Industrial, Business	2008
33	2008 Demand Response 3	Industrial, Business	2008
34	2008 Other Demand Response	Industrial, Business	2008
34	2008 Other Demand Response	Industrial, Business	2008
35	2008 LDC Custom	Consumer, Business, Industrial, Low-Income	2008
36	2008 Renewable Energy Standard Offer	Consumer, Business, Industrial, Low-Income	2008
36	2008 Renewable Energy Standard Offer	Consumer, Business, Industrial, Low-Income	2008
36	2008 Renewable Energy Standard Offer	Consumer, Business, Industrial, Low-Income	2008
36	2008 Renewable Energy Standard Offer	Consumer, Business, Industrial, Low-Income	2008
37	2008 Other Customer Based Generation	Consumer, Business, Industrial, Low-Income	2008

Results Status	#	Measure Name	Unit Savings Assumpt: Summer Peak Demand Savings per Unit (kW)	Annual Energy Savings per Unit (kWh)
Final	1	Energy Star® Compact Fluorescent Light Bulb	0.00	104
Final	2	Electric Timers	0.00	183
Final	3	Programmable Thermostats	0.05	216
Final	4	Energy Star® Ceiling Fans	0.01	141
Final	1	Energy Star® Air Conditioner	0.36	351
Final	2	Programmable Thermostats	0.16	159
Final	3	Air Conditioner Tune-Up	0.04	369
Final	1	Refrigerator Retirement	0.27	1,200
Final	2	Freezer Retirement	0.20	900
Final	1	Energy Star® Compact Fluorescent Light Bulb	0.00	104
Final	2	Seasonal Light Emitting Diode Light String	0.00	31
Final	3	Programmable Thermostats	0.12	522
Final	4	Dimmers	0.00	139
Final	5	Indoor Motion Sensors	0.00	209
Final	6	Programmable Basebaord Thermostats	0.00	1,466
Final	1	Voluntary Load Shedding Project	Custom	Custom
Final	1	Refrigerator	0.07	745
Final	2	Freezer	0.07	515
Final	3	Small Refrigerator	0.05	490
Final	4	Small Freezer	0.04	339
Final	5	Window Air Conditioner	0.56	240
Final	1	ENERGY STAR® Central Air Conditioner	0.17	152
Final	2	Programmable Thermostat	0.03	55
Final	3	Furnace with Electronically Commutated Motor	0.49	832
Final	4	Central Air Conditioning Tune Up	0.26	235
Final	1	Consumer Retrofit Kit	0.04	900
Final	1	15 W CFL	0.00	43
Final	2	20 W+ CFLs	0.00	62
Final	3	Project Porchlight CFLs	0.00	43
Final	4	Energy Star Ceiling Fan	0.00	90
Final	5	Furnace Filter	0.01	38
Final	6	Solar Lights	0.00	33
Final	7	Outdoor Motion Sensor	0.00	160
Final	8	Dimmer Switch	0.00	24
Final	9	Energy Star Light Fixtures	0.01	123
Final	10	SLEDs	0.00	14
Final	11	T8	0.00	37

Final	12	Programmable Thermostat	0.00	75
Final	13	Power Bar with Timer	0.01	72
Final	14	Lighting Control Devices	0.02	72
Final	1	Residential Programmable Thermostat	0.63	0
Final	2	Residential Air Conditioner Switch	0.63	0
Final	3	Residential Water Heater Switch	0.30	0
Final	4	Commercial Programmable Thermostat	4.00	0
Final	5	Commercial Air Conditioner Switch	4.00	0
Final	6	Commercial Water Heater Switch	0.30	0
Final	1	Household	0.44	787
Final	1	1 - T8 32W w/EL ballast	0.01	30
Final	2	2 - T8 32W w/EL ballast	0.02	46
Final	3	Air-source Heat Pump - Split	6.08	4,437
Final	4	Automated Controls for HVAC	0.00	18,565
Final	5	Boiler	0.01	17
Final	6	Ceiling Fan (common area)	0.00	7
Final	7	Ceiling Fan (in-suite)	0.00	7
Final	8	Central Air Conditioning System - Single	1.07	807
Final	9	Central Air Conditioning System - Split	1.94	1,456
Final	10	CFL Screw-In 15W - in suite	0.01	180
Final	11	CFL Screw-In 25W - in suite	0.01	300
Final	12	Dimmer Switch	0.00	139
Final	13	Energy Star Clotheswasher	0.03	287
Final	14	Energy Star Dishwasher	0.01	136
Final	15	Energy Star Refrigerator	0.01	69
Final	16	Flood Light, 26W Fluorescent Fixture	0.01	128
Final	17	Front Loading Washing Machine	0.11	1,108
Final	18	Furnace	0.02	25
Final	19	Furnace with DC Motor	0.03	45
Final	20	Ground-source Heat Pump	4.71	3,545
Final	21	High Pressure Sodium	0.09	749
Final	22	Motion Detector	0.00	209
Final	23	Occupancy Sensors	0.00	209
Final	24	Other CFL Screw-in Light (please specify)	0.01	383
Final	25	Other Exterior Lighting (please specify)	0.01	160
Final	26	Other Parking Garage Lighting (please specify)	0.05	442
Final	27	Photo Sensors	0.00	292
Final	28	Programmable Thermostat	0.01	631
Final	29	Timer - Outdoor Light	0.00	292
Final	30	Ventilating Fan (in-suite)	0.00	12
Final	1	Custom Retrofit Projects	Custom	Custom
Final	1	Custom Retrofit Projects	Custom	Custom
Final	1	City of Toronto - Better Building Partnership Project	Custom	Custom
Final	2	Toronto Hydro - Business Incentive Program Project	Custom	Custom
Final	3	Building Owners & Managers Association - Toronto Pro	Custom	Custom
Final	1	Custom Retrofit Projects	Custom	Custom
Final	1	Voluntary Load Shedding Project	Custom	Custom
Final	1	Loblaw Contract	Custom	Custom
Final	2	Rodan Contract	Custom	Custom
Final	1	Hydro	Custom	Custom
Final	2	Wind	Custom	Custom
Final	3	Solar Photo-Voltaic	Custom	Custom

Final	4	Bio-Energy	Custom	Custom
Final	1	Refrigerator	0.08	775
Final	2	Freezer	0.08	740
Final	3	Room Air Conditioner	0.20	197
Final	1	2007 Efficient Furnance with Electronically Commutable	0.50	837
Final	2	2007 ENERGYSTAR® Central Air Conditioner	0.17	155
Final	3	2007 Programable Thermostat	0.03	54
Final	4	2007 Central Air Conditioner Tune-ups	0.26	235
Final	5	2008 Efficient Furnance with Electronically Commutable	0.49	819
Final	6	2008 ENERGYSTAR® Central Air Conditioner	0.14	125
Final	7	2008 Programable Thermostat	0.03	54
Final	1	Building Retrofits	1.60	2,820
Final	1	Households	0.20	768
Final	1	Air Conditioner/Furnace Filters	0.02	38
Final	2	Energy Star® Qualified Compact Fluorescent Floods (Ir	0.00	88
Final	3	Energy Star® Qualified Light Fixtures	0.00	133
Final	4	Heavy Duty Timers	0.02	301
Final	5	T8 Fluorescent Fixtures	0.00	37
Final	6	ENERGY STAR Decorative CFLs	0.00	30
Final	7	ENERGY STAR Dimmable CFLs	0.00	98
Final	8	Power Bars with Timers	0.00	53
Final	9	Programmable Thermostats - Baseboard	0.00	64
Final	10	Car block heater timer	n/a	n/a
Final	11	Energy Star® Qualified Compact Fluorescent Light Bulb	0.00	53
Final	12	Lighting Control Devices	0.00	102
Final	13	Awnings	0.00	0
Final	14	Window Films	0.00	0
Final	15	Electric Water Heater Blankets	0.00	0
Final	16	Pipe Wrap	0.00	38
Final	17	Low-Flow Toilets	0.00	0
Final	18	Keep Cool – Dehumidifier	0.29	500
Final	19	Keep Cool – Room Air Conditioner	0.14	141
Final	20	Rewards for Recycling – Dehumidifier	0.29	500
Final	21	Rewards for Recycling – Room Air Conditioner	0.14	141
Final	22	Rewards for Recycling - Halogen Lamp	0.01	275
Final	1	Residential Programmable Thermostat	0.87	17
Final	2	Residential Air Conditioner Switch	0.87	17
Final	3	Residential Water Heater Switch	0.30	6
Final	4	Commercial Programmable Thermostat	3.70	74
Final	5	Commercial Air Conditioner Switch	3.70	74
Final	6	Commercial Water Heater Switch	1.85	37
Final	1	Agribusiness ENERGY STAR® Rated Exit Signs, All siz	n/a	n/a
Final	2	Agribusiness ENERGY STAR® Rated CFLs, Screw in.	n/a	n/a
Final	3	Agribusiness ENERGY STAR® Rated CFLs, Hard wired	n/a	n/a
Final	4	Agribusiness Standard Performance T8, Single lamp sta	n/a	n/a
Final	5	Agribusiness Standard Performance T8, Double lamp s	n/a	n/a
Final	6	Agribusiness Standard Performance T8, Triple lamp sta	n/a	n/a
Final	7	Agribusiness Standard Performance T8, Quadruple lam	n/a	n/a
Final	8	Agribusiness High Performance T8 (Consortium for Ene	n/a	n/a
Final	9	Agribusiness High Performance T8 (Consortium for Ene	n/a	n/a

Final	10	Agribusiness High Performance T8 (Consortium for Ene	n/a	n/a
Final	11	Agribusiness High Performance T8 (Consortium for Ene	n/a	n/a
Final	12	Agribusiness T5 Fixtures, T5 fixture with 1, 2, or 3 lamp	n/a	n/a
Final	13	Agribusiness T5 Fixtures, High Bay T5. Maximum 6 lan	n/a	n/a
Final	14	Agribusiness Metal Halide, 320 W Ceramic pulse start	n/a	n/a
Final	15	Agribusiness Occupancy Sensors, Switch plate mounte	n/a	n/a
Final	16	Agribusiness Occupancy Sensors, Ceiling mounted occ	n/a	n/a
Final	17	Agribusiness Creep Heat Pads, up to 100W maximum	n/a	n/a
Final	18	Agribusiness Creep Heat Pads, up to 200W maximum	n/a	n/a
Final	19	Agribusiness High Temperature Cutout Thermostat	n/a	n/a
Final	20	Agribusiness Creep Heat Controller	n/a	n/a
Final	21	Agribusiness Energy Efficient Ventilation Exhaust Fans	n/a	n/a
Final	22	Agribusiness Low Energy Livestock Waterers	n/a	n/a
Final	23	Agribusiness Photocell and Timer for Lighting Control	n/a	n/a
Final	24	Lighting System Exit Signs, 5 W or less	n/a	n/a
Final	25	Lighting System ENERGY STAR® Rated CFLs, Screw	n/a	n/a
Final	26	Lighting System ENERGY STAR® Rated CFLs, Hard w	n/a	n/a
Final	27	Lighting System Standard Performance T8, Single lamp	n/a	n/a
Final	28	Lighting System Standard Performance T8, Double lam	n/a	n/a
Final	29	Lighting System Standard Performance T8, Triple lamp	n/a	n/a
Final	30	Lighting System Standard Performance T8, Quadruple	n/a	n/a
Final	31	Lighting System High Performance T8 (Consortium for	n/a	n/a
Final	32	Lighting System High Performance T8 (Consortium for	n/a	n/a
Final	33	Lighting System High Performance T8 (Consortium for	n/a	n/a
Final	34	Lighting System High Performance T8 (Consortium for	n/a	n/a
Final	35	Lighting System T5 Fixtures, T5 fixture with 1, 2, or 3 la	n/a	n/a
Final	36	Lighting System T5 Fixtures, High Bay T5. Maximum 6	n/a	n/a
Final	37	Lighting System Metal Halide, 320 W Ceramic pulse sta	n/a	n/a
Final	38	Lighting System Occupancy Sensors, Switch plate mou	n/a	n/a
Final	39	Lighting System Occupancy Sensors, Ceiling mounted	n/a	n/a
Final	40	Motor Open Drip-Proof (ODP), 1 HP	n/a	n/a
Final	41	Motor Open Drip-Proof (ODP), 1.5 HP	n/a	n/a
Final	42	Motor Open Drip-Proof (ODP), 2 HP	n/a	n/a
Final	43	Motor Open Drip-Proof (ODP), 3 HP	n/a	n/a
Final	44	Motor Open Drip-Proof (ODP), 5 HP	n/a	n/a
Final	45	Motor Open Drip-Proof (ODP), 7.5 HP	n/a	n/a
Final	46	Motor Open Drip-Proof (ODP), 10 HP	n/a	n/a
Final	47	Motor Open Drip-Proof (ODP), 15 HP	n/a	n/a
Final	48	Motor Open Drip-Proof (ODP), 20 HP	n/a	n/a
Final	49	Motor Open Drip-Proof (ODP), 25 HP	n/a	n/a
Final	50	Motor Open Drip-Proof (ODP), 30 HP	n/a	n/a
Final	51	Motor Open Drip-Proof (ODP), 40 HP	n/a	n/a
Final	52	Motor Open Drip-Proof (ODP), 50 HP	n/a	n/a
Final	53	Motor Open Drip-Proof (ODP), 60 HP	n/a	n/a
Final	54	Motor Open Drip-Proof (ODP), 75 HP	n/a	n/a
Final	55	Motor Open Drip-Proof (ODP), 100 HP	n/a	n/a
Final	56	Motor Open Drip-Proof (ODP), 125 HP	n/a	n/a
Final	57	Motor Open Drip-Proof (ODP), 150 HP	n/a	n/a
Final	58	Motor Open Drip-Proof (ODP), 200 HP	n/a	n/a
Final	59	Motor Totally Enclosed Fan-Cooled (TEFC), 1 HP	n/a	n/a
Final	60	Motor Totally Enclosed Fan-Cooled (TEFC), 1.5 HP	n/a	n/a
Final	61	Motor Totally Enclosed Fan-Cooled (TEFC), 2 HP	n/a	n/a

Final	62	Motor Totally Enclosed Fan-Cooled (TEFC), 3 HP	n/a	n/a
Final	63	Motor Totally Enclosed Fan-Cooled (TEFC), 5 HP	n/a	n/a
Final	64	Motor Totally Enclosed Fan-Cooled (TEFC), 7.5 HP	n/a	n/a
Final	65	Motor Totally Enclosed Fan-Cooled (TEFC), 10 HP	n/a	n/a
Final	66	Motor Totally Enclosed Fan-Cooled (TEFC), 15 HP	n/a	n/a
Final	67	Motor Totally Enclosed Fan-Cooled (TEFC), 20 HP	n/a	n/a
Final	68	Motor Totally Enclosed Fan-Cooled (TEFC), 25 HP	n/a	n/a
Final	69	Motor Totally Enclosed Fan-Cooled (TEFC), 30 HP	n/a	n/a
Final	70	Motor Totally Enclosed Fan-Cooled (TEFC), 40 HP	n/a	n/a
Final	71	Motor Totally Enclosed Fan-Cooled (TEFC), 50 HP	n/a	n/a
Final	72	Motor Totally Enclosed Fan-Cooled (TEFC), 60 HP	n/a	n/a
Final	73	Motor Totally Enclosed Fan-Cooled (TEFC), 75 HP	n/a	n/a
Final	74	Motor Totally Enclosed Fan-Cooled (TEFC), 100 HP	n/a	n/a
Final	75	Motor Totally Enclosed Fan-Cooled (TEFC), 125 HP	n/a	n/a
Final	76	Motor Totally Enclosed Fan-Cooled (TEFC), 150 HP	n/a	n/a
Final	77	Motor Totally Enclosed Fan-Cooled (TEFC), 200 HP	n/a	n/a
Final	78	Transformer Size 15	n/a	n/a
Final	79	Transformer Size 30	n/a	n/a
Final	80	Transformer Size 45	n/a	n/a
Final	81	Transformer Size 75	n/a	n/a
Final	82	Transformer Size 112.5	n/a	n/a
Final	83	Transformer Size 150	n/a	n/a
Final	84	Transformer Size 225	n/a	n/a
Final	85	Transformer Size 300	n/a	n/a
Final	86	Transformer Size 500	n/a	n/a
Final	87	Transformer Size 750	n/a	n/a
Final	88	Transformer Size 1000	n/a	n/a
Final	89	Unitary AC Single Phase <= 5.4 Tons	n/a	n/a
Final	90	Unitary AC 3 Phase <= 5.4 Tons	n/a	n/a
Final	91	Unitary AC >5.4 & <= 11.25 tons	n/a	n/a
Final	92	Unitary AC >11.25 & <= 20 tons	n/a	n/a
Final	93	Unitary AC 25 tons	n/a	n/a
Final	94	Custom	n/a	n/a
Final	1	City of Toronto - Better Building Partnership Project	Custom	Custom
Final	2	Toronto Hydro - Business Incentive Program Project	Custom	Custom
Final	3	Building Owners & Managers Association - Toronto Pro	Custom	Custom
Final	1	Custom New Construction Project	Custom	Custom
Final	1	T8 Fixture With Electronic Balllast	0.02	151
Final	2	Energy Star® rated LED Exit Sign	0.03	237
Final	3	Energy Star® rated CLF	0.03	191
Final	4	Electric Water Heater Tank Wrap	0.05	436
Final	5	Electric Water Heater Pipe Insulation	0.03	277
Final	6	Aerator	0.03	310
Final	7	Halogen	1.96	14
Final	8	Other	0.00	0
Final	1	Mixed Use Facility	TBD	TBD
Final	2	University Campus	TBD	TBD
Final	3	Hospital	TBD	TBD
Final	4	Commercial Office Tower	TBD	TBD
Final	5	Industrial/Manufacturing Facility	TBD	TBD
Final	6	City Government Central Utilities Plant	TBD	TBD
Final	7	Hotel	TBD	TBD

Final	1	Voluntary Load Shedding Project	Custom	Custom
Final	1	Contractual Load Shedding Project	Custom	Custom
Final	1	Loblaw Contract	Custom	Custom
Final	2	Rodan Contract	Custom	Custom
Final	1	Hydro One Networks - Double Return	52,000.00	0
Final	1	Hydro	Custom	Custom
Final	2	Wind	Custom	Custom
Final	3	Solar Photo-Voltaic	Custom	Custom
Final	4	Bio-Energy	Custom	Custom
Final	1	Combined Heat & Power / By-Product	Custom	Custom

tions	Net-to-Gross Adjustments (%)					
Effective Useful Life (EUL)	Free Rider (#1)	Spill Over (#2)	Exclusions (#3)	Part Use (#4)	Other (#5)	Aggregate (#6)
4	90%	100%	100%	100%	100%	90%
20	90%	100%	100%	100%	100%	90%
15	90%	100%	100%	100%	100%	90%
20	90%	100%	100%	100%	100%	90%
14	90%	100%	100%	100%	100%	90%
18	90%	100%	100%	100%	100%	90%
8	90%	100%	100%	100%	100%	90%
6	90%	100%	100%	100%	100%	90%
6	90%	100%	100%	100%	100%	90%
4	90%	100%	100%	100%	100%	90%
30	90%	100%	100%	100%	100%	90%
18	90%	100%	100%	100%	100%	90%
10	90%	100%	100%	100%	100%	90%
20	90%	100%	100%	100%	100%	90%
18	90%	100%	100%	100%	100%	90%
3	100%	100%	100%	100%	100%	100%
9	48%	100%	100%	81%	100%	39%
8	50%	100%	100%	91%	100%	46%
9	38%	100%	100%	79%	100%	30%
8	38%	100%	100%	79%	100%	30%
5	43%	100%	100%	100%	100%	43%
18	52%	5%	100%	100%	100%	57%
15	46%	0%	60%	100%	100%	27%
15	54%	5%	100%	100%	100%	59%
5	42%	0%	38%	100%	100%	16%
4	100%	100%	100%	100%	100%	100%
8	78%	100%	100%	100%	100%	78%
8	78%	100%	100%	100%	100%	78%
8	76%	100%	100%	100%	100%	76%
10	55%	100%	100%	100%	100%	55%
1	55%	100%	100%	100%	100%	55%
5	13%	100%	100%	100%	100%	13%
10	55%	100%	100%	100%	100%	55%
10	55%	100%	100%	100%	100%	55%
16	55%	100%	100%	100%	100%	55%
5	49%	100%	100%	100%	100%	49%
18	77%	100%	100%	100%	100%	77%

15	55%	100%	100%	100%	100%	55%
10	77%	100%	100%	100%	100%	77%
10	55%	100%	100%	100%	100%	55%
12	90%	100%	100%	100%	100%	90%
12	90%	100%	100%	100%	100%	90%
12	90%	100%	100%	100%	100%	90%
12	90%	100%	100%	100%	100%	90%
12	90%	100%	100%	100%	100%	90%
12	90%	100%	100%	100%	100%	90%
2	12%	100%	100%	100%	100%	12%
14	100%	100%	100%	100%	100%	100%
14	100%	100%	100%	100%	100%	100%
14	100%	100%	100%	100%	100%	100%
14	100%	100%	100%	100%	100%	100%
14	100%	100%	100%	100%	100%	100%
14	100%	100%	100%	100%	100%	100%
14	100%	100%	100%	100%	100%	100%
14	100%	100%	100%	100%	100%	100%
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14	100%	100%	100%	100%	100%	100%
14	100%	100%	100%	100%	100%	100%
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14	100%	100%	100%	100%	100%	100%
14	100%	100%	100%	100%	100%	100%
14	100%	100%	100%	100%	100%	100%
14	100%	100%	100%	100%	100%	100%
14	100%	100%	100%	100%	100%	100%
14	100%	100%	100%	100%	100%	100%
14	100%	100%	100%	100%	100%	100%
14	100%	100%	100%	100%	100%	100%
14	100%	100%	100%	100%	100%	100%
14	100%	100%	100%	100%	100%	100%
14	100%	100%	100%	100%	100%	100%
14	100%	100%	100%	100%	100%	100%
14	100%	100%	100%	100%	100%	100%
14	100%	100%	100%	100%	100%	100%
14	100%	100%	100%	100%	100%	100%
14	100%	100%	100%	100%	100%	100%
14	100%	100%	100%	100%	100%	100%
14	100%	100%	100%	100%	100%	100%
10	100%	100%	100%	100%	100%	100%
19	100%	100%	100%	100%	100%	100%
5	90%	100%	100%	100%	100%	90%
5	90%	100%	100%	100%	100%	90%
5	90%	100%	100%	100%	100%	90%
5	90%	100%	100%	100%	100%	90%
2	100%	100%	100%	100%	100%	100%
2	100%	100%	100%	100%	100%	100%
2	100%	100%	100%	100%	100%	100%
20	100%	100%	100%	100%	100%	100%
20	100%	100%	100%	100%	100%	100%
20	100%	100%	100%	100%	100%	100%

20	100%	100%	100%	100%	100%	100%
9	55%	100%	100%	100%	100%	55%
8	52%	100%	100%	100%	100%	52%
4.5	36%	100%	100%	100%	100%	36%
15	54%	100%	100%	100%	5%	100%
18	52%	100%	100%	100%	5%	100%
15	46%	100%	100%	100%	0%	60%
5	16%	100%	100%	100%	0%	100%
18	54%	100%	100%	100%	5%	100%
18	52%	100%	100%	100%	5%	100%
18	46%	100%	100%	100%	0%	60%
10	100%	100%	100%	100%	100%	100%
1	78%	100%	100%	100%	100%	78%
1	35%	100%	100%	100%	100%	100%
7	37%	100%	100%	100%	100%	100%
16	33%	100%	100%	100%	100%	100%
10	33%	100%	100%	100%	100%	100%
16	33%	100%	100%	100%	100%	100%
4	39%	100%	100%	100%	100%	100%
6	38%	100%	100%	100%	100%	100%
10	41%	100%	100%	100%	100%	100%
15	47%	100%	100%	100%	100%	100%
n/a	0%	100%	100%	100%	100%	100%
8	52%	100%	100%	100%	100%	100%
10	45%	100%	100%	100%	100%	100%
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n/a	0%	100%	100%	100%	100%	100%
6	47%	100%	100%	100%	100%	100%
n/a	0%	100%	100%	100%	100%	100%
12	35%	100%	100%	100%	100%	100%
9	42%	100%	100%	100%	100%	100%
12	44%	100%	100%	100%	100%	100%
9	44%	100%	100%	100%	100%	100%
16	48%	100%	100%	100%	100%	100%
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Custom	Custom	100%	100%	100%	100%	Custom
Custom	Custom	100%	100%	100%	100%	Custom
Custom	Custom	100%	100%	100%	100%	Custom
14	Custom	100%	100%	100%	100%	Custom
15	93%	100%	100%	100%	100%	93%
16	93%	100%	100%	100%	100%	93%
2	93%	100%	100%	100%	100%	93%
7	93%	100%	100%	100%	100%	93%
15	93%	100%	100%	100%	100%	93%
5	93%	100%	100%	100%	100%	93%
1	93%	100%	100%	100%	100%	93%
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TBD	70%	100%	100%	100%	100%	70%
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Provincial Total (# Units)	LDC Total (# Units)
1,338,276	35,735
37,518	1,002
16,320	436
12,415	332
14,393	384
10,965	293
9,816	262
5,018	134
217	6
1,984,267	52,985
477,612	12,753
31,484	841
0	665
0	239
1,875	50
n/a	n/a

37,123	632
10,652	214
581	10
325	7
758	11
33,178	922
46,989	1,305
51,990	1,444
28,048	779
21,997	0
2,376,053	65,999
386,799	10,744
500,000	13,888
19,166	532
77,226	2,145
305,048	8,473
30,516	848
19,390	539
9,229	256
629,498	17,486
18,088	502

18,633	518
8,442	234
97,742	2,715
12,360	0
3,733	0
10,364	0
167	0
221	0
9	0
858,039	47,729
174	0
328	0
4	0
154	0
78	0
11	0
12	0
75	0
15	0
920	0
143	0
68	0
23	0
2	0
448	0
30	0
43	0
36	0
5	0
26	0
10	0
35	0
163	0
1,902	0
34	0
104	0
6	0
57	0
19	0
48	0
9,680	269
544	0
0	0
24	0
12	0
n/a	n/a
n/a	n/a
n/a	n/a
n/a	n/a
4	0
3	0
72	0

2	0

62,968	997
18,376	275
1,587	4
9,366	259
4,499	124
7,291	202
0	0
33,546	928
22,241	615
28,505	788
0	0
62,670	215
39,053	1,093
423,741	11,858
657,609	18,402
14,885	417
119,646	3,348
1,526,248	42,709
98,397	2,753
7,055	197
41,495	1,161
n/a	n/a
903,439	25,281
128,609	3,599
28,376	794
457,649	12,806
14,029	393
842,772	23,583
110,248	3,085
263	7
295	8
7,897	221
8,535	239
6,808	191
28,831	97
14,152	1,089
318	2
104	0
47	0
1	0
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18,026	0
287	0
3,256	0
53	0
35	0
1	0
0	0
1,775	0
1	0
3	0
1	0
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1	0

n/a	n/a
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n/a	n/a
n/a	n/a
0	0
7	0
116	2
2	0
2	0

#	Local Distribution Company	2006 Residential Peak Load (kW)	2006 Residential Peak Load (%)
1	Atikokan Hydro Inc.	n/a	n/a
2	Attawapiskat First Nation	n/a	n/a
3	Attawapiskat Power Corporation	n/a	n/a
4	Barrie Hydro Distribution Inc.	n/a	n/a
5	Bluewater Power Distribution Corporation	n/a	n/a
6	Brant County Power Inc.	n/a	n/a
7	Brantford Power Inc.	n/a	n/a
8	Burlington Hydro Inc.	n/a	n/a
9	COLLUS Power Corp.	n/a	n/a
10	Cambridge and North Dumfries Hydro Inc.	n/a	n/a
11	Canadian Niagara Power Inc.	n/a	n/a
12	Centre Wellington Hydro Ltd.	n/a	n/a
13	Chapleau Public Utilities Corporation	n/a	n/a
14	Chatham-Kent Hydro Inc.	n/a	n/a
15	Clinton Power Corporation	n/a	n/a
16	Cooperative Hydro Embrun Inc.	n/a	n/a
17	Cornwall Street Railway Light and Power Company Limited	n/a	n/a
18	Dubreuil Forest Products Ltd.	n/a	n/a
19	Dutton Hydro Limited	n/a	n/a
20	E.L.K. Energy Inc.	n/a	n/a
21	ENWIN Utilities Ltd.	n/a	n/a
22	Enersource Hydro Mississauga Inc.	n/a	n/a
23	Erie Thames Powerlines Corporation	n/a	n/a
24	Espanola Regional Hydro Distribution Corporation	n/a	n/a
25	Essex Powerlines Corporation	n/a	n/a
26	Festival Hydro Inc.	n/a	n/a
27	Fort Albany First Nation	n/a	n/a
28	Fort Albany Power Corporation	n/a	n/a
29	Fort Frances Power Corporation	n/a	n/a
30	Grand Valley Energy Inc	n/a	n/a
31	Great Lakes Power Limited	n/a	n/a
32	Greater Sudbury Hydro Inc.	n/a	n/a
33	Grimsby Power Incorporated	n/a	n/a
34	Guelph Hydro Electric Systems Inc.	n/a	n/a
35	Haldimand County Hydro Inc.	n/a	n/a
36	Halton Hills Hydro Inc.	n/a	n/a
37	Hearst Power Distribution Company Limited	n/a	n/a
38	Horizon Utilities Corporation	n/a	n/a
39	Hydro 2000 Inc.	n/a	n/a
40	Hydro Hawkesbury Inc.	n/a	n/a
41	Hydro One Brampton Networks Inc.	n/a	n/a
42	Hydro One Networks Inc.	n/a	n/a
43	Hydro One Networks Inc./Cat Lake Power Community	n/a	n/a
44	Hydro One Remote Communities Inc.	n/a	n/a
45	Hydro Ottawa Limited	n/a	n/a
46	Innisfil Hydro Distribution Systems Limited	n/a	n/a

47	Kashechewan First Nation	n/a	n/a
48	Kashechewan Power Corporation	n/a	n/a
49	Kenora Hydro Electric Corporation Ltd.	n/a	n/a
50	Kingston Hydro Corporation	n/a	n/a
51	Kitchener-Wilmot Hydro Inc.	n/a	n/a
52	Lakefront Utilities Inc.	n/a	n/a
53	Lakeland Power Distribution Ltd.	n/a	n/a
54	London Hydro Inc.	n/a	n/a
55	Middlesex Power Distribution Corporation	n/a	n/a
56	Midland Power Utility Corporation	n/a	n/a
57	Milton Hydro Distribution Inc.	n/a	n/a
58	Newbury Power Inc.	n/a	n/a
59	Newmarket - Tay Power Distribution Ltd.	n/a	n/a
60	Niagara Peninsula Energy Inc.	n/a	n/a
61	Niagara-on-the-Lake Hydro Inc.	n/a	n/a
62	Norfolk Power Distribution Inc.	n/a	n/a
63	North Bay Hydro Distribution Limited	n/a	n/a
64	Northern Ontario Wires Inc.	n/a	n/a
65	Oakville Hydro Electricity Distribution Inc.	n/a	n/a
66	Orangeville Hydro Limited	n/a	n/a
67	Orillia Power Distribution Corporation	n/a	n/a
68	Oshawa PUC Networks Inc.	n/a	n/a
69	Ottawa River Power Corporation	n/a	n/a
70	PUC Distribution Inc.	n/a	n/a
71	Parry Sound Power Corporation	n/a	n/a
72	Peterborough Distribution Incorporated	n/a	n/a
73	Port Colborne Hydro Inc.	n/a	n/a
74	PowerStream Inc.	n/a	n/a
75	Renfrew Hydro Inc.	n/a	n/a
76	Rideau St. Lawrence Distribution Inc.	n/a	n/a
77	Sioux Lookout Hydro Inc.	n/a	n/a
78	St. Thomas Energy Inc.	n/a	n/a
79	Thunder Bay Hydro Electricity Distribution Inc.	n/a	n/a
80	Tillsonburg Hydro Inc.	n/a	n/a
81	Toronto Hydro-Electric System Limited	n/a	n/a
82	Veridian Connections Inc.	n/a	n/a
83	Wasaga Distribution Inc.	n/a	n/a
84	Waterloo North Hydro Inc.	n/a	n/a
85	Welland Hydro-Electric System Corp.	n/a	n/a
86	Wellington North Power Inc.	n/a	n/a
87	West Coast Huron Energy Inc.	n/a	n/a
88	West Perth Power Inc.	n/a	n/a
89	Westario Power Inc.	n/a	n/a
90	Whitby Hydro Electric Corporation	n/a	n/a
91	Woodstock Hydro Services Inc.	n/a	n/a
Total		**n/a**	**n/a**

2006 Residential Energy Throughput (kWh)	2006 Residential Energy Throughput (%)	2006 Non-Residential Peak Load (kW)	2006 Non-Residential Peak Load (%)	2006 Non-Residential Energy Throughput (kWh)	2006 Non-Residential Energy Throughput (%)
11,400,673	0.03%	n/a	n/a	34,099,588	0.04%
	0.00%	n/a	n/a		0.00%
	0.00%	n/a	n/a		0.00%
530,557,254	1.32%	n/a	n/a	937,360,428	1.20%
261,470,152	0.65%	n/a	n/a	842,737,021	1.08%
79,563,205	0.20%	n/a	n/a	145,133,733	0.19%
284,501,278	0.71%	n/a	n/a	680,671,928	0.87%
551,419,663	1.37%	n/a	n/a	1,182,280,000	1.51%
110,110,859	0.27%	n/a	n/a	225,767,061	0.29%
389,897,758	0.97%	n/a	n/a	1,175,499,726	1.50%
143,693,705	0.36%	n/a	n/a	215,257,881	0.27%
44,421,203	0.11%	n/a	n/a	104,851,041	0.13%
14,654,854	0.04%	n/a	n/a	13,456,323	0.02%
239,607,514	0.60%	n/a	n/a	615,842,408	0.79%
12,656,005	0.03%	n/a	n/a	5,883,572	0.01%
19,799,972	0.05%	n/a	n/a	9,670,245	0.01%
	0.00%	n/a	n/a	3,316,831	0.00%
	0.00%	n/a	n/a	104,680,214	0.13%
409,958	0.00%	n/a	n/a	244,729,136	0.31%
91,182,112	0.23%	n/a	n/a	45,502,520	0.06%
655,143,475	1.63%	n/a	n/a	244,729,136	0.31%
1,603,332,097	3.98%	n/a	n/a	6,490,116,773	8.28%
116,103,693	0.29%	n/a	n/a	36,572,686	0.05%
32,486,898	0.08%	n/a	n/a	30,450,548	0.04%
284,492,550	0.71%	n/a	n/a	148,696,240	0.19%
142,060,467	0.35%	n/a	n/a	471,908,335	0.60%
	0.00%	n/a	n/a		0.00%
	0.00%	n/a	n/a		0.00%
38,401,315	0.10%	n/a	n/a	42,879,081	0.05%
5,683,369	0.01%	n/a	n/a	2,812,411	0.00%
91,383,636	0.23%	n/a	n/a	102,068,591	0.13%
397,678,409	0.99%	n/a	n/a	535,059,474	0.68%
85,590,583	0.21%	n/a	n/a	18,314,103	0.02%
357,495,622	0.89%	n/a	n/a	1,264,636,266	1.61%
172,359,424	0.43%	n/a	n/a	185,282,283	0.24%
200,925,506	0.50%	n/a	n/a	271,457,391	0.35%
26,681,677	0.07%	n/a	n/a	87,318,533	0.11%
1,654,664,050	4.11%	n/a	n/a	3,638,046,674	4.64%
15,223,723	0.04%	n/a	n/a	10,268,966	0.01%
54,802,923	0.14%	n/a	n/a	143,819,890	0.18%
1,075,118,931	2.67%	n/a	n/a	2,744,176,570	3.50%
12,237,925,130	30.40%	n/a	n/a	9,935,112,037	12.68%
	0.00%	n/a	n/a		0.00%
	0.00%	n/a	n/a		0.00%
2,226,415,669	5.53%	n/a	n/a	5,188,092,986	6.62%
157,140,654	0.39%	n/a	n/a	28,964,493	0.04%

	0.00%	n/a	n/a		0.00%
	0.00%	n/a	n/a		0.00%
39,159,513	0.10%	n/a	n/a	68,402,801	0.09%
200,214,258	0.50%	n/a	n/a	531,028,042	0.68%
644,108,007	1.60%	n/a	n/a	1,309,299,590	1.67%
67,942,208	0.17%	n/a	n/a	213,381,240	0.27%
78,930,880	0.20%	n/a	n/a	45,933,794	0.06%
1,088,755,114	2.70%	n/a	n/a	2,244,907,930	2.87%
57,128,547	0.14%	n/a	n/a	145,163,360	0.19%
43,734,088	0.11%	n/a	n/a	177,618,443	0.23%
197,466,598	0.49%	n/a	n/a	439,013,389	0.56%
	0.00%	n/a	n/a		0.00%
262,995,579	0.65%	n/a	n/a	93,266,581	0.12%
449,386,643	1.12%	n/a	n/a	809,188,538	1.03%
63,805,148	0.16%	n/a	n/a	111,101,732	0.14%
139,960,236	0.35%	n/a	n/a	237,962,119	0.30%
207,199,584	0.51%	n/a	n/a	349,174,613	0.45%
43,040,214	0.11%	n/a	n/a	91,314,990	0.12%
569,566,301	1.41%	n/a	n/a	994,238,859	1.27%
79,376,454	0.20%	n/a	n/a	160,927,606	0.21%
108,206,276	0.27%	n/a	n/a	209,218,547	0.27%
465,431,095	1.16%	n/a	n/a	632,361,055	0.81%
75,536,829	0.19%	n/a	n/a	116,088,912	0.15%
335,395,539	0.83%	n/a	n/a	353,865,433	0.45%
33,103,725	0.08%	n/a	n/a	51,649,272	0.07%
290,645,501	0.72%	n/a	n/a	512,167,589	0.65%
63,748,755	0.16%	n/a	n/a	131,007,820	0.17%
2,003,371,840	4.98%	n/a	n/a	4,700,083,921	6.00%
30,640,237	0.08%	n/a	n/a	65,574,034	0.08%
44,343,815	0.11%	n/a	n/a	22,573,648	0.03%
31,452,628	0.08%	n/a	n/a	60,136,389	0.08%
113,523,979	0.28%	n/a	n/a	250,600,744	0.32%
346,415,246	0.86%	n/a	n/a	681,186,819	0.87%
52,306,081	0.13%	n/a	n/a	175,367,100	0.22%
5,351,746,739	13.29%	n/a	n/a	20,069,911,519	25.61%
929,432,918	2.31%	n/a	n/a	1,583,103,519	2.02%
73,495,682	0.18%	n/a	n/a	31,661,531	0.04%
391,947,018	0.97%	n/a	n/a	922,560,313	1.18%
169,952,289	0.42%	n/a	n/a	314,737,340	0.40%
25,536,958	0.06%	n/a	n/a	68,059,736	0.09%
27,222,139	0.07%	n/a	n/a	119,067,345	0.15%
	0.00%	n/a	n/a		0.00%
207,243,931	0.51%	n/a	n/a	243,567,288	0.31%
337,897,948	0.84%	n/a	n/a	511,216,232	0.65%
104,833,112	0.26%	n/a	n/a	300,154,329	0.38%
40,262,655,618	**100.00%**	**n/a**	**n/a**	**78,355,367,185**	**100.00%**

2007 Residential Peak Load (kW)	2007 Residential Peak Load (%)	2007 Residential Energy Throughput (kWh)	2007 Residential Energy Throughput (%)	2007 Non-Residential Peak Load (kW)	2007 Non-Residential Peak Load (%)
n/a	n/a	11,858,778	0.03%	n/a	n/a
n/a	n/a		0.00%	n/a	n/a
n/a	n/a		0.00%	n/a	n/a
n/a	n/a	548,016,272	1.33%	n/a	n/a
n/a	n/a	264,836,003	0.64%	n/a	n/a
n/a	n/a	81,004,255	0.20%	n/a	n/a
n/a	n/a	298,531,289	0.73%	n/a	n/a
n/a	n/a	567,063,035	1.38%	n/a	n/a
n/a	n/a	113,589,579	0.28%	n/a	n/a
n/a	n/a	395,062,443	0.96%	n/a	n/a
n/a	n/a	143,862,348	0.35%	n/a	n/a
n/a	n/a	46,699,194	0.11%	n/a	n/a
n/a	n/a	15,018,918	0.04%	n/a	n/a
n/a	n/a	236,072,777	0.57%	n/a	n/a
n/a	n/a	12,522,951	0.03%	n/a	n/a
n/a	n/a	19,386,628	0.05%	n/a	n/a
n/a	n/a		0.00%	n/a	n/a
n/a	n/a		0.00%	n/a	n/a
n/a	n/a		0.00%	n/a	n/a
n/a	n/a	94,171,770	0.23%	n/a	n/a
n/a	n/a	664,998,752	1.62%	n/a	n/a
n/a	n/a	1,632,816,129	3.97%	n/a	n/a
n/a	n/a	116,256,740	0.28%	n/a	n/a
n/a	n/a	32,040,530	0.08%	n/a	n/a
n/a	n/a	280,966,066	0.68%	n/a	n/a
n/a	n/a	143,658,315	0.35%	n/a	n/a
n/a	n/a		0.00%	n/a	n/a
n/a	n/a		0.00%	n/a	n/a
n/a	n/a	39,011,690	0.09%	n/a	n/a
n/a	n/a	5,786,652	0.01%	n/a	n/a
n/a	n/a	92,360,867	0.22%	n/a	n/a
n/a	n/a	405,736,204	0.99%	n/a	n/a
n/a	n/a	86,770,666	0.21%	n/a	n/a
n/a	n/a	358,331,164	0.87%	n/a	n/a
n/a	n/a	173,795,327	0.42%	n/a	n/a
n/a	n/a	208,287,499	0.51%	n/a	n/a
n/a	n/a	28,317,089	0.07%	n/a	n/a
n/a	n/a	1,666,789,557	4.06%	n/a	n/a
n/a	n/a	15,036,848	0.04%	n/a	n/a
n/a	n/a	56,403,314	0.14%	n/a	n/a
n/a	n/a	1,141,600,000	2.78%	n/a	n/a
n/a	n/a	12,620,681,000	30.71%	n/a	n/a
n/a	n/a		0.00%	n/a	n/a
n/a	n/a		0.00%	n/a	n/a
n/a	n/a	2,234,039,085	5.44%	n/a	n/a
n/a	n/a	156,705,342	0.38%	n/a	n/a

n/a	n/a		0.00%	n/a	n/a
n/a	n/a		0.00%	n/a	n/a
n/a	n/a	39,142,088	0.10%	n/a	n/a
n/a	n/a	221,960,966	0.54%	n/a	n/a
n/a	n/a	660,550,766	1.61%	n/a	n/a
n/a	n/a	74,685,958	0.18%	n/a	n/a
n/a	n/a	78,209,625	0.19%	n/a	n/a
n/a	n/a	1,117,283,048	2.72%	n/a	n/a
n/a	n/a	57,541,659	0.14%	n/a	n/a
n/a	n/a	47,886,438	0.12%	n/a	n/a
n/a	n/a	218,633,202	0.53%	n/a	n/a
n/a	n/a	463,355	0.00%	n/a	n/a
n/a	n/a	270,904,453	0.66%	n/a	n/a
n/a	n/a	423,910,347	1.03%	n/a	n/a
n/a	n/a	65,561,722	0.16%	n/a	n/a
n/a	n/a	142,543,771	0.35%	n/a	n/a
n/a	n/a	213,131,701	0.52%	n/a	n/a
n/a	n/a	43,226,412	0.11%	n/a	n/a
n/a	n/a	592,214,968	1.44%	n/a	n/a
n/a	n/a	80,135,717	0.19%	n/a	n/a
n/a	n/a	109,590,116	0.27%	n/a	n/a
n/a	n/a	495,109,283	1.20%	n/a	n/a
n/a	n/a	75,938,194	0.18%	n/a	n/a
n/a	n/a	338,874,337	0.82%	n/a	n/a
n/a	n/a	34,279,947	0.08%	n/a	n/a
n/a	n/a	286,683,602	0.70%	n/a	n/a
n/a	n/a	65,276,304	0.16%	n/a	n/a
n/a	n/a	2,039,498,572	4.96%	n/a	n/a
n/a	n/a	31,007,901	0.08%	n/a	n/a
n/a	n/a	45,086,486	0.11%	n/a	n/a
n/a	n/a	32,814,076	0.08%	n/a	n/a
n/a	n/a	119,400,889	0.29%	n/a	n/a
n/a	n/a	344,508,404	0.84%	n/a	n/a
n/a	n/a	52,893,412	0.13%	n/a	n/a
n/a	n/a	5,332,356,184	12.97%	n/a	n/a
n/a	n/a	960,984,164	2.34%	n/a	n/a
n/a	n/a	78,007,343	0.19%	n/a	n/a
n/a	n/a	405,071,611	0.99%	n/a	n/a
n/a	n/a	162,857,785	0.40%	n/a	n/a
n/a	n/a	25,027,983	0.06%	n/a	n/a
n/a	n/a	26,672,783	0.06%	n/a	n/a
n/a	n/a	15,466,784	0.04%	n/a	n/a
n/a	n/a	213,039,032	0.52%	n/a	n/a
n/a	n/a	347,926,496	0.85%	n/a	n/a
n/a	n/a	104,412,330	0.25%	n/a	n/a
n/a	**n/a**	**41,098,855,290**	**100.00%**	**n/a**	**n/a**

2007 Non-Residential Energy Throughput (kWh)	2007 Non-Residential Energy Throughput (%)	2008 Residential Peak Load (kW)	2008 Residential Peak Load (%)	2008 Residential Energy Throughput (kWh)	2008 Residential Energy Throughput (%)
31,082,191	0.04%	n/a	n/a	11,183,350	0.03%
	0.00%	n/a	n/a	0	0.00%
	0.00%	n/a	n/a	0	0.00%
940,740,837	1.14%	n/a	n/a	547,117,234	1.35%
855,922,144	1.04%	n/a	n/a	261,354,534	0.64%
207,717,221	0.25%	n/a	n/a	79,817,804	0.20%
741,598,484	0.90%	n/a	n/a	291,972,257	0.72%
1,199,736,238	1.45%	n/a	n/a	557,752,794	1.37%
215,072,148	0.26%	n/a	n/a	114,695,863	0.28%
1,165,105,313	1.41%	n/a	n/a	384,779,246	0.95%
215,810,521	0.26%	n/a	n/a	141,136,541	0.35%
111,831,932	0.14%	n/a	n/a	44,627,090	0.11%
13,186,691	0.02%	n/a	n/a	15,056,281	0.04%
601,416,856	0.73%	n/a	n/a	232,973,162	0.57%
18,085,796	0.02%	n/a	n/a	0	0.00%
9,298,043	0.01%	n/a	n/a	19,644,024	0.05%
	0.00%	n/a	n/a	0	0.00%
	0.00%	n/a	n/a	0	0.00%
	0.00%	n/a	n/a	0	0.00%
160,761,797	0.19%	n/a	n/a	93,091,229	0.23%
1,903,884,798	2.31%	n/a	n/a	637,053,725	1.57%
6,605,288,225	8.00%	n/a	n/a	1,590,715,870	3.92%
291,852,488	0.35%	n/a	n/a	115,637,295	0.28%
31,021,479	0.04%	n/a	n/a	32,354,293	0.08%
279,180,331	0.34%	n/a	n/a	261,929,749	0.65%
468,128,577	0.57%	n/a	n/a	140,987,205	0.35%
	0.00%	n/a	n/a	0	0.00%
	0.00%	n/a	n/a	0	0.00%
43,615,480	0.05%	n/a	n/a	39,844,007	0.10%
3,568,735	0.00%	n/a	n/a	5,882,230	0.01%
109,854,997	0.13%	n/a	n/a	87,951,272	0.22%
543,747,565	0.66%	n/a	n/a	411,072,289	1.01%
88,449,813	0.11%	n/a	n/a	91,344,616	0.23%
1,269,317,570	1.54%	n/a	n/a	366,970,148	0.90%
183,754,191	0.22%	n/a	n/a	171,781,095	0.42%
311,739,725	0.38%	n/a	n/a	220,683,563	0.54%
82,118,980	0.10%	n/a	n/a	26,743,823	0.07%
4,575,455,672	5.54%	n/a	n/a	1,641,702,487	4.04%
9,877,930	0.01%	n/a	n/a	15,306,507	0.04%
145,226,883	0.18%	n/a	n/a	55,769,040	0.14%
2,798,700,000	3.39%	n/a	n/a	1,136,600,000	2.80%
10,298,799,000	12.47%	n/a	n/a	12,410,000,000	30.57%
	0.00%	n/a	n/a	0	0.00%
	0.00%	n/a	n/a	0	0.00%
5,255,181,082	6.36%	n/a	n/a	2,226,078,653	5.48%
71,986,330	0.09%	n/a	n/a	158,043,498	0.39%

	0.00%	n/a	n/a	0	0.00%
	0.00%	n/a	n/a	0	0.00%
70,186,402	0.08%	n/a	n/a	39,338,336	0.10%
497,012,043	0.60%	n/a	n/a	200,853,045	0.49%
1,312,172,498	1.59%	n/a	n/a	659,163,062	1.62%
215,906,659	0.26%	n/a	n/a	75,604,253	0.19%
135,514,735	0.16%	n/a	n/a	81,234,268	0.20%
2,246,550,773	2.72%	n/a	n/a	1,119,770,671	2.76%
139,592,176	0.17%	n/a	n/a	57,013,718	0.14%
175,517,601	0.21%	n/a	n/a	48,136,133	0.12%
470,712,726	0.57%	n/a	n/a	225,897,498	0.56%
606,285	0.00%	n/a	n/a	0	0.00%
96,866,788	0.12%	n/a	n/a	268,062,456	0.66%
853,493,894	1.03%	n/a	n/a	400,445,564	0.99%
112,958,244	0.14%	n/a	n/a	63,512,671	0.16%
236,960,151	0.29%	n/a	n/a	140,646,761	0.35%
353,433,822	0.43%	n/a	n/a	213,813,392	0.53%
87,800,701	0.11%	n/a	n/a	41,990,761	0.10%
1,015,760,199	1.23%	n/a	n/a	588,349,444	1.45%
165,400,748	0.20%	n/a	n/a	79,576,857	0.20%
208,616,563	0.25%	n/a	n/a	109,814,584	0.27%
685,818,845	0.83%	n/a	n/a	493,225,543	1.22%
84,784,890	0.10%	n/a	n/a	78,434,655	0.19%
355,019,853	0.43%	n/a	n/a	347,363,230	0.86%
54,561,642	0.07%	n/a	n/a	34,188,975	0.08%
525,620,624	0.64%	n/a	n/a	288,028,301	0.71%
125,625,452	0.15%	n/a	n/a	64,024,829	0.16%
4,749,900,082	5.75%	n/a	n/a	2,077,903,209	5.12%
67,121,871	0.08%	n/a	n/a	31,465,398	0.08%
67,416,920	0.08%	n/a	n/a	44,465,236	0.11%
57,375,461	0.07%	n/a	n/a	33,587,664	0.08%
244,392,868	0.30%	n/a	n/a	120,297,987	0.30%
669,420,045	0.81%	n/a	n/a	351,645,318	0.87%
183,570,981	0.22%	n/a	n/a	51,050,818	0.13%
20,316,766,672	24.60%	n/a	n/a	5,215,687,193	12.85%
1,566,734,483	1.90%	n/a	n/a	942,451,035	2.32%
35,464,935	0.04%	n/a	n/a	76,997,980	0.19%
954,721,743	1.16%	n/a	n/a	405,533,476	1.00%
300,569,977	0.36%	n/a	n/a	157,955,849	0.39%
69,405,347	0.08%	n/a	n/a	25,485,646	0.06%
117,989,487	0.14%	n/a	n/a	26,528,425	0.07%
46,047,710	0.06%	n/a	n/a	0	0.00%
246,987,034	0.30%	n/a	n/a	213,227,356	0.53%
511,966,838	0.62%	n/a	n/a	346,038,642	0.85%
287,974,277	0.35%	n/a	n/a	110,536,185	0.27%
82,578,437,108	**100.00%**	**n/a**	**n/a**	**40,588,999,198**	**100.00%**

2008 Non-Residential Peak Load (kW)	2008 Non-Residential Peak Load (%)	2008 Non-Residential Energy Throughput (kWh)	2008 Non-Residential Energy Throughput (%)
n/a	n/a	14,843,605	0.02%
n/a	n/a	0	0.00%
n/a	n/a	0	0.00%
n/a	n/a	980,805,847	1.21%
n/a	n/a	821,568,128	1.02%
n/a	n/a	200,988,235	0.25%
n/a	n/a	719,465,778	0.89%
n/a	n/a	1,158,340,390	1.43%
n/a	n/a	205,759,520	0.25%
n/a	n/a	1,125,532,050	1.39%
n/a	n/a	206,108,617	0.25%
n/a	n/a	113,895,413	0.14%
n/a	n/a	13,204,594	0.02%
n/a	n/a	578,228,629	0.71%
n/a	n/a	0	0.00%
n/a	n/a	9,451,266	0.01%
n/a	n/a	0	0.00%
n/a	n/a	0	0.00%
n/a	n/a	0	0.00%
n/a	n/a	157,019,403	0.19%
n/a	n/a	1,801,822,532	2.23%
n/a	n/a	6,464,408,854	7.99%
n/a	n/a	278,295,099	0.34%
n/a	n/a	30,605,267	0.04%
n/a	n/a	278,831,202	0.34%
n/a	n/a	448,339,012	0.55%
n/a	n/a	0	0.00%
n/a	n/a	0	0.00%
n/a	n/a	42,938,079	0.05%
n/a	n/a	3,097,510	0.00%
n/a	n/a	89,322,297	0.11%
n/a	n/a	546,788,157	0.68%
n/a	n/a	87,677,058	0.11%
n/a	n/a	1,223,442,614	1.51%
n/a	n/a	177,498,802	0.22%
n/a	n/a	276,894,738	0.34%
n/a	n/a	56,718,432	0.07%
n/a	n/a	4,317,582,512	5.34%
n/a	n/a	10,138,585	0.01%
n/a	n/a	138,066,467	0.17%
n/a	n/a	2,748,900,000	3.40%
n/a	n/a	9,990,000,000	12.35%
n/a	n/a	0	0.00%
n/a	n/a	0	0.00%
n/a	n/a	5,274,086,924	6.52%
n/a	n/a	78,175,459	0.10%

n/a	n/a	0	0.00%
n/a	n/a	0	0.00%
n/a	n/a	69,225,456	0.09%
n/a	n/a	535,320,723	0.66%
n/a	n/a	1,257,832,920	1.56%
n/a	n/a	205,196,563	0.25%
n/a	n/a	136,289,494	0.17%
n/a	n/a	2,189,969,229	2.71%
n/a	n/a	132,646,565	0.16%
n/a	n/a	166,162,739	0.21%
n/a	n/a	476,230,193	0.59%
n/a	n/a	0	0.00%
n/a	n/a	452,921,581	0.56%
n/a	n/a	813,890,886	1.01%
n/a	n/a	109,639,488	0.14%
n/a	n/a	230,446,897	0.28%
n/a	n/a	349,313,014	0.43%
n/a	n/a	78,987,933	0.10%
n/a	n/a	991,360,456	1.23%
n/a	n/a	159,288,984	0.20%
n/a	n/a	206,291,735	0.26%
n/a	n/a	661,990,009	0.82%
n/a	n/a	114,881,644	0.14%
n/a	n/a	355,446,428	0.44%
n/a	n/a	53,124,268	0.07%
n/a	n/a	525,236,456	0.65%
n/a	n/a	127,071,772	0.16%
n/a	n/a	4,705,762,883	5.82%
n/a	n/a	69,352,093	0.09%
n/a	n/a	65,825,492	0.08%
n/a	n/a	42,670,262	0.05%
n/a	n/a	220,058,899	0.27%
n/a	n/a	644,339,043	0.80%
n/a	n/a	165,205,863	0.20%
n/a	n/a	19,811,187,290	24.50%
n/a	n/a	1,538,562,235	1.90%
n/a	n/a	37,455,844	0.05%
n/a	n/a	956,629,104	1.18%
n/a	n/a	304,094,821	0.38%
n/a	n/a	67,434,118	0.08%
n/a	n/a	126,738,954	0.16%
n/a	n/a	0	0.00%
n/a	n/a	254,222,507	0.31%
n/a	n/a	500,707,723	0.62%
n/a	n/a	295,103,216	0.36%
n/a	**n/a**	**80,872,956,854**	**100.00%**

APPENDIX AE

IndEco

Strategic Solutions for a Changing World™

Hydro One Brampton Networks Inc. LRAM/SSM

Third party review:

Hydro One Brampton Networks Inc.
LRAM and SSM claims

IndEco

This document was prepared for Hydro One Brampton Networks Inc. by IndEco Strategic Consulting Inc.

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IndEco report B0566

9 June 2010

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Executive summary

A third party review of the Conservation and Demand Management (CDM) programs run by Hydro One Brampton Networks Inc. (HOB) was required as part of its application to the Ontario Energy Board (OEB) for collection of Lost Revenue Adjustment Mechanism (LRAM) and Shared Savings Mechanism (SSM) claims.

IndEco Strategic Consulting Inc. (IndEco) acted as third party reviewer by examining the participant rates, program costs, equipment specifications, and calculations that enter into the energy savings and Total Resource Costs (TRC) submitted by HOB to the OEB. The review was completed as detailed in the OEB *Guidelines for Electricity Distributor Conservation and Demand Management*.

The third party review included HOB's CDM activities in 2005, 2006, 2007 and 2008 supported through Third Tranche of Market Adjustment Revenue Requirement (MARR) funding, and Ontario Power Authority (OPA) funding.

Net benefits, calculated using the TRC test, used OEB recommended inputs. For prescriptive programs, inputs were taken primarily from the OEB *Total Resource Cost Guide*, or program evaluations provided by the OPA. Where these were incomplete, values were taken from the OPA's *2010 Prescriptive Measures and Assumptions*, and *2010 Quasi-prescriptive Measure and Assumptions*. TRC inputs for custom programs also relied upon manufacturer specifications and HOB's evaluations. Net TRC benefits totalled over $9.1 million dollars.

Lost revenues are calculated using estimated energy savings or monthly peak demand savings using the best available and most current input assumptions. Energy savings originally reported in Hydro One Brampton Networks's annual filings have been updated to reflect new assumptions available since then, including more recent input assumptions from the OPA, and the results of OPA's program evaluations. In the span of six years, these savings totalled over 108 GWh in the residential rate class and 0.106 GWh in the GS < 50 kW rate class. Savings in the GS 50 to 699 kW and the GS 700 to 4,999 kW totalled approximately 18,000 and 28,000 kW-months, respectively.

IndEco concludes that HOB's electricity rates should be adjusted to reflect LRAM and SSM claims of $1,937,159 and $458,438 respectively.

Introduction

Lost Revenue Adjustment Mechanism and Shared Savings Mechanism claims can benefit a local distribution company (LDC) by removing the disincentive for energy conservation, and by providing it with a portion of net economic benefits from conservation and demand management activities, respectively.

LRAM is designed to ensure that the LDC does not have a disincentive to promote energy efficiency and energy conservation by compensating the LDC for revenues lost as a result of its conservation initiatives. It requires the calculation of electricity savings over the period between the last rate application, and the time of the application. In turn, this calculation requires information on what the electricity use would have been in the absence of the LDC initiatives, and what it was with the LDC initiative. Some of the inputs to the calculation include: hours the equipment is used, wattage rating of the old and new equipment, and lifetime of the equipment if it is less than the period over which the LRAM is being claimed. Also required are the number of participants, or pieces of equipment installed, and an estimate of the free-rider rate, which is the fraction of the savings that would have occurred anyway, in the absence of the program. These savings are estimated by rate class, and revenue losses are determined by multiplying those losses by the cost of distribution per unit for each rate class. Carrying charges are calculated using deferral and variance account interest rates prescribed by the OEB.[1]

The SSM rewards the LDC for its CDM initiatives by sharing a percentage of the net economic benefits that result from the initiatives over their lifetime. For CDM activities by Ontario electricity distributors, that percentage has been set at five percent by the Ontario Energy Board (OEB). Key inputs to the calculation of SSM include all of the LRAM inputs, and in addition, the total lifetime of each technology installed, equipment costs, program costs, projected electricity costs (and water and natural gas if relevant) over that lifetime.

Although these input data requirements are sometimes measured, they sometimes use values from published sources, or assumptions provided by the Ontario Energy Board, or other reputable agencies. Collectively all these data are sometimes referred to as “TRC inputs” after the Total Resource Cost test that is used to calculate total economic costs and benefits to society. For some types of programs, such as large scale distribution of compact fluorescent bulbs, it would be impractical to measure the hours each bulb is used, and therefore these published sources provide an average value that is typical for this equipment type.

In some cases, estimated values for a particular component of the calculation are available from multiple sources. In these cases,

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[1] For prescribed interest rates, see http://www.oeb.gov.on.ca/OEB/Industry/Rules+and+Requirements/Rules+Codes+Guidelines+and+Forms/Prescribed+Interest+Rates

information is taken from the sources highest in the information hierarchy. The information hierarchy (from greatest to least confidence) for LRAM calculations is:

1. Information or results from an OPA conducted or sponsored evaluation of the specific program (e.g. OPA 2009)
2. Information or results from a third-party evaluation of the specific program
3. Information or results from a site-specific assessment of the application of the technology, including on-site measurement or survey of the specific customer
4. Manufacturer specifications for energy use/demand of a technology
5. Information from the OPA's most current measures and assumptions lists (OPA 2010a, OPA 2010b)
6. Information from earlier OPA measures and assumptions lists
7. Information from the OEB's TRC guide list of measures and assumptions.

In principal, we might have consulted values from the literature and adopted these if they could be shown to be more current, specific or otherwise suitable than the values from sources 4 through 7. However, this was not necessary in this case.

The CDM programs undertaken by Hydro One Brampton Networks Inc. between 2005 and 2008 included:

- Installing real-time electricity consumption monitors in residential homes;
- Distributing energy efficient seasonal LED lights;
- Providing incentives to commercial and industrial customers for the installation of energy efficient lighting;
- Upgrading of lighting at HOB's offices, and installation of a photo voltaic system;
- Distribution of CFLs to each residence in Brampton;
- Public and general services education and outreach programs;
- Introducing an on-line energy audit for residential and commercial customers;
- Retrofitting a residential high-rise building with energy efficient appliances. This was done in partnership with Hydro One Brampton Networks as part of an initiative undertaken with the Social Housing Services Corporation and social housing providers.
- Partnership with or delivery of OPA-funded programs, including Every Kilowatt Counts (EKC), ***peaksaver***®, the Great Refrigerator Roundup, Demand Response, the Renewable Energy Standard Offer Program, the Summer Savings Program, Power Savings Blitz and the Electricity Retrofit Incentive Program (ERIP).

Between 2005 and 2010 (inclusive), these programs led to savings of over 108 GWh in the residential rate class and 0.106 GWh in the GS < 50 kW rate class. In the larger general service rate classes, where distribution charges are based on monthly peak kilowatt use, the savings over the six years are approximately 18,000 and 28,000 kW-months in the GS 50-699 kW and the GS 700-4,999 kW rate classes, respectively.

Net TRC benefits totalled over $9.1 million dollars.

Scope

This review examines the measures, energy savings, program costs and net TRC benefits for the fifteen programs in HOB's third tranche CDM portfolio. These programs ran from 2005 until completion as of December 31, 2007. It also includes programs run under contract to the Ontario Power Authority (OPA) in 2006, 2007 and 2008.

Four programs omitted from this review are:

- Two smart meter programs (the Conservation Assets program and the Smart Metering program)
- The Hydro One Brampton Networks Distribution Efficiency program.
- The Commercial and Industrial Power Correction Factor program.

The two smart meter programs were omitted from CDM cost recovery assessment since cost recovery of smart meter programs is done under a separate OEB variance account.[2]

The Hydro One Brampton Networks Distribution Efficiency program was excluded in accordance with the OEB instruction that distribution system improvements are not eligible for the shared savings mechanism.[3]

The Commercial and Industrial Power Correction Factor program was omitted from CDM cost recovery since it too was considered a distribution system improvement. The aim of this program was to reduce the kVA demand on the grid and the benefits of this program are measured by avoided kVA costs. This program primarily benefits HOB and not its customers, directly.

In addition to these four omitted programs, the energy savings (but not the costs) associated with the 2006 Holiday Light Exchange were also not considered for the LRAM claim. The lights given out as part of this program were ultimately recalled and replaced with gift cards that could be redeemed for a number of energy efficient products. However, there is no information available on actual redemption rate, or what products were purchased.

The monthly demand savings of the photovoltaic system installed on-site at the Hydro One Brampton Networks' offices were also not considered for the LRAM claim because they are not deemed material.

In the TRC calculation, benefits and costs are reported in current dollars, which requires a discount rate for future dollars. Even though these activities are at the margin, OEB has dictated that the discount

[2] See OEB Smart Metering Funding and Cost Recovery (File no: G-2008-002).

[3] OEB, 2007. Report of the Board on the Regulatory Framework for Conservation and Demand Management by Ontario Electricity Distributors in 2007 and Beyond. (March 2). p.12

rate to be used is the weighted average cost of capital (WACC). The WACC provided by HOB is as follows:

- 2005-2007: 7.87%

Because the WACC is only used to calculate present values for TRC calculations for the SSM, it is only required for these three years in which distributor-funded programs were offered.

TRC inputs, and requested SSM and LRAM amounts

TRC inputs

Inputs used to calculate energy savings, TRC costs and TRC benefits for each prescriptive and custom measure were reviewed to ensure accuracy and suitability.

IndEco finds that appropriate measure specifications were used to calculate program energy savings and net TRC benefits. For the calculation of LRAM claims, prescriptive measures used values provided by the 2010 OPA Measures and Assumptions list. For the calculation of SSM claims, the best available information at the beginning of the year the program was launched was used, not the 2010 OPA Measures and Assumptions list. This is consistent with the guidance in section 7.3 of the *OEB Guidelines for Electricity CDM*. Custom measures were substantiated through documentation such as invoices of equipment type, wattage, and costs.

Exceptions to the sources of prescriptive measure input assumptions used in the calculation of LRAM claims are as follows:

- The '2006-2008 OPA Conservation Results. Hydro One Brampton Networks Inc.'[4] was used as a source of inputs for OPA funded CDM programs. These evaluated results have been adopted in accordance with Board recommendations that "The Board would consider an evaluation by the OPA or a third party designated by the OPA to be sufficient."[5] OPA advises that these estimates are prepared in a manner consistent with OPA current practice, and are the same values used to report progress against provincial conservation targets.
- One measure from the 2005 Residential Mass Market Coupon Initiative was not found on the 2010 OPA Measures and Assumptions list. The most current assumptions were used.[6]
- The C/I Load Control program used manufacturer specifications provided by HOB's lighting contractor Trico Energy Services (Trico 2007) for energy savings and information provided by the participants for annual operating hours.
- The 2005 Residential Real Time Monitoring pilot consisted of non-prescriptive measures. LRAM and SSM calculations were based on measure information provided by HOB.

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[4] OPA 2009. 2006-8 OPA Conservation Program Results – Hydro One Brampton. E-mail from R. Bunker (OPA) dated 10 November

[5] OEB 2008a. Guidelines for Electricity Distributor Conservation and Demand Management. p.28

[6] These assumptions were provided in a report on program results completed by SeeLine for the 2005 Residential Mass Market Coupon Initiative.

Default free-rider rates of 30% for LRAM calculations and 10% for SSM calculations were used for the majority of programs in HOB's CDM portfolio.

Exceptions to the default values proposed by the OEB and the OPA are as follows:

- All OPA programs used the program-specific free-rider rates provided by the 2006-2008 OPA Conservation Results for Hydro One Brampton Networks Inc.
- The 2005 Residential Real Time Monitoring pilot provided 21 customers with monitors that measured the electrical consumption of their homes in real-time. These monitors would not have been installed in the absence of the CDM program; the program's free-rider rate is thus 0%.
- As part of the 2007 C/I Load Control program, HOB upgraded the lighting in its own facility and installed a photo voltaic system. These were initiatives that were not budgeted for or planned, but were put into place once the third-tranche CDM funding was offered. HOB has advised that because it would not have undertaken these initiatives in the absence of the CDM program, the appropriate free-rider rate for these measures is 0%.

A summary list of the assumption sources used for the calculation of the LRAM claim is provided in Table 1.

Table 1 – Source and values of assumptions used for the calculation of the LRAM claim

Funding source	Rate class	Program	Source of LRAM inputs
Third Tranche	Residential	2005 Residential Holiday LED Lighting	OPA 2010a
	Residential	2005 Residential Mass Market Coupon Initiative	OPA 2010a and SeeLine 2006[1]
	Residential	2005 Residential Real Time Monitoring Pilot	Mountain 2006[2]
	Residential	2006 CFL Distributed by HOB	OPA 2010a
	Residential	2006 Fall EKC Program	OPA 2009
	Residential	2006 Spring EKC Program	OPA 2009
	Residential	2007 CFL Distributed by HOB	OPA 2010a
	Residential	2007 EKC Program	OPA 2009
	GS 50 to 699 and GS 700 to 4999	2007 C/I Load Control Program	OPA 2010b and Trico 2007[3]
OPA	Residential	2006 Cool Savings Rebate	OPA 2009
	Residential	2007 Cool Savings Rebate	OPA 2009
	Residential	2007 Great Refrigerator Roundup	OPA 2009
	Residential	2007 Summer Savings	OPA 2009
	Residential	2008 Cool Savings Rebate	OPA 2009
	Residential	2008 EKC Program	OPA 2009
	Residential	2008 Great Refrigerator Roundup	OPA 2009
	Residential	2008 peaksaver®	OPA 2009
	Residential	2008 Summer Sweepstakes	OPA 2009
	GS 50 to 699 and GS 700 to 4999	2008 Electricity Retrofit Incentive	OPA 2009
	GS < 50	2008 High Performance New Construction	OPA 2009
	GS < 50	2008 Renewable Energy Standard Offer	OPA 2009

1. SeeLine 2006 was used for input assumptions for one measure not found in OPA 2010a: AC indoor timers.

2. The LRAM inputs for the 2005 Residential Real Time Monitoring Pilot are those provided by the real-time monitoring of the 21 program participants.

3. Energy savings were calculated based on the energy efficient and base measure information provided by Trico 2007. The measure life in years for each measure was derived from the annual operating hours of each measure (as provided by Trico 2007 worksheets based on customer surveys) and the ballast lifetime provided in OPA 2010b, Prescriptive measures and assumptions.

A summary list of the information sources used for the calculation of the SSM claim is provided in Table 2.

Table 2 – Source of information used for the calculation of the SSM claim

Funding source	Rate class	Program	Source of SSM inputs
Third Tranche	Residential	2005 Residential Holiday LED Lighting	OEB 2008b and SeeLine 2006
Third Tranche	Residential	2005 Residential Mass Market Coupon Initiative	SeeLine 2006
Third Tranche	Residential	2005 Residential Real Time Monitoring Pilot	Mountain 2006
Third Tranche	Residential	2006 CFL Distributed by HOB	OEB 2008b
Third Tranche	Residential	2006 Fall EKC Program	OPA 2009 and OPA 2006a
Third Tranche	Residential	2006 Holiday Light Exchange	OEB 2008b and SeeLine 2006
Third Tranche	Residential	2006 Spring EKC Program	OPA 2009 and OPA 2006b
Third Tranche	Residential	2007 CFL Distributed by HOB	OEB 2008b
Third Tranche	Residential	2007 EKC Program	OPA 2009 and OEB 2008b
Third Tranche	GS 50 to 699 and GS 700 to 4999	2007 C/I Load Control Program	Trico 2007 and OEB 2008b

1. The sources of SSM inputs were the best available at the onset of the program.

The measure inputs used to calculate SSM and LRAM claims can be found in Table 9 to Table 13 in Appendix A.

Requested SSM amounts

Equipment costs and benefits were calculated by entering the measure assumptions found in Table 9 and Table 10 of Appendix A into IndEco's TRC calculator.[7] The net TRC benefits were then used to calculate SSM entitlements for each year of every program.

SSM amounts were calculated for all third tranche programs, including the 2006 and 2007 EKC programs, for which HOB played a central role, and funded its contribution from third tranche funds.

The program design was changed in 2008 and Hydro One Brampton Network's participation was not integral to the program. Therefore no SSM is claimed on net benefits from the 2008 program.

SSM amounts and TRC benefits net of free riders for all applicable programs are shown in Table 3.

[7] The original spreadsheets used to calculate the TRC values in HOB's annual reports were unavailable. The total TRC benefits calculated by IndEco differed from the total in the annual reports by less than $1,000.

Table 3 – Summary of Net TRC benefits and SSM entitlement

Program	Year	Residential	GS < 50 kW	GS 50 to 699 kW	GS 700 to 4,999 kW	Net TRC	SSM amount
C/I Load Control Program	2005			($1,626)	($8,135)	*($9,761)*	*($488)*
	2006			($464)	($2,323)	*($2,787)*	*($139)*
	2007			$129,832	$649,474	*$779,306*	*$38,965*
CFL Distributed by HOB	2006	$2,865,174				*$2,865,174*	*$143,259*
	2007	$1,048,743				*$1,048,743*	*$52,437*
Commercial & Industrial Technology Demonstration Program	2006		($513)			*($513)*	*($26)*
	2007		$12,101			*$12,101*	*$605*
Common Communication & Education Program	2005	($25,370)				*($25,370)*	*($1,268)*
	2006	($133,677)				*($133,677)*	*($6,684)*
	2007	($88,618)				*($88,618)*	*($4,431)*
Common HOB Internal Efficiency Program	2006			($3,582)		*($3,582)*	*($179)*
	2007			($1,373)		*($1,373)*	*($69)*
Common Research and Planning	2005	($6,729)				*($6,729)*	*($336)*
	2006	($4,483)				*($4,483)*	*($224)*
EKC Program	2007	$1,648,886				$1,648,886	*$82,444*
Fall EKC Program	2006	$1,881,815				$1,881,815	*$94,091*
Spring EKC Program	2006	$955,191				$955,191	*$47,760*
Holiday Light Exchange	2006	$65,661				*$65,661*	*$3,283*
Residential Holiday LED Lighting	2005	$50,600				*$50,600*	*$2,530*
Residential Load Control Program	2005	($66,302)				*($66,302)*	*($3,315)*
Residential Mass Market Coupon Initiative	2005	$239,774				*$239,774*	*$11,989*
Residential Real Time Monitoring Pilot	2005	($31,406)				*($31,406)*	*($1,570)*
	2006	($3,879)				*($3,879)*	*($194)*
Total Net TRC benefits		*$8,395,379*	*$11,588*	*$122,786*	*$639,016*	*$9,168,769*	
Total Net SSM							**$458,438**

Requested LRAM amounts

LRAM calculations are to be completed with the best information available at the time of the third party review. As such, the energy savings indicated in HOB's annual reports for programs in HOB's CDM portfolio were recalculated with the assumptions found in Table 11 to Table 13 in Appendix A.

The energy savings of the following programs were recalculated (from what is reported in the annual reports) to reflect updated LRAM inputs and free-rider rates:

- 2005 Residential Mass Market Coupon Initiative
- 2005 Residential Holiday LED Lighting
- 2006 CFL Distributed by HOB

- 2007 CFL Distributed by HOB
- 2007 C/I Load Control Program

The 2007 C/I Load Control Program includes the measures installed at the Hydro One Brampton Networks' building. These measures were kept at a free-rider rate of 0% as previously discussed. The free-rider rate for the 2005 Residential Real Time Monitoring Pilot also remained at 0%.

Energy savings for measures installed between 2005 and 31 December 2008 were calculated to the end of 2010.

Table 4 shows the energy savings or demand reductions of each program by rate class. OPA program energy savings in Table 4 and LRAM amounts (in Table 7) were acquired directly from spreadsheets provided by the OPA.

Table 4 – Cumulative net program energy savings and demand savings by rate class through 2010

Funding source	Program	Program year	Residential (kWh)	GS < 50 kW (kWh)	GS 50 to 699 kW[1] (kW-mo)	GS 700 to 4,999 kW (kW-mo)
OPA	Cool Savings Rebate	2006	1,251,784			
		2007	3,354,405			
		2008	1,812,146			
	EKC Program	2008	9,940,360			
	Electricity Retrofit Incentive	2008			14,948	12,703
	Great Refrigerator Roundup	2007	952,580			
		2008	1,593,225			
	High Performance New Construction	2008		29,181		
	peaksaver®	2008	55,430			
	Renewable Energy Standard Offer	2008		76,784		
	Summer Savings	2007	9,011,283			
	Summer Sweepstakes	2008	128,824			
OPA net savings by rate class			*28,100,037*	*105,964*	*14,948*	*12,703*
Third Tranche	C/I Load Control Program	2007			3,142	15,719
	CFL Distributed by HOB	2006	18,848,801			
		2007	5,300,747			
	EKC Program[2]	2007	14,537,379			
	Fall EKC Program[2]	2006	24,624,434			
	Residential Holiday LED Lighting	2005	222,835			
	Residential Mass Market Coupon Initiative	2005	1,530,616			
	Residential Real Time Monitoring Pilot	2005	96,264			
	Spring EKC Program	2006	14,889,761			
Third Tranche net savings by rate class			*80,050,837*	*0*	*3,142*	*15,719*
Total net savings per rate class			**108,150,873**	**105,964**	**18,090**	**28,422**
Total net savings			**108,256,837**		**46,512**	

1. Rates for the general service rate class of customers rated at greater than 50kW are on a monthly demand basis (kW), not an energy one (kWh). Lost revenue results when the customer's monthly peak demand is lower than it otherwise would be as a result of the CDM initiatives. These are measured in kW-month, which is the reduction within one month of the peak kilowatt demand. (So a 2 kW-month reduction could be realized by reducing the peak demand in the month by 1 kW for two months, or by 2 kW for one month.) Excluded are peak demand reductions associated with demand response programs which are not anticipated to impact on revenues.

2. The EKC program in 2006 and 2007 was a partnership with the OPA. HOB's financial contribution was funded through it's third-tranche allocation.

Table 5 – Cumulative gross program energy savings and peak demand savings by rate class through 2010

Funding source	Program	Program year	Residential (kWh)	GS < 50 kW (kWh)	GS 50 to 699 kW (kW-month)	GS 700 to 4,999 kW (kW-month)
OPA	Cool Savings Rebate	2006	1,390,871			
		2007	6,385,249			
		2008	3,379,313			
	EKC Program	2008	24,642,957			
	Electricity Retrofit Incentive	2008			14,948	12,703
	Great Refrigerator Roundup	2007	2,363,431			
		2008	2,930,889			
	High Performance New Construction	2008		29,181		
	peaksaver®	2008	61,589			
	Renewable Energy Standard Offer	2008		76,784		
	Summer Savings	2007	75,094,024			
	Summer Sweepstakes	2008	165,159			
OPA gross kWh savings by rate class			*116,413,482*	*105,964*	*14,948*	*12,703*
Third Tranche	C/I Load Control Program	2007			4,291	21,464
	CFL Distributed by HOB	2006	26,926,859			
		2007	7,572,496			
	EKC Program	2007	20,552,682			
	Fall EKC Program	2006	27,360,482			
	Residential Holiday LED Lighting	2005	318,335			
	Residential Mass Market Coupon Initiative	2005	2,186,954			
	Residential Real Time Monitoring Pilot	2005	96,264			
	Spring EKC Program	2006	16,544,179			
Third Tranche gross kWh savings by rate class			*101,557,891*	*0*	*4,291*	*21,464*
Total gross savings per rate class			**217,971,373**	**105,964**	**19,239**	**34,167**
Total gross savings			**218,077,337**		**53,406**	

Energy savings were converted to LRAM values by using HOB distribution rates. Distribution rates are in Table 6.

Table 6 – Distribution rates per rate class

Rate Class	Units	2005	2006	2007	2008	2009	2010
Residential	$/kWh	0.0157	0.0158	0.0159	0.0157	0.0157	0.0154
GS < 50 kW	$/kWh	0.0182	0.0182	0.0183	0.0181	0.0181	0.0178
GS 50 to 699 kW	$/kW/month	2.3206	2.3508	2.3593	2.3333	2.3354	2.2935
GS 700 to 4,999 kW	$/kW/month	3.6954	3.8288	3.8426	3.8003	3.8037	3.7355

The LRAM is presented in Table 7

Table 7 – Summary of requested LRAM amounts in 2011$[1]

Funding source	Program	Year	Residential	GS < 50 kW	GS 50 to 699 kW	GS 700 to 4,999 kW	*6-year LRAM*
OPA	Cool Savings Rebate	2006	$20,739	$0	$0	$0	*$20,739*
		2007	$54,447	$0	$0	$0	*$54,447*
		2008	$28,781	$0	$0	$0	*$28,781*
	EKC Program	2008	$157,880	$0	$0	$0	*$157,880*
	Electricity Retrofit Incentive	2008	$0	$0	$35,317	$48,881	*$84,198*
	Great Refrigerator Roundup	2007	$15,462	$0	$0	$0	*$15,462*
		2008	$25,304	$0	$0	$0	*$25,304*
	High Performance New Construction	2008	$0	$535	$0	$0	*$535*
	peaksaver®	2008	$880	$0	$0	$0	*$880*
	Renewable Energy Standard Offer	2008	$0	$1,407	$0	$0	*$1,407*
	Summer Savings	2007	$151,411	$0	$0	$0	*$151,411*
	Summer Sweepstakes	2008	$2,103	$0	$0	$0	*$2,103*
OPA total			*$457,005*	*$1,942*	*$35,317*	*$48,881*	*$543,145*
Third Tranche	C/I Load Control Program	2007	$0	$0	$7,507	$61,167	*$68,674*
	CFL Distributed by HOB	2006	$309,193	$0	$0	$0	*$309,193*
		2007	$85,159	$0	$0	$0	*$85,159*
	EKC Program	2007	$236,008	$0	$0	$0	*$236,008*
	Fall EKC Program	2006	$413,505	$0	$0	$0	*$413,505*
	Spring EKC Program	2006	$250,423	$0	$0	$0	*$250,423*
	Residential Holiday LED Lighting	2005	$3,764	$0	$0	$0	*$3,764*
	Residential Mass Market Coupon Initiative	2005	$25,657	$0	$0	$0	*$25,657*
	Residential Real Time Monitoring Pilot	2005	$1,631	$0	$0	$0	*$1,631*
Third tranche total			*$1,325,340*	*$0*	*$7,507*	*$61,167*	*$1,394,014*
Total			*$1,782,345*	*$1,942*	*$42,824*	*$110,048*	**$1,937,159**

1. LRAM amounts by program and program year, and program totals are for energy (or demand) reductions for the years 2005 through 2010.

Findings

The fifteen third tranche programs in HOB's CDM portfolio were completed as of December 31, 2007. Although the OEB guidance for this report asks for comments on future program evaluation and improvements to program performance, this expectation is not relevant for these programs that have ended and are not expected to be reinitiated.

IndEco has reviewed the input values and custom project justifications used to calculate the energy savings and net TRC benefits resulting from HOB's portfolio as well as those associated with 2006, 2007 and 2008 OPA-funded programs.

IndEco has concluded that sufficient detail and documentation exists to recommend increasing Hydro One Brampton Networks' distribution rates in order to collect $1,937,159 in LRAM and $458,438 in SSM amounts, allocated by rate class as shown in Table 8.

Table 8 – LRAM and SSM amounts by rate class in 2011$

Rate class	LRAM	SSM
Residential	$1,782,345	$419,769
GS < 50 kW	$1,942	$579
GS 50 to 699 kW	$42,824	$6,139
GS 700 to 4,999 kW	$110,048	$31,951
Large Use	$0	$0
Unmetered Scattered Load	$0	$0
Standby Power	$0	$0
Sentinel Lighting	$0	$0
Street Lighting	$0	$0
Embedded Distributor	$0	$0
Total	**$1,937,159**	**$458,438**

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Appendix A. Inputs used for TRC and energy savings calculations

Table 9 - SSM inputs and contribution to the total SSM for all residential rate class measures.

Program	Energy Efficiency Measure	Number of units	Measure life	Measure cost	SSM Free Ridership	Total benefits ($)	Total costs ($)	Annual operating hours	Annual energy savings (kWh/yr)	Contribution to SSM
2005 Residential Holiday LED Lighting	LED Holiday Lights 5W	4,027	30.00	$2.00	10%	$90,413	$8,054	Not used	19.0	$3,706
	LED Holiday Lights Mini	1,926	30.00	$2.00	10%	$15,993	$3,852	Not used	7.0	$546
2005 Residential Mass Market Coupon Initiative	Programmable Thermostat - Space Heating	70	18.00	$60.00	10%	$81,848	$4,200	Not used	1,472.8	$3,494
	Compact Fluorescent Lights	3,729	4.00	$2.00	10%	$96,836	$7,458	Not used	104.4	$4,022
	Outdoor Timer	200	20.00	$20.00	10%	$48,512	$4,000	Not used	292.0	$2,003
	Seasonal LED-5W	853	30.00	$2.00	10%	$35,144	$1,706	Not used	44.5	$1,505
	Programmable Thermostat - Space Cooling	183	18.00	$60.00	10%	$40,300	$10,980	Not used	159.1	$1,319
	Seasonal Minis	853	30.00	$2.00	10%	$13,426	$1,706	Not used	17.0	$527
	Indoor Timer AC	31	20.00	$7.00	10%	$6,004	$217	Not used	108.8	$260
	Indoor Timer Lights	32	20.00	$7.00	10%	$3,774	$224	Not used	98.1	$160
	Ceiling Fan	51	20.00	$42.00	10%	$0	$2,142	Not used	0.0	($96)
2005 Residential Real Time Monitoring Pilot[2]	Installation of a Real-Time Monitor	21	5.00	$0	0%	$5,027	$0	Not used	764.0	$251
2006 CFL Distributed by HOB	15 W CFL	134,921	4.00	$2.00	10%	$3,503,687	$269,842	Not used	104.4	$145,523
2006 Fall EKC Program	Energy Star® Compact Fluorescent Light	52,985	4.00	$1.62	10%	$1,370,665	$85,836	Not used	104.4	$57,817

Program	Energy Efficiency Measure	Number of units	Measure life	Measure cost	SSM Free Ridership	Total benefits ($)	Total costs ($)	Annual operating hours	Annual energy savings (kWh/yr)	Contribution to SSM
	Bulb									
	Programmable Thermostats	841	18.00	$25.00	10%	$440,075	$21,025	Not used	522.1	$18,857
	Seasonal Light Emitting Diode Light String	12,753	30.00	$8.70	10%	$366,025	$110,951	Not used	30.8	$11,478
	Programmable Baseboard Thermostats	50	18.00	$25.00	10%	$58,193	$1,250	Not used	1,466.3	$2,562
	Dimmers	665	10.00	$13.00	10%	$46,940	$8,645	Not used	139.0	$1,723
	Indoor Motion Sensors	239	20.00	$20.00	10%	$41,494	$4,780	Not used	209.0	$1,652
2006 Holiday Light Exchange	LED Holiday Lights 5W	3,183	30	$2.00	10%	$71,463	$6,366	Not used	19.0	$2,929
	LED Holiday Lights Mini	3,183	30	$2.00	10%	$26,430	$6,366	Not used	7.0	$903
2006 Spring EKC Program	Energy Star® Compact Fluorescent Light Bulb	35,735	4.00	$2.50	10%	$927,982	$89,338	Not used	104.4	$89,338
	Electric Timers	1,002	20.00	$12.50	10%	$152,320	$12,525	Not used	183.0	$12,525
	Programmable Thermostats	436	15.00	$65.00	10%	$77,813	$28,340	Not used	216.0	$28,340
	Energy Star® Ceiling Fans	332	20.00	$25.00	10%	$41,710	$8,300	Not used	141.0	$8,300
2007 CFL Distributed by HOB	15 W CFL	48,784	4.00	$2.00	10%	$1,266,202	$97,568	Not used	104.4	$52,589
2007 EKC Program	15 W CFL	65,999	8.00	$2.00	10%	$1,303,418	$131,998	Not used	43.0	$52,714
	20 W+ CFLs	10,744	8.00	$0.86	10%	$306,541	$9,213	Not used	62.1	$13,380
	Project Porchlight CFLs	13,888	8.00	$2.00	10%	$274,275	$27,776	Not used	43.0	$11,092

Program	Energy Efficiency Measure	Number of units	Measure life	Measure cost	SSM Free Ridership	Total benefits ($)	Total costs ($)	Annual operating hours	Annual energy savings (kWh/yr)	Contribution to SSM
	Lighting Control Devices	2,715	10.00	$20.80	10%	$126,570	$56,472	Not used	72.2	$3,154
	Outdoor Motion Sensor	848	10.00	$16.20	10%	$70,500	$13,738	Not used	159.8	$2,554
	Energy Star Light Fixtures	256	16.00	$24.00	10%	$24,808	$6,144	Not used	122.9	$840
	Programmable Thermostat	518	15.00	$25.00	10%	$28,238	$12,950	Not used	75.1	$688
	Solar Lights	8,473	5.00	$4.75	10%	$79,957	$40,247	Not used	32.8	$1,787
	T8	502	18.00	$20.00	10%	$15,719	$10,040	Not used	37.2	$256
	Power Bar with Timer	234	10.00	$25.00	10%	$9,536	$5,850	Not used	72.4	$166
	Energy Star Ceiling Fan	532	10.00	$47.00	10%	$26,146	$25,004	Not used	89.8	$51
	Dimmer Switch	539	10.00	$13.00	10%	$7,053	$7,007	Not used	23.7	$2
	Furnace Filter	2,145	1.00	$12.00	10%	$5,468	$25,740	Not used	37.7	($912)
	SLEDs	17,486	5.00	$8.70	10%	$78,173	$152,128	Not used	13.7	($3,328)
Total contribution to SSM claim										**$443,937**

1. Annual operating hours are not used when both the measure life and annual kWh energy savings are available.
2. The equipment costs for the 2005 Residential Real Time Monitoring Pilot are included in the program utility costs.

Table 10 - SSM inputs and contribution to the total SSM for the 2007 C/I Load Reduction program.[1]

Energy Efficiency Measure	Number of units	Measure life[2]	Measure cost	SSM Free Ridership	Total benefits ($)	Total costs ($)[3]	Annual operating hours	Annual energy savings (kWh/yr)	Contribution to SSM
8 lamp T8	704	8.66	$65.00	10%	$593,380	$45,760	5,777	1,320.5	$24,643
4 lamp T5	542	8.05	$436.00	10%	$452,232	$236,312	6,211	1,396.9	$9,716
6 lamp T8	150	19.29	$65.00	10%	$109,212	$9,750	2,592	589.3	$4,476
8 lamp T5	40	8.05	$436.00	10%	$103,138	$17,440	6,211	4,316.8	$3,856
T8s and T6s	30	7.44	$65.00	10%	$86,711	$1,950	6,717	5,205.4	$3,814
2' x 4' fixture with 2 LP T8 28-watt UMX cover-guard lamps	290	5.71	$53.00	10%	$73,955	$15,370	8,760	586.9	$2,636
4 lamp T5	121	8.79	$436.00	10%	$90,866	$52,756	5,689	1,160.5	$1,715
6 lamp T8 Warehouse	46	8.06	$65.00	10%	$39,558	$2,990	6,200	1,438.4	$1,646
4 x 54 watt T5 fluorescent	81	5.71	$436.00	10%	$69,677	$35,316	8,760	1,979.8	$1,546
T8 lamp	102	7.60	$36.00	10%	$37,991	$3,672	6,577	657.7	$1,544
4 lamp T8	178	20.17	$65.00	10%	$38,076	$11,570	2,479	168.5	$1,193
New 4 lamp F54TfHO Industrial without sensor	52	5.71	$436.00	10%	$43,543	$22,672	8,760	1,927.2	$939
New 4 lamp F54TfHO Industrial without sensor	65	5.71	$436.00	10%	$42,801	$28,340	8,760	1,515.5	$651
1' x 4' fixture with 2 - 4' 28 watt UMX cover guard lamps LBF 34 volt	651	5.71	$53.00	10%	$47,079	$34,503	8,760	166.4	$566
MB-509DL	134	6.87	$4.00	10%	$12,367	$536	3,640	163.8	$532
400 watt MH	28	19.33	$436.00	10%	$21,234	$12,208	2,586	613.0	$406
T8 lamp	113	7.60	$36.00	10%	$12,079	$4,068	6,577	188.8	$360
Garden Centre lights	48	6.06	$65.00	10%	$10,021	$3,120	5,777	439.0	$311
MB-509DL	67	6.87	$4.00	10%	$7,145	$268	3,640	189.3	$309
T12 - 2 lamp 8FT.	83	19.33	$53.00	10%	$10,623	$4,399	2,586	103.5	$280
Night lights	10	4.00	$65.00	10%	$6,427	$650	8,760	2,002.5	$260
1' x 4' fixture with 2 - 4' 8 watt T8 UMX lamps LBF 120 volt	232	5.71	$53.00	10%	$16,778	$12,296	8,760	166.4	$202

Energy Efficiency Measure	Number of units	Measure life[2]	Measure cost	SSM Free Ridership	Total benefits ($)	Total costs ($)[3]	Annual operating hours	Annual energy savings (kWh/yr)	Contribution to SSM
6 lamp T8 Warehouse	5	8.06	$65.00	10%	$4,300	$325	6,200	1,438.4	$179
T8-8'-2lamp	16	12.90	$53.00	10%	$4,577	$848	3,875	317.2	$168
2 - 1' x 4' 2LP fixtures with 4 - T8 XP Lps Tan CVG LP 347 Volt High	192	5.71	$53.00	10%	$13,885	$10,176	8,760	166.4	$167
2 - 2LP 1' x 4' fixtures Tandem 4 T8 28 watt UMX lamps LBF 120 Volt	156	5.71	$53.00	10%	$11,282	$8,268	8,760	166.4	$136
T8-4'-4lamp	14	12.90	$65.00	10%	$3,474	$910	3,875	275.1	$115
2' x 4' fixture with 4 LP T8 28-watt UMX CVG lamps LP 347 volt	18	5.71	$53.00	10%	$2,398	$954	8,760	306.6	$65
2 - 1' x 4' 2LP fixtures with 4 - T8 XP Lps CVG Tan LP 347 Volt	48	5.71	$53.00	10%	$3,471	$2,544	8,760	166.4	$42
Relamp with LED screw-in lamps	30	4.00	$50.43	10%	$2,362	$1,513	8,760	245.3	$38
T8-4'-2lamp	17	12.90	$53.00	10%	$1,616	$901	3,875	105.4	$32
2' x 2' fixture with 2 - 4' T8 U6" Lps Volt LP	35	5.71	$53.00	10%	$2,531	$1,855	8,760	166.4	$30
CFL 13W	16	1.52	$4.00	10%	$642	$64	6,577	309.1	$26
LEDs	15	5.32	$50.43	10%	$1,180	$756	6,577	187.5	$19
T12 - 2 lamp 4 FT.	35	19.33	$53.00	10%	$2,240	$1,855	2,586	51.7	$17
F28T8	5	7.60	$65.00	10%	$577	$325	6,577	203.9	$11
CFL 20W	5	1.52	$4.00	10%	$235	$20	6,577	361.8	$10
CFL 13W	4	2.58	$4.00	10%	$168	$16	3,875	182.1	$7
CFL 7W	3	2.58	$5.00	10%	$142	$15	3,875	205.4	$6
CFL 4W	2	2.58	$5.00	10%	$47	$10	3,875	100.8	$2
CFL 48W	1	2.58	$75.00	10%	$32	$75	3,875	139.5	($2)
2x4 T8 - a2	241	16.03	$65.00	0%	$31,554	$0	3,120	122.0	$1,578
Stores - M2	34	10.00	$0.00	0%	$22,126	$0	4,160	876.0	$1,106
1st Floor - U1	287	16.03	$53.00	0%	$18,306	$0	3,120	59.4	$915

Energy Efficiency Measure	Number of units	Measure life[2]	Measure cost	SSM Free Ridership	Total benefits ($)	Total costs ($)[3]	Annual operating hours	Annual energy savings (kWh/yr)	Contribution to SSM
2x4 Basement - A2	100	16.03	$65.00	0%	$13,093	$0	3,120	122.0	$655
SubStation maint - M2	25	10.00	$0.00	0%	$12,751	$0	3,120	657.0	$638
Outside truck park - M2	18	10.00	$0.00	0%	$12,220	$0	4,368	919.8	$611
Truck Area - M4	38	5.72	$175.00	0%	$11,588	$0	8,736	700.8	$579
New Fixtures - U2	16	16.03	$53.00	0%	$8,970	$0	3,120	522.5	$449
Truck Area - B2	36	16.03	$65.00	0%	$8,460	$0	3,120	219.0	$423
2x2 U Tubes - U1	125	16.03	$53.00	0%	$7,973	$0	3,120	59.4	$399
Offices - a2	58	16.03	$65.00	0%	$7,594	$0	3,120	122.0	$380
Child Development - A2	55	16.03	$65.00	0%	$7,201	$0	3,120	122.0	$360
Truck Storage - M4	20	5.72	$175.00	0%	$6,099	$0	8,736	700.8	$305
2x2 u tubes - U1	66	16.03	$53.00	0%	$4,210	$0	3,120	59.4	$210
2x4 Basement - B1	32	16.03	$53.00	0%	$4,190	$0	3,120	122.0	$209
Office High ceiling - M1	8	16.03	$65.00	0%	$4,136	$0	3,120	481.8	$207
New Fixtures - b2	16	16.03	$65.00	0%	$3,760	$0	3,120	219.0	$188
Control Room - C1	30	5.72	$53.00	0%	$3,576	$0	8,736	227.8	$179
Roy Taylor - S1	1	10.00	$0.00	0%	$3,271	$0	2,080	3,879.4	$164
Front Lobby - G1	23	9.62	$4.00	0%	$3,098	$0	1,040	132.4	$155
Storage - B2	13	16.03	$65.00	0%	$3,055	$0	3,120	219.0	$153
Meeting a - S1	1	10.00	$0.00	0%	$2,726	$0	2,080	3,232.9	$136
2x2 U Tubes - U1	32	16.03	$53.00	0%	$2,041	$0	3,120	59.4	$102
Receiving - M2	4	10.00	$0.00	0%	$2,040	$0	3,120	657.0	$102
Computer Room - U1	28	16.03	$53.00	0%	$1,786	$0	3,120	59.4	$89
2x2 utube hall - U1	27	16.03	$53.00	0%	$1,722	$0	3,120	59.4	$86
Office - s1	1	24.04	$0.00	0%	$1,561	$0	2,080	1,188.9	$78
Human Resources - U1	23	16.03	$53.00	0%	$1,467	$0	3,120	59.4	$73
1x4 Truck area - B1	11	16.03	$53.00	0%	$1,440	$0	3,120	122.0	$72

Energy Efficiency Measure	Number of units	Measure life[2]	Measure cost	SSM Free Ridership	Total benefits ($)	Total costs ($)[3]	Annual operating hours	Annual energy savings (kWh/yr)	Contribution to SSM
Stairwell - G1	10	6.41	$4.00	0%	$1,293	$0	1,560	198.7	$65
Cafeteria - U1	15	16.03	$53.00	0%	$957	$0	3,120	59.4	$48
u tube sensor - U1	30	48.08	$53.00	0%	$944	$0	1,040	19.8	$47
Foreman - A1	5	16.03	$53.00	0%	$940	$0	3,120	175.2	$47
Womens - S1	1	10.00	$0.00	0%	$872	$0	2,080	1,034.5	$44
Meeting a - U1	25	48.08	$53.00	0%	$786	$0	1,040	19.8	$39
Offices - U1	12	16.03	$53.00	0%	$765	$0	3,120	59.4	$38
Mens - S1	1	10.00	$0.00	0%	$763	$0	2,080	905.2	$38
Womens - S1	1	10.00	$0.00	0%	$763	$0	2,080	905.2	$38
Mens - S1	1	10.00	$0.00	0%	$763	$0	2,080	905.2	$38
Hall - a2	5	8.01	$65.00	0%	$725	$0	6,240	244.0	$36
Womens - B1	8	32.05	$53.00	0%	$685	$0	1,560	61.0	$34
Mens - B1	7	32.05	$53.00	0%	$600	$0	1,560	61.0	$30
Womens - b1	7	32.05	$53.00	0%	$600	$0	1,560	61.0	$30
Mens - B1	7	32.05	$53.00	0%	$600	$0	1,560	61.0	$30
Project - U1	9	16.03	$53.00	0%	$574	$0	3,120	59.4	$29
New Fixtures - b1	4	16.03	$53.00	0%	$524	$0	3,120	122.0	$26
Print Room - U1	8	16.03	$53.00	0%	$510	$0	3,120	59.4	$26
Hall - u1	8	16.03	$53.00	0%	$510	$0	3,120	59.4	$26
Health & Safety - U1	6	16.03	$53.00	0%	$383	$0	3,120	59.4	$19
Office - a2	5	48.08	$65.00	0%	$323	$0	1,040	40.7	$16
Cal Struthers - U1	4	16.03	$53.00	0%	$255	$0	3,120	59.4	$13
2x2 utube hall - a1	1	5.72	$53.00	0%	$213	$0	8,736	490.6	$11
New fixtures – NF	2	16.03	$53.00	0%	($752)	$0	3,120	-350.4	($38)
on order – NF	6	12.02	$53.00	0%	($2,384)	$0	4,160	-467.2	($119)
T5 Complete – NF	18	11.45	$436.00	0%	($7,204)	$0	4,368	-490.6	($360)

Energy Efficiency Measure	Number of units	Measure life[2]	Measure cost	SSM Free Ridership	Total benefits ($)	Total costs ($)[3]	Annual operating hours	Annual energy savings (kWh/yr)	Contribution to SSM
New Fixtures - M3	14	16.03	$175.00	0%	($10,340)	$0	3,120	-688.3	($517)
on order - M3	16	12.02	$175.00	0%	($12,486)	$0	4,160	-917.7	($624)
Total contribution to SSM claim									**$72,380**

1. The 2007 C/I Load Reduction program is split 17% and 83% across the GS 50 to 699 kW and the GS 700 to 4999 kW rate classes, respectively. The requested SSM amount is divided according to the same split.

2. Measure life is calculated by dividing the useful lifetime in hours (as provided by OPA 2010b by the annual operating hours (provided by Trico 2007). For T8 and T5s, the lifetime of the ballast was used (50,000 hours).

3. The measures whose total costs are listed as $0 are measure installed as part of the HOB internal retrofit. Their costs are included in the program utility costs.

The total equipment contribution to the SSM as given in Table 9 and Table 10 is $516,317. The total utility cost for all programs is $1,157,574. These costs contribute ($57,879) to the total SSM. Combining these two contributions to the SSM gives the requested amount of $458,438.

Table 11 – LRAM inputs and contribution to the total LRAM for all residential rate class measures.

Program	Energy Efficiency Measure	Number of units	Measure life	LRAM Free Ridership	Annual energy savings (kWh/yr)	Annual demand savings (kW/yr)	Contribution to LRAM (2011$)	Assumption Source
2005 Residential Holiday LED Lighting	LED Holiday Lights 5W	4,027	5.0	30%	13.5	0.00	$3,214	OPA 2010a
	LED Holiday Lights Mini	1,926	5.0	30%	4.8	0.00	$550	OPA 2010a
2005 Residential Mass Market Coupon Initiative	15 W Compact Fluorescent Lights	3,729	8.0	30%	44.4	0.00	$10,670	OPA 2010a
	Programmable Thermostat - Space Heating	70	11.0	30%	2151.0	0.18	$9,715	OPA 2010a
	Programmable Thermostat - Space Cooling	183	11.0	30%	203.0	0.18	$2,397	OPA 2010a
	Outdoor Timer	200	10.0	30%	68.1	0.00	$878	OPA 2010a
	Seasonal LED-5W	853	5.0	30%	13.5	0.00	$681	OPA 2010a
	Indoor Timer Lights	32	10.0	30%	219.0	0.01	$452	OPA 2010a
	Ceiling Fan	51	10.0	30%	122.6	0.00	$403	OPA 2010a
	Seasonal Minis	853	5.0	30%	4.8	0.00	$244	OPA 2010a
	Indoor Timer AC	31	20.0	30%	108.8	0.17	$218	SeeLine 2006
2005 Residential Real Time Monitoring Pilot	Installation of a Real-Time Monitor	21	30.0	0%	764.0	0.09	$1,631	Mountain 2006
2006 CFL Distributed by HOB	15 W CFL	134,921	8.0	30%	44.4	0.00	$309,193	OPA 2010a
2006 Cool Savings Rebate	Energy Star® Air Conditioner	384	14.0	10%	351.0	0.36	$10,057	OPA 2009
	Air Conditioner Tune-Up	262	8.0	10%	369.0	0.04	$7,211	OPA 2009
	Programmable Thermostats	293	18.0	10%	159.0	0.16	$3,471	OPA 2009
2006 Fall EKC Program	Energy Star® Compact Fluorescent Light Bulb	52,985	4.0	10%	104.4	0.00	$335,466	OPA 2009
	Programmable Thermostats	841	18.0	10%	522.1	0.12	$32,723	OPA 2009
	Seasonal Light Emitting Diode Light String	12,753	30.0	10%	30.8	0.00	$29,237	OPA 2009
	Dimmers	665	10.0	10%	139.0	0.00	$6,889	OPA 2009
	Programmable Baseboard Thermostats	50	18.0	10%	1466.3	0.00	$5,474	OPA 2009
	Indoor Motion Sensors	239	20.0	10%	209.0	0.00	$3,717	OPA 2009
2006 Spring EKC	Energy Star® Compact Fluorescent Light Bulb	35,735	4.0	10%	104.4	0.00	$226,252	OPA 2009

Program	Energy Efficiency Measure	Number of units	Measure life	LRAM Free Ridership	Annual energy savings (kWh/yr)	Annual demand savings (kW/yr)	Contribution to LRAM (2011$)	Assumption Source
Program	Electric Timers	1,002	20.0	10%	183.0	0.00	$13,668	OPA 2009
	Programmable Thermostats	436	15.0	10%	216.0	0.05	$7,018	OPA 2009
	Energy Star® Ceiling Fans	332	20.0	10%	141.0	0.01	$3,485	OPA 2009
2007 CFL Distributed by HOB	15 W CFL	48,784	8.0	30%	44.4	0.00	$85,159	OPA 2010a
2007 Cool Savings Rebate	Furnace with Electronically Commutated Motor	1,444	15.0	46%	831.9	0.49	$46,095	OPA 2009
	ENERGY STAR® Central Air Conditioner	922	18.0	48%	152.2	0.17	$5,209	OPA 2009
	Central Air Conditioning Tune Up	779	5.0	58%	235.5	0.26	$1,872	OPA 2009
	Programmable Thermostat	1,305	15.0	54%	54.6	0.03	$1,271	OPA 2009
2007 EKC Program	15 W CFL	65,999	8.0	22%	43.0	0.00	$143,720	OPA 2009
	20 W+ CFLs	10,744	8.0	22%	62.1	0.00	$33,789	OPA 2009
	Project Porchlight CFLs	13,888	8.0	24%	43.0	0.00	$29,468	OPA 2009
	SLEDs	17,486	5.0	51%	13.7	0.00	$7,621	OPA 2009
	Lighting Control Devices	2,715	10.0	45%	72.2	0.02	$7,000	OPA 2009
	Outdoor Motion Sensor	848	10.0	45%	159.8	0.00	$4,837	OPA 2009
	Solar Lights	8,473	5.0	87%	32.8	0.00	$2,346	OPA 2009
	Energy Star Ceiling Fan	532	10.0	45%	89.8	0.00	$1,707	OPA 2009
	Programmable Thermostat	518	15.0	45%	75.1	0.00	$1,388	OPA 2009
	Energy Star Light Fixtures	256	16.0	45%	122.9	0.01	$1,125	OPA 2009
	T8	502	18.0	23%	37.2	0.00	$934	OPA 2009
	Power Bar with Timer	234	10.0	23%	72.4	0.01	$849	OPA 2009
	Furnace Filter	2,145	1.0	45%	37.7	0.01	$769	OPA 2009
	Dimmer Switch	539	10.0	45%	23.7	0.00	$456	OPA 2009
2007 Great Refrigerator Roundup	Refrigerator	632	9.0	52%	744.7	0.07	$11,974	OPA 2009
	Freezer	214	8.0	50%	515.4	0.07	$3,271	OPA 2009
	Small Refrigerator	10	9.0	62%	490.0	0.05	$96	OPA 2009

Program	Energy Efficiency Measure	Number of units	Measure life	LRAM Free Ridership	Annual energy savings (kWh/yr)	Annual demand savings (kW/yr)	Contribution to LRAM (2011$)	Assumption Source
	Window Air Conditioner	11	5.0	57%	240.2	0.56	$74	OPA 2009
	Small Freezer	7	8.0	62%	338.5	0.04	$46	OPA 2009
2007 Summer Savings	Household	47,729	2.0	88%	786.7	0.44	$151,411	OPA 2009
2008 Cool Savings Rebate	2008 Efficient Furnace with Electronically Commutable Motor	928	18.0	46%	819.2	0.49	$19,630	OPA 2009
	2007 Efficient Furnace with Electronically Commutable Motor	259	15.0	46%	836.7	0.50	$5,598	OPA 2009
	2008 ENERGYSTAR® Central Air Conditioner	615	18.0	48%	125.3	0.14	$1,909	OPA 2009
	2008 Programmable Thermostat	788	18.0	54%	53.7	0.03	$928	OPA 2009
	2007 ENERGYSTAR® Central Air Conditioner	124	18.0	48%	155.3	0.17	$479	OPA 2009
	2007 Programmable Thermostat	202	15.0	54%	53.7	0.03	$237	OPA 2009
	2007 Central Air Conditioner Tune-ups	0	5.0	84%	235.0	0.26	$0	OPA 2009
2008 EKC Program	Energy Star® Qualified Light Fixtures	18,402	16.0	67%	133.5	0.00	$39,058	OPA 2009
	Energy Star® Qualified Compact Fluorescent Light Bulbs	25,281	8.0	48%	53.0	0.00	$33,335	OPA 2009
	ENERGY STAR Decorative CFLs	42,709	4.0	61%	30.4	0.00	$23,841	OPA 2009
	Pipe Wrap	23,583	6.0	53%	38.0	0.00	$19,993	OPA 2009
	Energy Star® Qualified Compact Fluorescent Floods (Indoor & Outdoor)	11,858	7.0	63%	87.6	0.00	$18,547	OPA 2009
	Lighting Control Devices	3,599	10.0	55%	102.2	0.00	$7,952	OPA 2009
	ENERGY STAR Dimmable CFLs	2,753	6.0	62%	97.8	0.00	$4,833	OPA 2009
	Rewards for Recycling – Dehumidifier	221	12.0	56%	499.8	0.29	$2,315	OPA 2009
	Heavy Duty Timers	417	10.0	67%	301.2	0.02	$1,989	OPA 2009
	T8 Fluorescent Fixtures	3,348	16.0	67%	37.2	0.00	$1,949	OPA 2009
	Programmable Thermostats - Baseboard	1,161	15.0	53%	63.7	0.00	$1,638	OPA 2009
	Rewards for Recycling - Halogen Lamp	191	16.0	52%	275.2	0.01	$1,199	OPA 2009
	Rewards for Recycling – Room Air Conditioner	239	9.0	56%	140.7	0.14	$704	OPA 2009

Program	Energy Efficiency Measure	Number of units	Measure life	LRAM Free Ridership	Annual energy savings (kWh/yr)	Annual demand savings (kW/yr)	Contribution to LRAM (2011$)	Assumption Source
	Air Conditioner/Furnace Filters	1,093	1.0	65%	37.7	0.02	$236	OPA 2009
	Power Bars with Timers	197	10.0	59%	53.3	0.00	$204	OPA 2009
	Keep Cool – Dehumidifier	7	12.0	65%	499.8	0.29	$61	OPA 2009
	Keep Cool – Room Air Conditioner	8	9.0	58%	140.7	0.14	$23	OPA 2009
	Car block heater timer	0		100%	0.0	0.00	$0	OPA 2009
	Awnings	794		100%	0.0	0.00	$0	OPA 2009
	Window Films	12,806		100%	0.0	0.00	$0	OPA 2009
	Electric Water Heater Blankets	393		100%	0.0	0.00	$0	OPA 2009
	Low-Flow Toilets	3,085		100%	0.0	0.00	$0	OPA 2009
2008 Great Refrigerator Roundup	Refrigerator	997	9.0	45%	775.0	0.08	$20,248	OPA 2009
	Freezer	275	8.0	48%	740.0	0.08	$5,042	OPA 2009
	Room Air Conditioner	4	4.5	64%	197.0	0.20	$14	OPA 2009
2008 peaksaver®	Residential Air Conditioner Switch	1,089	13.0	10%	17.3	0.87	$808	OPA 2009
	Residential Programmable Thermostat	97	13.0	10%	17.3	0.87	$72	OPA 2009
	Residential Water Heater Switch	2	13.0	10%	6.0	0.30	$1	OPA 2009
	Commercial Programmable Thermostat	0	13.0	10%	74.0	3.70	$0	OPA 2009
	Commercial Air Conditioner Switch	0	13.0	10%	74.0	3.70	$0	OPA 2009
	Commercial Water Heater Switch	0	13.0	10%	37.0	1.85	$0	OPA 2009
2008 Summer Sweepstakes	Households	215	1.0	22%	768.2	0.20	$2,103	OPA 2009
Total							**$1,782,345**	

Table 12 – LRAM inputs and contribution to total LRAM for all GS < 50 kW rate class measures.

Program	Energy Efficiency Measure	Number of units	Measure life	LRAM Free Ridership	Annual energy savings (kWh/yr)	Annual demand savings (kW/yr)	Contribution to LRAM (2011$)	Assumption Source
2008 High Performance New Construction	Custom New Construction Project	1	14.00	0%	9,727	11.52	$535	OPA 2009
2008 Renewable Energy Standard Offer	Solar Photo-Voltaic	2	20.00	0%	12,797	11.24	$1,407	OPA 2009
	Hydro	0	20.00	0%	0	0	$0	OPA 2009
	Wind	0	20.00	0%	0	0	$0	OPA 2009
	Bio-Energy	0	20.00	0%	0	0	$0	OPA 2009
Total							**$1,942**	

Table 13 - LRAM inputs and contribution to the total LRAM for all GS 50 to 699 and GS 700 to 4999 rate class measures.[1]

Program	Energy Efficiency Measure	Number of units	Measure life	LRAM Free Ridership	Annual energy savings (kWh/yr)	Annual demand savings (kW/yr)	Contribution to LRAM (2011$)
2007 C/I Load Control Program[2]	8 lamp T8	704	8.66	30%	1,321	0.23	$17,226
	4 lamp T5	542	8.05	30%	1,397	0.22	$13,048
	6 lamp T8	150	19.29	30%	589	0.23	$3,651
	8 lamp T5	40	8.05	30%	4,317	0.70	$2,976
	4 lamp T5	121	8.79	30%	1,161	0.20	$2,642
	T8s and T6s	30	7.44	30%	5,205	0.78	$2,489
	2' x 4' fixture with 2 LP T8 28-watt UMX cover-guard lamps	290	5.71	30%	587	0.07	$2,080
	4 x 54 watt T5 fluorescent	81	5.71	30%	1,980	0.23	$1,959
	2x4 T8 - a2	241	16.03	0%	122	0.04	$1,437
	1' x 4' fixture with 2 - 4' 28 watt UMX cover guard lamps LBF 34 volt	651	5.71	30%	166	0.02	$1,324
	4 lamp T8	178	20.17	30%	169	0.07	$1,296
	New 4 lamp F54TfHO Industrial without sensor	52	5.71	30%	1,927	0.22	$1,225
	New 4 lamp F54TfHO Industrial without sensor	65	5.71	30%	1,515	0.17	$1,204
	6 lamp T8 Warehouse	46	8.06	30%	1,438	0.23	$1,142
	Stores - M2	34	10.00	0%	876	0.21	$1,092
	T8 lamp	102	7.60	30%	658	0.10	$1,092
	1st Floor - U1	287	16.03	0%	59	0.02	$834
	SubStation maint - M2	25	10.00	0%	657	0.21	$803
	400 watt MH	28	19.33	30%	613	0.24	$710
	MB-509DL	134	6.87	30%	164	0.05	$645
	2x4 Basement - A2	100	16.03	0%	122	0.04	$596
	Outside truck park - M2	18	10.00	0%	920	0.21	$578
	1' x 4' fixture with 2 - 4' 8 watt T8 UMX	232	5.71	30%	166	0.02	$472

Program	Energy Efficiency Measure	Number of units	Measure life	LRAM Free Ridership	Annual energy savings (kWh/yr)	Annual demand savings (kW/yr)	Contribution to LRAM (2011$)
	lamps LBF 120 volt						
	Truck Area - M4	38	5.72	0%	701	0.08	$465
	Front Lobby - G1	23	9.62	0%	132	0.13	$447
	New Fixtures - U2	16	16.03	0%	522	0.17	$409
	2 - 1' x 4' 2LP fixtures with 4 - T8 XP Lps Tan CVG LP 347 Volt High	192	5.71	30%	166	0.02	$390
	Garden Centre lights	48	6.06	30%	439	0.08	$390
	Truck Area - B2	36	16.03	0%	219	0.07	$385
	MB-509DL	67	6.87	30%	189	0.05	$373
	2x2 U Tubes - U1	125	16.03	0%	59	0.02	$363
	T12 - 2 lamp 8FT.	83	19.33	30%	103	0.04	$355
	T8 lamp	113	7.60	30%	189	0.03	$347
	Offices - a2	58	16.03	0%	122	0.04	$346
	Child Development - A2	55	16.03	0%	122	0.04	$328
	2 - 2LP 1' x 4' fixtures Tandem 4 T8 28 watt UMX lamps LBF 120 Volt	156	5.71	30%	166	0.02	$317
	Roy Taylor - S1	1	10.00	0%	3,879	1.86	$284
	Truck Storage - M4	20	5.72	0%	701	0.08	$245
	Night lights	10	4.00	30%	2,003	0.23	$243
	Meeting a - S1	1	10.00	0%	3,233	1.55	$237
	Stairwell - G1	10	6.41	0%	199	0.13	$194
	2x2 u tubes - U1	66	16.03	0%	59	0.02	$192
	2x4 Basement - B1	32	16.03	0%	122	0.04	$191
	Office High ceiling - M1	8	16.03	0%	482	0.15	$188
	New Fixtures - b2	16	16.03	0%	219	0.07	$171
	T8-8'-2lamp	16	12.90	30%	317	0.08	$140
	Storage - B2	13	16.03	0%	219	0.07	$139

Program	Energy Efficiency Measure	Number of units	Measure life	LRAM Free Ridership	Annual energy savings (kWh/yr)	Annual demand savings (kW/yr)	Contribution to LRAM (2011$)
	Receiving - M2	4	10.00	0%	657	0.21	$128
	6 lamp T8 Warehouse	5	8.06	30%	1,438	0.23	$124
	Control Room - C1	30	5.72	0%	228	0.03	$119
	T8-4'-4lamp	14	12.90	30%	275	0.07	$106
	2 - 1' x 4' 2LP fixtures with 4 - T8 XP Lps CVG Tan LP 347 Volt	48	5.71	30%	166	0.02	$98
	2x2 U Tubes - U1	32	16.03	0%	59	0.02	$93
	Relamp with LED screw-in lamps	30	4.00	30%	245	0.03	$89
	u tube sensor - U1	30	48.08	0%	20	0.02	$87
	Office - s1	1	24.04	0%	1,189	0.57	$87
	Computer Room - U1	28	16.03	0%	59	0.02	$81
	2x2 utube hall - U1	27	16.03	0%	59	0.02	$78
	Womens - S1	1	10.00	0%	1,035	0.50	$76
	T12 - 2 lamp 4 FT.	35	19.33	30%	52	0.02	$75
	Meeting a - U1	25	48.08	0%	20	0.02	$73
	2' x 2' fixture with 2 - 4' T8 U6" Lps Volt LP	35	5.71	30%	166	0.02	$71
	2' x 4' fixture with 4 LP T8 28-watt UMX CVG lamps LP 347 volt	18	5.71	30%	307	0.04	$67
	Human Resources - U1	23	16.03	0%	59	0.02	$67
	Mens - S1	1	10.00	0%	905	0.43	$66
	Womens - S1	1	10.00	0%	905	0.43	$66
	Mens - S1	1	10.00	0%	905	0.43	$66
	1x4 Truck area - B1	11	16.03	0%	122	0.04	$66
	T8-4'-2lamp	17	12.90	30%	105	0.03	$49
	Womens - B1	8	32.05	0%	61	0.04	$48
	LEDs	15	5.32	30%	187	0.03	$46
	Cafeteria - U1	15	16.03	0%	59	0.02	$44

Program	Energy Efficiency Measure	Number of units	Measure life	LRAM Free Ridership	Annual energy savings (kWh/yr)	Annual demand savings (kW/yr)	Contribution to LRAM (2011$)
	Foreman - A1	5	16.03	0%	175	0.06	$43
	Mens - B1	7	32.05	0%	61	0.04	$42
	Womens - b1	7	32.05	0%	61	0.04	$42
	Mens - B1	7	32.05	0%	61	0.04	$42
	CFL 13W	16	1.52	30%	309	0.05	$36
	Offices - U1	12	16.03	0%	59	0.02	$35
	Hall - a2	5	8.01	0%	244	0.04	$30
	Office - a2	5	48.08	0%	41	0.04	$30
	Project - U1	9	16.03	0%	59	0.02	$26
	New Fixtures - b1	4	16.03	0%	122	0.04	$24
	Print Room - U1	8	16.03	0%	59	0.02	$23
	Hall - u1	8	16.03	0%	59	0.02	$23
	Health & Safety - U1	6	16.03	0%	59	0.02	$17
	F28T8	5	7.60	30%	204	0.03	$17
	CFL 13W	4	2.58	30%	182	0.05	$15
	CFL 20W	5	1.52	30%	362	0.06	$13
	CFL 7W	3	2.58	30%	205	0.05	$12
	Cal Struthers - U1	4	16.03	0%	59	0.02	$12
	2x2 utube hall - a1	1	5.72	0%	491	0.06	$9
	CFL 4W	2	2.58	30%	101	0.03	$4
	CFL 48W	1	2.58	30%	140	0.04	$3
	New fixtures - NF	2	16.03	0%	-350	-0.11	($34)
	on order - NF	6	12.02	0%	-467	-0.11	($103)
	T5 Complete - NF	18	11.45	0%	-491	-0.11	($308)
	New Fixtures - M3	14	16.03	0%	-688	-0.22	($471)
	on order - M3	16	12.02	0%	-918	-0.22	($538)

Program	Energy Efficiency Measure	Number of units	Measure life	LRAM Free Ridership	Annual energy savings (kWh/yr)	Annual demand savings (kW/yr)	Contribution to LRAM (2011$)
2008 Electricity Retrofit Incentive	Multiple	1	16.00	0%	3,918,703	768.07	$84,198
Total							**$152,872**

1. OPA 2010b and Trico 2007 are the sources of all LRAM inputs for the 2007 C/I Load Reduction program. OPA 2009 was used as the source of inputs for the 2008 ERIP.

2. Energy savings were calculated based on the energy efficient and base measure information provided by Trico 2007. The measure life in years for each measure in this program was derived from the annual operating hours of each measure (as provided by Trico 2007) and the ballast or bulb lifetime provided by OPA 2010b.

Table 14 – Residential program LRAM contributions and carrying charges.

Program	Year of savings	Savings (kWh)	Energy rate ($/kWh)	LRAM (programyear$)	Carrying charges ($)[1]	LRAM (2011$)
2005 Residential Holiday LED Lighting	2005	22,283	0.0157	$350	$66	$416
	2006	44,567	0.0158	$704	$94	$798
	2007	44,567	0.0159	$709	$61	$770
	2008	44,567	0.0157	$700	$28	$728
	2009	44,567	0.0157	$700	$7	$707
	2010	22,283	0.0154	$343	$1	$345
2005 Residential Holiday LED Lighting Total		*222,835*		*$3,506*	*$258*	***$3,764***
2005 Residential Mass Market Coupon Initiative	2005	139,644	0.0157	$2,195	$412	$2,607
	2006	279,289	0.0158	$4,413	$589	$5,002
	2007	279,289	0.0159	$4,441	$385	$4,826
	2008	279,289	0.0157	$4,385	$175	$4,560
	2009	279,289	0.0157	$4,385	$47	$4,432
	2010	273,816	0.0154	$4,217	$15	$4,231
2005 Residential Mass Market Coupon Initiative Total		*1,530,616*		*$24,035*	*$1,622*	***$25,657***
2005 Residential Real Time Monitoring Pilot	2005	16,044	0.0157	$252	$50	$302
	2006	16,044	0.0158	$253	$34	$287
	2007	16,044	0.0159	$255	$22	$277
	2008	16,044	0.0157	$252	$10	$262
	2009	16,044	0.0157	$252	$3	$255
	2010	16,044	0.0154	$247	$1	$248
2005 Residential Real Time Monitoring Pilot Total		*96,264*		*$1,512*	*$120*	***$1,631***
2006 CFL Distributed by HOB	2005	0	0.0157	$0	$0	$0
	2006	2,094,311	0.0158	$33,090	$4,155	$37,245
	2007	4,188,622	0.0159	$66,599	$5,777	$72,376
	2008	4,188,622	0.0157	$65,761	$2,620	$68,382

Program	Year of savings	Savings (kWh)	Energy rate ($/kWh)	LRAM (programyear$)	Carrying charges ($)[1]	LRAM (2011$)
	2009	4,188,622	0.0157	$65,761	$703	$66,464
	2010	4,188,622	0.0154	$64,505	$222	$64,727
2006 CFL Distributed by HOB Total		*18,848,801*		*$295,717*	*$13,476*	***$309,193***
2006 Cool Savings Rebate	2005	0	0.0157	$0	$0	$0
	2006	250,357	0.0158	$3,956	$528	$4,484
	2007	250,357	0.0159	$3,981	$345	$4,326
	2008	250,357	0.0157	$3,931	$157	$4,087
	2009	250,357	0.0157	$3,931	$42	$3,973
	2010	250,357	0.0154	$3,855	$13	$3,869
2006 Cool Savings Rebate Total		*1,251,784*		*$19,653*	*$1,086*	***$20,739***
2006 Fall EKC Program	2005	0	0.0157	$0	$0	$0
	2006	5,920,584	0.0158	$93,545	$12,496	$106,041
	2007	5,920,584	0.0159	$94,137	$8,165	$102,303
	2008	5,920,584	0.0157	$92,953	$3,704	$96,657
	2009	5,920,584	0.0157	$92,953	$993	$93,947
	2010	942,099	0.0154	$14,508	$50	$14,558
2006 Fall EKC Program Total		*24,624,434*		*$388,097*	*$25,408*	***$413,505***
2006 Holiday Light Exchange	2005	0	0.0157	$0	$0	$0
	2006	0	0.0158	$0	$0	$0
	2007	0	0.0159	$0	$0	$0
	2008	0	0.0157	$0	$0	$0
	2009	0	0.0157	$0	$0	$0
	2010	0	0.0154	$0	$0	$0
2006 Holiday Light Exchange Total		*0*		*$0*	*$0*	***$0***
2006 Spring EKC Program	2005	0	0.0157	$0	$0	$0
	2006	3,649,493	0.0158	$57,662	$7,703	$65,365

Program	Year of savings	Savings (kWh)	Energy rate ($/kWh)	LRAM (programyear$)	Carrying charges ($)[1]	LRAM (2011$)
	2007	3,649,493	0.0159	$58,027	$5,033	$63,060
	2008	3,649,493	0.0157	$57,297	$2,283	$59,580
	2009	3,649,493	0.0157	$57,297	$612	$57,909
	2010	291,787	0.0154	$4,494	$15	$4,509
2006 Spring EKC Program Total		*14,889,761*		*$234,777*	*$15,646*	***$250,423***
2007 CFL Distributed by HOB	2005	0	0.0157	$0	$0	$0
	2006	0	0.0158	$0	$0	$0
	2007	757,250	0.0159	$12,040	$958	$12,998
	2008	1,514,499	0.0157	$23,778	$947	$24,725
	2009	1,514,499	0.0157	$23,778	$254	$24,032
	2010	1,514,499	0.0154	$23,323	$80	$23,403
2007 CFL Distributed by HOB Total		*5,300,747*		*$82,919*	*$2,240*	***$85,159***
2007 Cool Savings Rebate	2005	0	0.0157	$0	$0	$0
	2006	0	0.0158	$0	$0	$0
	2007	838,601	0.0159	$13,334	$1,157	$14,490
	2008	838,601	0.0157	$13,166	$525	$13,691
	2009	838,601	0.0157	$13,166	$141	$13,307
	2010	838,601	0.0154	$12,914	$44	$12,959
2007 Cool Savings Rebate Total		*3,354,405*		*$52,580*	*$1,866*	***$54,447***
2007 EKC Program	2005	0	0.0157	$0	$0	$0
	2006	0	0.0158	$0	$0	$0
	2007	3,667,704	0.0159	$58,316	$5,058	$63,375
	2008	3,623,225	0.0157	$56,885	$2,266	$59,151
	2009	3,623,225	0.0157	$56,885	$608	$57,493
	2010	3,623,225	0.0154	$55,798	$192	$55,989
2007 EKC Program Total		*14,537,379*		*$227,883*	*$8,124*	***$236,008***

Program	Year of savings	Savings (kWh)	Energy rate ($/kWh)	LRAM (programyear$)	Carrying charges ($)[1]	LRAM (2011$)
2007 Great Refrigerator Roundup	2005	0	0.0157	$0	$0	$0
	2006	0	0.0158	$0	$0	$0
	2007	238,145	0.0159	$3,787	$328	$4,115
	2008	238,145	0.0157	$3,739	$149	$3,888
	2009	238,145	0.0157	$3,739	$40	$3,779
	2010	238,145	0.0154	$3,667	$13	$3,680
2007 Great Refrigerator Roundup Total		*952,580*		*$14,932*	*$530*	***$15,462***
2007 Summer Savings	2005	0	0.0157	$0	$0	$0
	2006	0	0.0158	$0	$0	$0
	2007	4,505,641	0.0159	$71,640	$6,214	$77,854
	2008	4,505,641	0.0157	$70,739	$2,818	$73,557
	2009	0	0.0157	$0	$0	$0
	2010	0	0.0154	$0	$0	$0
2007 Summer Savings Total		*9,011,283*		*$142,378*	*$9,032*	***$151,411***
2008 Cool Savings Rebate	2005	0	0.0157	$0	$0	$0
	2006	0	0.0158	$0	$0	$0
	2007	0	0.0159	$0	$0	$0
	2008	604,049	0.0157	$9,484	$378	$9,861
	2009	604,049	0.0157	$9,484	$101	$9,585
	2010	604,049	0.0154	$9,302	$32	$9,334
2008 Cool Savings Rebate Total		*1,812,146*		*$28,269*	*$511*	***$28,781***
2008 EKC Program	2005	0	0.0157	$0	$0	$0
	2006	0	0.0158	$0	$0	$0
	2007	0	0.0159	$0	$0	$0
	2008	3,323,091	0.0157	$52,173	$2,079	$54,251
	2009	3,308,635	0.0157	$51,946	$555	$52,501
	2010	3,308,635	0.0154	$50,953	$175	$51,128

Program	Year of savings	Savings (kWh)	Energy rate ($/kWh)	LRAM (programyear$)	Carrying charges ($)[1]	LRAM (2011$)
2008 EKC Program Total		*9,940,360*		*$155,071*	*$2,809*	***$157,880***
2008 Great Refrigerator Roundup	2005	0	0.0157	$0	$0	$0
	2006	0	0.0158	$0	$0	$0
	2007	0	0.0159	$0	$0	$0
	2008	531,075	0.0157	$8,338	$332	$8,670
	2009	531,075	0.0157	$8,338	$89	$8,427
	2010	531,075	0.0154	$8,179	$28	$8,207
2008 Great Refrigerator Roundup Total		*1,593,225*		*$24,854*	*$449*	***$25,304***
2008 peaksaver®	2005	0	0.0157	$0	$0	$0
	2006	0	0.0158	$0	$0	$0
	2007	0	0.0159	$0	$0	$0
	2008	18,477	0.0157	$290	$12	$302
	2009	18,477	0.0157	$290	$3	$293
	2010	18,477	0.0154	$285	$1	$286
2008 peaksaver® Total		*55,430*		*$865*	*$16*	***$880***
2008 Summer Sweepstakes	2005	0	0.0157	$0	$0	$0
	2006	0	0.0158	$0	$0	$0
	2007	0	0.0159	$0	$0	$0
	2008	128,824	0.0157	$2,023	$81	$2,103
	2009	0	0.0157	$0	$0	$0
	2010	0	0.0154	$0	$0	$0
2008 Summer Sweepstakes Total		*128,824*		*$2,023*	*$81*	***$2,103***
Residential Total		*108,150,873*		*$1,699,070*	*$83,275*	***$1,782,345***

1. Carrying charges are calculated quarterly, at the measure (not program) level to capture different carrying charge interest rates by quarter, program ramp up, and measure life.

Table 15 – GS < 50 kW program LRAM contributions and carrying charges.

Program	Year of savings	Savings (kWh)	Energy rate ($/kWh)	LRAM (programyear$)	Carrying charges ($)[1]	LRAM (2011$)
2008 High Performance New Construction	2005	0	0.0182	$0	$0	$0
	2006	0	0.0182	$0	$0	$0
	2007	0	0.0183	$0	$0	$0
	2008	9,727	0.0181	$176	$7	$183
	2009	9,727	0.0181	$176	$2	$178
	2010	9,727	0.0178	$173	$1	$174
2008 High Performance New Construction Total		*29,181*		*$525*	*$9*	***$535***
2008 Renewable Energy Standard Offer	2005	0	0.0182	$0	$0	$0
	2006	0	0.0182	$0	$0	$0
	2007	0	0.0183	$0	$0	$0
	2008	25,595	0.0181	$463	$18	$482
	2009	25,595	0.0181	$463	$5	$468
	2010	25,595	0.0178	$456	$2	$457
2008 Renewable Energy Standard Offer Total		*76,784*		*$1,382*	*$25*	***$1,407***
GS < 50 kW Total		*105,964*		*$1,907*	*$34*	***$1,942***

1. Carrying charges are calculated quarterly, at the measure (not program) level to capture different carrying charge interest rates by quarter, program ramp up, and measure life.

Table 16 – GS 50 to 699 kW program LRAM contributions and carrying charges.

Program	Year of savings	Savings (kW)	Energy rate ($/kW/yr)	LRAM (programyear$)	Carrying charges ($)[1]	LRAM (2011$)
2007 C/I Load Control Program	2007	37	28.3116	$1,060	$84	$1,145
	2008	75	27.9996	$2,097	$84	$2,180
	2009	75	28.0248	$2,096	$22	$2,118
	2010	75	27.5220	$2,057	$7	$2,064
2007 C/I Load Control Program Total				*$7,310*	*$197*	***$7,507***
2008 Electricity Retrofit Incentive	2008	415	27.9996	$11,626	$463	$12,089
	2009	415	28.0248	$11,636	$124	$11,761
	2010	415	27.5220	$11,428	$39	$11,467
2008 Electricity Retrofit Incentive Total				*$34,690*	*$627*	***$35,317***
GS 50 to 699 kW Total				*$42,000*	*$824*	***$42,824***

1. Carrying charges are calculated quarterly, at the measure (not program) level to capture different carrying charge interest rates by quarter, program ramp up, and measure life.

Table 17 – GS 700 to 4999 kW program LRAM contributions and carrying charges.

Program	Year of savings	Savings (kW)	Energy rate ($/kW/yr)	LRAM (programyear$)	Carrying charges ($)[1]	LRAM (2011$)
2007 C/I Load Control Program	2007	187	46.1112	$8,639	$687	$9,326
	2008	375	45.6036	$17,084	$681	$17,765
	2009	374	45.6444	$17,078	$183	$17,260
	2010	374	44.8260	$16,757	$58	$16,815
2007 C/I Load Control Program Total				*$59,558*	*$1,608*	***$61,167***
2008 Electricity Retrofit Incentive	2008	353	45.6036	$16,091	$641	$16,732
	2009	353	45.6444	$16,106	$172	$16,278
	2010	353	44.8260	$15,817	$54	$15,871
2008 Electricity Retrofit Incentive Total				*$48,014*	*$868*	***$48,881***
GS 700 to 4999 kW Total				*$107,572*	*$2,476*	***$110,048***

1. Carrying charges are calculated quarterly, at the measure (not program) level to capture different carrying charge interest rates by quarter, program ramp up, and measure life.

The LRAM without carrying charges (the sum of the grand totals from Table 14 to Table 17) is $1,850,549. The carrying charges are $86,610.

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Hydro One Brampton Networks Inc.

Calculations in response to VECC IR69b(ii)

Prepared by IndEco Strategic Consulting Inc.
17 September 2010

CFLs distributed by HOBNI

Technology input assumptions

Equipment life (years)	4	
Equipment cost	$2	
Annual energy savings	104.4	

Load type	Lighting	Energy savings (kWh)
Winter peak	15%	15.66
Winter mid	7%	7.308
Winter off-peak	19%	19.836
Summer peak	0%	0
Summer mid	11%	11.484
Summer off-peak	13%	13.572
Shoulder mid	17%	17.748
Shoulder off	17%	17.748
Total	99%	103.356

Discount factor	7.87%
Distribution loss factor	0%

Program

Units distributed	48784
Free riders	10%

Output

Unit technology benefit	$25.96	See attached table
Less total technology cost	$2	
Unit technology net benefits	$23.96	

Gross benefits (units x unit benefits and costs)

Total technology benefit	$1,266,432.64
Total technology cost	$97,568.00
Technology net benefits	$1,168,864.64

Net benefits (gross benefits x (1 - free rider rate))

Total technology benefit	$1,139,789.38
Total technology cost	$87,811.20
Technology net benefits	$1,051,978.18

SSM incentive rate	5%

SSM claim (technology net benefits x SSM incentive rate)	$52,598.91

CFLs distributed by Hydro One Brampton -- calculation of unit TRC benefits

Table A: measure savings

			Measure electricity savings (kWh)						
year	Energy Savings Winter Peak (kW.h)	Energy Savings Winter Mid (kW.h)	Energy Savings Winter Off Peak (kW.h)	Energy Savings Summer Peak (kW.h)	Energy Savings Summer Mid (kW.h)	Energy Savings Summer Off Peak (kW.h)	Energy Savings Shoulder Mid (kW.h)	Energy Savings Shoulder Off (kW.h)	Total (kWh)
1	15.66	7.308	19.836	0	11.484	13.572	17.748	17.748	103.356
2	15.66	7.308	19.836	0	11.484	13.572	17.748	17.748	103.356
3	15.66	7.308	19.836	0	11.484	13.572	17.748	17.748	103.356
4	15.66	7.308	19.836	0	11.484	13.572	17.748	17.748	103.356

Table B: measure savings including distribution losses (not accounted for)

			Measure energy savings (kWh)						
year	Energy Savings Winter Peak (kW.h)	Energy Savings Winter Mid (kW.h)	Energy Savings Winter Off Peak (kW.h)	Energy Savings Summer Peak (kW.h)	Energy Savings Summer Mid (kW.h)	Energy Savings Summer Off Peak (kW.h)	Energy Savings Shoulder Mid (kW.h)	Energy Savings Shoulder Off (kW.h)	Total (kWh)
1	15.66	7.308	19.836	0	11.484	13.572	17.748	17.748	103.356
2	15.66	7.308	19.836	0	11.484	13.572	17.748	17.748	103.356
3	15.66	7.308	19.836	0	11.484	13.572	17.748	17.748	103.356
4	15.66	7.308	19.836	0	11.484	13.572	17.748	17.748	103.356

Table C: Avoided costs

		Ontario seasonal average avoided energy cost (CAD$/MWh)						
year	Energy Savings Winter Peak	Energy Savings Winter Mid	Energy Savings Winter Off Peak	Energy Savings Summer Peak	Energy Savings Summer Mid	Energy Savings Summer Off Peak	Energy Savings Shoulder Mid	Energy Savings Shoulder Off
2007	$124.6	$84.3	$45.2	$111.5	$79.6	$45.9	$81.4	$40.8
2008	$115.4	$86.8	$48.9	$110.6	$83.6	$50.1	$90.4	$44.9
2009	$111.9	$77.1	$48.9	$104.5	$79.5	$47.6	$85.8	$43.4
2010	$113.5	$77.4	$52.1	$107.0	$80.5	$48.2	$83.5	$43.4

Table D: Avoided cost savings *(Table B x Table C)*

		Savings ($)						
year	Energy Savings Winter Peak	Energy Savings Winter Mid	Energy Savings Winter Off Peak	Energy Savings Summer Peak	Energy Savings Summer Mid	Energy Savings Summer Off Peak	Energy Savings Shoulder Mid	Energy Savings Shoulder Off
1	$1.95	$0.62	$0.90	$0.00	$0.91	$0.62	$1.44	$0.72
2	$1.81	$0.63	$0.97	$0.00	$0.96	$0.68	$1.60	$0.80
3	$1.75	$0.56	$0.97	$0.00	$0.91	$0.65	$1.52	$0.77
4	$1.78	$0.57	$1.03	$0.00	$0.92	$0.65	$1.48	$0.77

Table E: discounted avoided electricity cost savings *(Table D x Discount rate factor)*

			Nominal savings ($)							
year	Discount rate factor	Energy Savings Winter Peak	Energy Savings Winter Mid	Energy Savings Winter Off Peak	Energy Savings Summer Peak	Energy Savings Summer Mid	Energy Savings Summer Off Peak	Energy Savings Shoulder Mid	Energy Savings Shoulder Off	Total
1	1.00	$1.95	$0.62	$0.90	$0.00	$0.91	$0.62	$1.44	$0.72	$7.17
2	1.08	$1.68	$0.59	$0.90	$0.00	$0.89	$0.63	$1.49	$0.80	$6.91
3	1.16	$1.51	$0.48	$0.83	$0.00	$0.78	$0.56	$1.31	$0.77	$6.13
4	1.26	$1.42	$0.45	$0.82	$0.00	$0.74	$0.52	$1.18	$0.77	$5.74
Total										$25.96

CFLs distributed by EKC

Technology input assumptions

Equipment life (years)	8	
Equipment cost	$2	
Annual energy savings	43	

Load type	Lighting	Energy savings (kWh)
Winter peak	15%	6.45
Winter mid	7%	3.01
Winter off-peak	19%	8.17
Summer peak	0%	0
Summer mid	11%	4.73
Summer off-peak	13%	5.59
Shoulder mid	17%	7.31
Shoulder off	17%	7.31
Total	99%	42.57

Discount factor	7.87%
Distribution loss factor	0%

Program

Units distributed	65999
Free riders	10%

Output

Unit technology benefit	$19.75	See attached table
Less total technology cost	$2	
Unit technology net benefits	$17.75	

Gross benefits (units x unit benefits and costs)

Total technology benefit	$1,303,409.20
Total technology cost	$131,998.00
Technology net benefits	$1,171,411.20

Net benefits (gross benefits x (1 - free rider rate))

Total technology benefit	$1,173,068.28
Total technology cost	$118,798.20
Technology net benefits	$1,054,270.08

SSM incentive rate	5%
SSM claim (technology net benefits x SSM incentive rate)	$52,713.50

CFLs distributed under the EKC

Table A: measure savings

		Measure electricity savings (kWh)							
year	Energy Savings Winter Peak (kWh)	Energy Savings Winter Mid (kWh)	Energy Savings Winter Off Peak (kWh)	Energy Savings Summer Peak (kWh)	Energy Savings Summer Mid (kWh)	Energy Savings Summer Off Peak (kWh)	Energy Savings Shoulder Mid (kWh)	Energy Savings Shoulder Off (kWh)	measure demand savings (onpeak kW)
1	6.449954	3.0099786	8.1699418	0	4.7299663	5.5899602	7.3099479	7.3099479	0.0013
2	6.449954	3.0099786	8.1699418	0	4.7299663	5.5899602	7.3099479	7.3099479	0.0013
3	6.449954	3.0099786	8.1699418	0	4.7299663	5.5899602	7.3099479	7.3099479	0.0013
4	6.449954	3.0099786	8.1699418	0	4.7299663	5.5899602	7.3099479	7.3099479	0.0013
5	6.449954	3.0099786	8.1699418	0	4.7299663	5.5899602	7.3099479	7.3099479	0.0013
6	6.449954	3.0099786	8.1699418	0	4.7299663	5.5899602	7.3099479	7.3099479	0.0013
7	6.449954	3.0099786	8.1699418	0	4.7299663	5.5899602	7.3099479	7.3099479	0.0013
8	6.449954	3.0099786	8.1699418	0	4.7299663	5.5899602	7.3099479	7.3099479	0.0013

Table B: measure savings including distrubtion losses

		Measure energy savings (kWh)							
year	Energy Savings Winter Peak (kWh)	Energy Savings Winter Mid (kWh)	Energy Savings Winter Off Peak (kWh)	Energy Savings Summer Peak (kWh)	Energy Savings Summer Mid (kWh)	Energy Savings Summer Off Peak (kWh)	Energy Savings Shoulder Mid (kWh)	Energy Savings Shoulder Off (kWh)	measure demand savings (onpeak kW)
1	6.449954	3.0099786	8.1699418	0	4.7299663	5.5899602	7.3099479	7.3099479	0.001
2	6.449954	3.0099786	8.1699418	0	4.7299663	5.5899602	7.3099479	7.3099479	0.001
3	6.449954	3.0099786	8.1699418	0	4.7299663	5.5899602	7.3099479	7.3099479	0.001
4	6.449954	3.0099786	8.1699418	0	4.7299663	5.5899602	7.3099479	7.3099479	0.001
5	6.449954	3.0099786	8.1699418	0	4.7299663	5.5899602	7.3099479	7.3099479	0.001
6	6.449954	3.0099786	8.1699418	0	4.7299663	5.5899602	7.3099479	7.3099479	0.001
7	6.449954	3.0099786	8.1699418	0	4.7299663	5.5899602	7.3099479	7.3099479	0.001
8	6.449954	3.0099786	8.1699418	0	4.7299663	5.5899602	7.3099479	7.3099479	0.001

Table C: Avoided costs

		Ontario seasonal average avoided energy cost (CAD$/MWh)							Avoided capacity		
year	Energy Savings Winter Peak	Energy Savings Winter Mid	Energy Savings Winter Off Peak	Energy Savings Summer Peak	Energy Savings Summer Mid	Energy Savings Summer Off Peak	Energy Savings Shoulder Mid	Energy Savings Shoulder Off	Generation ($/kW-yr)	Transmission ($/kW-yr)	Distribution ($/kW-yr)
2007	$124.6	$84.3	$45.2	$111.5	$79.6	$45.9	$81.4	$40.8	$0.00	$0.00	$0.00
2008	$115.4	$86.8	$48.9	$110.6	$83.6	$50.1	$90.4	$44.9	$74.65	$5.62	$0.00
2009	$111.9	$77.1	$48.9	$104.5	$79.5	$47.6	$85.8	$43.4	$83.57	$5.76	$7.17
2010	$113.5	$77.4	$52.1	$107.0	$80.5	$48.2	$83.5	$43.4	$71.49	$5.90	$7.35
2011	$110.2	$77.3	$52.7	$103.2	$81.3	$48.5	$84.2	$43.0	$85.42	$6.05	$7.54
2012	$112.4	$78.9	$53.3	$113.1	$84.6	$51.2	$88.5	$47.8	$81.20	$6.20	$7.73
2013	$125.2	$86.4	$59.9	$116.9	$91.3	$54.0	$92.5	$51.9	$61.60	$6.36	$7.92
2014	$125.7	$92.4	$62.8	$127.9	$96.8	$56.7	$98.9	$54.4	$46.63	$6.52	$8.12

Table D: Avoided cost savings

		Savings ($)							Savings		
year	Energy Savings Winter Peak	Energy Savings Winter Mid	Energy Savings Winter Off Peak	Energy Savings Summer Peak	Energy Savings Summer Mid	Energy Savings Summer Off Peak	Energy Savings Shoulder Mid	Energy Savings Shoulder Off	Generation	Transmission	Distribution
1	$0.80	$0.25	$0.37	$0.00	$0.38	$0.26	$0.60	$0.30	$0.00	$0.00	$0.00
2	$0.74	$0.26	$0.40	$0.00	$0.40	$0.28	$0.66	$0.33	$0.10	$0.01	$0.00
3	$0.72	$0.23	$0.40	$0.00	$0.38	$0.27	$0.63	$0.32	$0.11	$0.01	$0.01
4	$0.73	$0.23	$0.43	$0.00	$0.38	$0.27	$0.61	$0.32	$0.09	$0.01	$0.01
5	$0.71	$0.23	$0.43	$0.00	$0.38	$0.27	$0.62	$0.31	$0.11	$0.01	$0.01
6	$0.72	$0.24	$0.44	$0.00	$0.40	$0.29	$0.65	$0.35	$0.11	$0.01	$0.01
7	$0.81	$0.26	$0.49	$0.00	$0.43	$0.30	$0.68	$0.38	$0.08	$0.01	$0.01
8	$0.81	$0.28	$0.51	$0.00	$0.46	$0.32	$0.72	$0.40	$0.06	$0.01	$0.01

Table E: discounted avoided electricity cost savings

			Nominal savings ($)							Nominal savings			
year	Discount rate factor	Energy Savings Winter Peak	Energy Savings Winter Mid	Energy Savings Winter Off Peak	Energy Savings Summer Peak	Energy Savings Summer Mid	Energy Savings Summer Off Peak	Energy Savings Shoulder Mid	Energy Savings Shoulder Off	Generation	Transmission	Distribution	**Total**
1	1.00	$0.80	$0.25	$0.37	$0.00	$0.38	$0.26	$0.60	$0.30	$0.00	$0.00	$0.00	$2.95
2	1.08	$0.69	$0.24	$0.37	$0.00	$0.37	$0.26	$0.61	$0.30	$0.09	$0.01	$0.00	$2.94
3	1.16	$0.62	$0.20	$0.34	$0.00	$0.32	$0.23	$0.54	$0.27	$0.09	$0.01	$0.01	$2.63
4	1.26	$0.58	$0.19	$0.34	$0.00	$0.30	$0.21	$0.49	$0.25	$0.07	$0.01	$0.01	$2.45
5	1.35	$0.52	$0.17	$0.32	$0.00	$0.28	$0.20	$0.45	$0.23	$0.08	$0.01	$0.01	$2.28
6	1.46	$0.50	$0.16	$0.30	$0.00	$0.27	$0.20	$0.44	$0.24	$0.07	$0.01	$0.01	$2.19
7	1.58	$0.51	$0.17	$0.31	$0.00	$0.27	$0.19	$0.43	$0.24	$0.05	$0.01	$0.01	$2.19
8	1.70	$0.48	$0.16	$0.30	$0.00	$0.27	$0.19	$0.43	$0.23	$0.04	$0.00	$0.01	$2.10
Total		$4.71	$1.54	$2.65	$0.00	$2.47	$1.73	$3.99	$2.07	$0.50	$0.04	$0.04	$19.75

APPENDIX AG

A copy of this Appendix is filed in confidence with the Ontario Energy Board and will be made available to interveners that sign a declaration and undertaking form in accordance with the OEB Practice Direction on Confidential Filing.

APPENDIX AH

Hydro One Brampton Inc.
Submission to the Board of Directors

Date: June 17, 2004

Subject: Revision to Dividend Policy

Recommended and Approved for Submission to the Board by:

Information Copy
Original Signed By

Roger Albert
President & CEO

Issue:
At the October 24, 2001 Board meeting, a dividend policy was approved which requires that Management submit dividend recommendations to the Board quarterly. At the Board meeting on April 7, 2004, the Board requested that Management review the policy and consider changes to allow for the declaration of dividends to occur in the fourth quarter only.

Relevant Factors:
In view of the growth rate in Brampton, the need for capital to expand facilities to support growth is very high. As a result of this cash requirement, it is difficult to assess whether and in what amount dividends should be paid until later in the year. To this end, the attached policy has been revised to replace the first point from "Management will quarterly submit to the Board dividend recommendations..." to "Management will submit to the Board in the fourth quarter dividend recommendations...", together with other non-substantive revisions.

Recommendation:
That Hydro One Brampton Inc. and its subsidiary, Hydro One Brampton Networks Inc., adopt and approve the dividend policy revised and restated in Schedule A as attached hereto.

SCHEDULE "A"

HYDRO ONE BRAMPTON INC
HYDRO ONE BRAMPTON NETWORKS INC.

Dividend Policy

1. Management will submit to the Board of Directors of Hydro One Brampton Inc. in the fourth quarter, a dividend recommendation for the declaration and payment of dividends on its common shares based on the following considerations:

    - Results of operations;
    - Financial condition;
    - Cash requirements; and,
    - Maintenance of an appropriate capital structure.

2. Management will certify to such Board that declaring and paying the recommended dividend will not compromise the Corporation's financial solvency.

3. The Board will, at its sole discretion, declare any dividends based on consideration of Management's recommendation and certification, and other pertinent factors.

APPENDIX AI

Attachment 1

STANDARD & POOR'S

CORPORATE RATINGS

Hydro One Inc.

Corporate Credit Rating

A+/Stable/A-1

Primary Credit Analyst:
Nicole Martin
Toronto
(1) 416-507-2560
nicole_martin@
standardandpoors.com

RatingsDirect Publication Date
July 21, 2008

Major Rating Factors

Strengths:

- Low-risk electricity transmission and distribution network businesses
- Monopoly position
- Regulated cash flows
- Supportive shareholder

Weaknesses:

- Intermediate financial risk profile
- Large capital expenditure program

Rationale

The ratings on Hydro One Inc., a large, regulated transmission and local electricity distribution company (LDC) in the Province of Ontario (AA/Positive/A-1+), reflect the company's low-risk monopoly electricity transmission and distribution networks, secure and relatively predictable regulated cash flows, and the support of its owner, the province. Offsetting its excellent business risk profile is an intermediate financial risk profile that will face challenges from a large capital expenditure program in the next several years. The company had C$5.6 billion in debt outstanding as of Dec. 31, 2007.

Hydro One's monopoly position, the business' asset-intensive nature, and regulatory oversight limit competitive risk. It owns and operates more than 96% of the province's transmission network as measured by revenue, and its distribution network service territory covers about 75% of the province. Both the electricity transmission and distribution business carry relatively low operating risk, and exhibit average operational efficiency and reliability. We view the transmission operations as lower risk than distribution.

The Ontario Energy Board's (OEB) regulatory framework supports Hydro One's cash flow stability. The framework allows for the recovery of prudent transmission and distribution costs and the opportunity to earn a modest return. Regulatory cost recovery is generally predictable and timeliness is improving. Furthermore, in the current environment, the LDC's exposure to commodity risk is limited and the transmission provider has none. Although the LDC must bill electricity customers for the commodity delivered, the cost is a flow-through. The company has no obligation to ensure an adequate supply of electricity and is not burdened with the procurement process or power purchase agreements. Net distribution and transmission revenues are subject to modest volumetric risk due to weather. There is no near-term expectation of energy policy or electricity market framework initiatives that would affect the regulatory environment or the company's credit quality.

Hydro One has an intermediate financial risk profile that could weaken in the next few years. Adjusted funds from operation (AFFO)-to-total debt should remain about 12% compared with its 2007 level of 14%. Sustainable AFFO interest coverage of 3.7x as of Dec. 31, 2007 could fall below 3x in 2008. The extent of the decline in the utility's cash flow strength will depend largely on regulatory approvals and execution of planned capital expenditures, the impact of weather on revenue net of commodity costs, and the company's ability to find operating efficiencies sufficient to offset the OEB's performance-based pressures on rates.

During the upcoming period of higher-than-average construction, Hydro One's leverage, as measured by adjusted total debt-to-total capital, is likely to creep back up to the historical level of about 64%, compared with 58% in 2007. Although predominantly funded from internal sources (about 80%), capital spending during the next few years will be a drain on the company's cash flow, reducing financial flexibility and pressuring cash flow coverage. The utility has budgeted C$1.4 billion in capital expenditure for 2008, higher than the C$1 billion spent in 2007 and a historical average of about C$700 million in the 2002-2006 period. The transmission system requires upgrades and expansion to accommodate new and retiring generation, increased imports and exports, and modest growth in domestic demand. The 2008 capital program also includes part of the estimated remaining C$670 million investment that Hydro One will make in smart meters for all distribution customers under a provincial directive by 2010.

The province's ownership of Hydro One enhances the utility's credit quality. Although Ontario does not formally guarantee the company's debt obligations, Hydro One's strategic nature within the provincial economy and the government's demonstrated willingness to assist the business (with liquidity support) under extraordinary circumstances in the past bode well for similar future support.

Short-term credit factors

The short-term rating on Hydro One is 'A-1'. Unused and committed bank lines, together with strong cash flow from operations and access to debt capital markets, provide Hydro One with sufficient liquidity and the financial flexibility to meet the company's estimated capital expenditure of C$1.4 billion, annual dividend payments of C$250 million-C$290 million, and C$540 million of debt maturing in 2008. Furthermore, the company remains well within its banking covenant of total debt-to-total capital of 75% and has no material adverse change clauses that could trigger a default.

To support liquidity, the company can draw on:

- A committed C$1 billion bank line (maturing August 2010) that remained largely available as of March 31. The bank line is used for general corporate purposes and to support Hydro One's

C$1 billion Canadian commercial paper (CP) program. The line was increased to C$1 billion from C$750 million as of Jan. 28, 2008.

- Annual regulated cash flows, as represented by unadjusted FFO, estimated at about C$900 million in 2008;
- A medium-term note shelf program, maturing in July 2009, that had C$1.65 billion remaining capacity as of March 31; and
- Discretionary capital expenditure estimated at more than C$200 million in 2008.

Outlook

The stable outlook reflects Hydro One's excellent business risk profile, which mitigates financial pressures of a larger-than-normal capital spending program. An adverse regulatory ruling or market restructuring (such as the assumption of the obligation to supply) could lead to a negative rating action. An upgrade is unlikely without the assurance of a much stronger balance sheet, and deeper cash flow-interest and -debt coverage. A significant change in the relationship with the government shareholder could move the rating up or down, but likely not more than a notch given the company's underlying credit strength.

Business Description

Low-risk, regulated, wires operations dominate business risk profile

Low-risk, regulated transmission assets represent about 57% of the total business, low risk, regulated distribution assets 42%, and unregulated telecom assets about 1%. The marketing of surplus fiber optic capacity through subsidiary Hydro One Telecom is not material to the credit analysis, given the operation's small size. It contributes about 1% of funds from operations (FFO).

Hydro One owns and operates a 28,915-kilometer (km) high-voltage Ontario-wide transmission system. It is the second-largest transmitter in Canada and can accommodate exports of about 5,800 megawatts (MW) and imports of 4,000 MW to and from interconnected Canadian provinces and the U.S. The transmission system had a 20-minute system peak of 25,809 MW and transmitted an average of 153 terawatt-hours in the last three years.

The company also delivers electricity to about 1.3 million customers through its 122,933-km distribution system, one of the country's largest LDCs. The system has a low customer density, covering approximately 75% of Ontario and distributed about 20% of electricity consumed in the province. Hydro One also owns Hydro One Brampton, a regulated LDC serving the City of Brampton (AAA/Stable/—; 126,000 customers).

Government ownership enhances rating

Government support enhances Hydro One's standalone credit quality by one notch. The company's close relationship with its owner has been demonstrated through the provision of temporary financial support in past extraordinary circumstances. We expect that a similar level of support would be forthcoming in the future under similar circumstances. The province offered temporary access to government treasury resources when unforeseen changes in provincial policy exposed the company's distribution operations to liquidity pressures. At the end of fiscal 2007, the province had cash and temporary investments of close to C$7 billion, which provided adequate immediate liquidity that the province's superior access to capital markets supports.

We consider Hydro One to be a commercial enterprise. Nevertheless, the company is wholly owned by the Province of Ontario, which holds all the common and preferred shares outstanding. The province appoints Hydro One's board of directors, and although the board sets the company's business plan and dividend policy, the government reviews them before implementation. Management updates government staff on Hydro One's monthly financial and operational performance. We do not expect a change in ownership.

The potential for extraordinary assistance in a stress scenario is factored into the standalone creditworthiness of this essential institution. A change in Hydro One's standalone creditworthiness or a change in the ratings on the province could affect our rating methodology and outcome.

Business Risk Profile

A stable regulatory regime supports credit quality

The OEB provides regulatory oversight of Hydro One's monopoly transmission and distribution operations. The regulatory framework supports predictable cash flow. Unexpected-but-prudent costs incurred are generally recovered through tariffs, but subject to regulatory lag. Allowed returns are relatively low and constrain the upside in cash flows.

The OEB sets rates by estimating Hydro One's revenue requirement, given forecast consumption. The company must submit separate transmission and distribution applications to the regulator. Revenue requirements are determined on a forward test year and acknowledge the company's capital plans and operating costs. The regulator assumes a deemed capital structure of 60% debt and 40% equity, and includes the cost of debt and a return on equity in the requirement. The allowed economic return is based on a formula linked to long-term Government of Canada bonds plus an equity risk premium.

The OEB approved Hydro One's 2007 and 2008 transmission revenue requirement in August 2007. The regulatory decision allowed for both capital and operating expenditures for 2007 and 2008 as per the company's application and for a return on equity of 8.35%, consistent with the methodology used for all electricity distribution utilities in Ontario. The company had requested a higher return. Previously, the regulated transmission tariff had been based on 60% debt, 4% preferred shares and 36% common equity and a higher allowed return (9.88%). The company is likely to submit its application for 2009 and 2010 transmission rates in third-quarter 2008.

At the time of publication, Hydro One was seeking approval of a distribution revenue requirement of C$1.07 billion for 2008. In addition to operating costs, the revenue requirement will allow for a 60% debt/40% equity capital structure and a formula-driven allowed return (8.35% in 2008), as for all OEB-regulated LDCs in Ontario. The rate year begins May 1 for both the transmission and distribution sectors.

There is a long history of regulated entities in both Ontario and Canada being allowed to recoup unforeseen costs (regulatory assets) or having to refund the customer (regulatory liabilities) after the fact through rates. The cash recovery or repayment is subject to a prudency review and regulatory approval. Depending on the magnitude, the OEB may spread the recovery over multiple years to avoid rate shock. For Hydro One, the net recovery of regulatory assets is not material in 2008.

Removing the current commodity pass-through mechanisms or assigning an obligation to ensure adequate supply of electricity for Hydro One's end-use customers, would negatively influence the ratings. Hydro One's LDC bills its customers for the entire cost of electricity delivered including related transmission, system operation, distribution, and commodity costs. The LDC's financial health is protected from exposure to commodity price volatility by timely mechanisms that allow cost pass through to customers.

Ontario is Hydro One's primary market

Hydro One's monopoly operations serve the Province of Ontario. The company's transmission operations serve the entire province; its distribution business, apart from its Brampton network on the outskirts of Toronto (AA/Stable/A-1+; the provincial capital), is largely rural based.

The province has a well diversified economy with a positive but moderate outlook for 2008. Real GDP should increase by 1.1% from 2007 as employment growth slows to 1.0% and the unemployment rate rises modestly to 6.6%. The province's well-diversified economy generated another robust performance in 2007 as real GDP rose 2.1% in 2007 from 2006. Furthermore, employment increased 1.6% in 2007 from a year earlier, as the unemployment rate remained virtually unchanged at 6.4% (6.3% in 2006). Despite the high Canadian dollar and weak international exports, interprovincial exports have continued to grow, offsetting weakness in international exports. (For more information on the Province of Ontario, please refer to our most recent analysis, published May 29, 2008, on RatingsDirect.)

The company's distribution customer base enjoys slow-but-steady growth; the number of customers has increased by 1.2%-1.6% per year in the 2003-2007 period. Electricity throughput to Hydro One's distribution customers was 4% higher in 2007 than in 2006, and 2% lower in 2006 than in 2005, illustrating the impact weather can have on consumption and distribution revenues.

Customer concentration risk is not a credit factor. The diversity of Hydro One's customer base supports the overall stability of its revenues and limits exposure to any particular customer or customer class. Net revenues are comparable for transmission (52%) and distribution (48%). LDCs across the province, including that of Hydro One, collect transmission revenues from all customer classes and forward them to Hydro One through the Independent Electricity System Operator (IESO). The company's distribution operations collects its distribution revenues from a customer base that is about 51% residential, about 34% commercial, 6% large industrial, and 9% embedded LDCs (on a revenue basis).

Low-risk transmission and distribution dominate operations

Hydro One's low-risk transmission and distribution businesses dominate its operations. The performance of the LDC's regulated retail obligation does not contribute meaningfully to earnings or credit risk. Energy costs are a pass-through to consumers with no markup. The company does not engage in commodity price or volume risk management; it simply purchases energy from the IESO-administered spot market. During each quarter, the Ontario Power Authority (OPA), an agency of the provincial government, supports any variance between the amount collected from consumers and the amount paid by the LDCs to the IESO. The variance is recouped or rebated through rates in the following fiscal quarter through the OEB-regulated retail price.

The operational performance of the company's transmission assets is good; the system achieved top-quartile transmission reliability compared with other large Canadian peers, as reported to the Canadian Electricity Association. The electricity market rules and transmission license governing Hydro One's transmission operations require Hydro One to comply with reliability standards established by the North American Reliability Council, that include manageable monetary penalties for non compliance.

The distribution business' reliability is consistently lower than other rated LDC peers in Ontario largely because of the nature of Hydro One's service territory. Most of the LDCs peers have largely high density, urban territories, while Hydro One's rural LDC has a low customer density, with significant tree trimming requirements and more exposure to winter and summer storms. These operational challenges adversely affect the LDC's reliability. This has not posed an extraordinary risk to cash flows to date, given that the regulator is aware of the issues and reflects related expenses in the application of its cost-of-service regime.

Challenging capital program

Hydro One's capital expenditure will be higher than usual for the next several years. Transmission system spending to improve reliability, through maintenance and new developments, could amount to C$2.5 billion in the 2008-2010 period. On the distribution side, Hydro One will spend its C$2 billion planned capital program in the same period on new connections, smart meters, storm damage repairs, wood pole replacements and overall system reinforcement. We do not expect the company to undertake any major, multiyear projects without previous regulatory approval.

Weather-induced increases and reductions in energy delivered should not affect long-term credit quality. Hydro One's cash flows are subject to modest fluctuations. The transmission tariff is levied on the basis of monthly peak load; the distribution tariff is levied on a mix of fixed- and variable-charges for numerous customer classes. The company and the regulator are simplifying the distribution tariff classifications. Hydro One has recourse to the regulator if tariff design hampers their ability to, on average, recover the approved revenue requirement during a period of several years.

A medium-to-long-term risk to Hydro One's business and financial profiles is the impact of potential, large-scale, rationalization within the Ontario LDC sector in the coming years. Although not viewed as an immediate issue for the rating, Hydro One's expected active participation in such a scenario could present financing, execution, and integration risks.

Labor force demographics unfavorable

Hydro One faces labor demographics that, if not well managed, could pose a material risk to the company's day-to-day operations, and the implementation of its most ambitious capital program in two decades. Furthermore, if the regulator does not fully recognize related increases in labor expense, profitability could be negatively affected. Management's strategy is to address this through effective knowledge transfer to new hires, encouraging employee retention, and partnership with educational institutions. The company expects 30% of its workforce to depart in the next few years. This is a North America-wide phenomenon, making it that much more difficult to manage.

Asset-intensive nature of Hydro One's monopoly business reduces competitive risk

Although some competitive pressures exist, Hydro One's natural monopoly transmission system is largely shielded from direct competition. The company does not hold a legal monopoly on its service territory and there is no restriction on other transmission businesses building and operating transmission networks in Ontario; however, the company's cost-reflective pricing and the capital cost involved in large-scale duplication of the network reduce the risk of bypass. Furthermore, the OEB-approved uniform transmission pricing across Ontario mitigates the risk of bypass from competing transmitters, and should a bypass occur, tariffs would be rebalanced across remaining customers with minimal financial impact on the company. Of greater concern is Hydro One's exposure to the risk of lost revenue from embedded generation arising from high wholesale electricity prices.

Noncontiguous service territories of LDCs expose the company to competition for new services in nondesignated areas adjacent to its distribution service territories. The issue presents a competitive challenge for the company, but an OEB decision in mid-2004 would appear to limit the risk to greenfield development at the border of existing service territories and not put at risk cash flows secured by Hydro One's existing network.

Financial Policy

Hydro One's financial policies are prudent and consistent. Total leverage may exhibit slight modulations over a period of several years but is generally maintained close to the regulatory deemed structure. Debt maturities are well spread. Interest rate exposure is managed through the use of derivative instruments in a nonspeculative manner. The company is not exposed to foreign currency risk other than through the purchase of materials. It pays cash dividends on common shares based on a calculation involving its regulated net income net of preferred dividends and nonregulated net income. Common dividends historically have represented 60%-65% of net income. The preferred dividends of C$1.275 per share are stipulated in the company's articles of incorporation. Although the board of directors declares dividend on Hydro One's common and preferred shares, the shareholder agreement requires the company to consult with its owner, the province, regarding dividend payments.

Hydro One's current shortfall in its pension fund is manageable. We expect the company to contribute an estimated C$94 million per year in 2008 and 2009. The OEB regulatory regime recognizes pension costs as a prudent component of the total cost-of-service and as such they are largely recovered through regulated rates.

Hydro One has an enterprise-wide approach to risk management that is directed at balancing its regulatory, strategic, operational and financial risk exposure, and the returns allowed within the Ontario regulatory framework.

Financial Risk Profile

Accounting

Hydro One's consolidated financial statements are prepared in accordance with Canadian GAAP. The Canadian Accounting Standards Board has called for a convergence to International Financial Reporting Standards (IFRS) by 2011 and Hydro One began its preparations in 2006. The change in accounting practice should not affect our credit analysis even though using IFRS will likely result in a higher degree of fluctuation in Canadian regulated utilities reported net income than seen under Canadian GAAP.

Canadian GAAP allows utilities to defer costs or revenues that they expect the regulator will incorporate into future rates to the balance sheet. IFRS does not allow for the recognition of these regulatory assets and liabilities. Instead, costs are charged to the income statement when incurred and recoveries from customers are recognized when receivable. Assets and liabilities are recouped from or rebated to customers over periods typically varying from 1-4 years. To date, regulatory disallowances for assets and liabilities declared by Hydro One and other Ontario-based utilities have been minor. Nevertheless, accumulating significant regulatory assets or liabilities could indicate deteriorating regulatory support and as such we monitor the timeliness of recovery, closely. Hydro One's net regulatory liabilities as of Dec. 31, 2007, were C$370 million and, although significant, are not a rating concern.

We have made material adjustments to the balance sheet related to Hydro One's postretirement benefit obligations, and negligible operating lease adjustments (see table 1). Given the perpetual nature of transmission and distribution utility assets, it is a generally accepted practice in Canada that asset retirement obligations cannot be reasonably estimated since asset retirement dates cannot be pinpointed. We expect that the cost of disposing of regulated assets would likely be recouped through regulated revenues in advance of the retirement date.

Standard & Poor's treats Hydro One's C$323 million, 5.5% cumulative preferred shares as equity. The shares are held by the province, and are entitled to an annual cumulative dividend of 5.5% or C$18 million. To date, the preferred dividends have not been deferred. The shares are redeemable; however, Hydro One may, at its own discretion, pay all or part of the redemption price in common shares. The shares carry voting rights under limited circumstances and rank in priority above the common shares upon liquidation. The company is authorized to issue an unlimited number of preferred and common shares.

The adjusted interest coverage ratios (see tables 2 and 3) reflect interest expense that includes amortization of a refinancing discount. As of 2007, this amortization expense was only C$5 million or less than 2% of total interest expense. In 2006 and 2005, the amortization expense, of C$27 million and C$58 million respectively, represented about 9% and 18% of total interest expense. As part of our analytical considerations we considered the cash cost of the interest paid after removal of the amortization expense from the interest expense in those years.

Hydro One has C$133 million of goodwill on its balance sheet that the OEB does not recognize in its regulated rate base to determine electricity tariffs. The amount has not been impaired since the acquisitions occurred and is not material to our analysis. The goodwill arose when Hydro One acquired LDCs in excess of their fair value.

Table 1

Reconciliation Of Hydro One Inc. Reported Amounts With Standard & Poor's Adjusted Amounts*

	—Fiscal year ended Dec. 31, 2007—								
Hydro One Inc. reported amounts (mil. C$)	***Debt***	***Shareholders' equity***	***Operating income (before D&A)***	***Operating income (before D&A)***	***Operating income (after D&A)***	***Interest expense***	***Cash flow from operations***	***Cash flow from operations***	***Capital expenditures***
Reported	5,615.0	4,886.0	1,420.0	1,420.0	899.0	300.0	1,021.0	1,021.0	1,091.0
Standard & Poor's adjustments									
Operating leases	13.4	N/A	5.5	0.8	0.8	0.8	4.7	4.7	4.9
Postretirement benefit obligations	684.2	(355.2)	85.0	85.0	85.0	N/A	17.9	17.9	N/A
Capitalized interest	N/A	N/A	N/A	N/A	N/A	24.0	(24.0)	(24.0)	(24.0)
Reclassification of nonoperating income (expenses)	N/A	N/A	N/A	N/A	5.0	N/A	N/A	N/A	N/A
Reclassification of working-capital cash flow changes	N/A	N/A	N/A	N/A	N/A	N/A	N/A	(135.0)	N/A
Total adjustments	697.5	(355.2)	90.5	85.8	90.8	24.8	(1.4)	(136.4)	(19.1)
Standard & Poor's adjusted amounts	***Debt***	***Equity***	***Operating income (before D&A)***	***EBITDA***	***EBIT***	***Interest expense***	***Cash flow from operations***	***Funds from operations***	***Capital expenditures***
Adjusted	6,312.5	4,530.8	1,510.5	1,505.8	989.8	324.8	1,019.6	884.6	1,071.9

*Hydro One Inc. reported amounts shown are taken from the company's financial statements but might include adjustments made by data providers or reclassifications made by Standard & Poor's analysts. Please note that two reported amounts (operating income before D&A and cash flow from operations) are used to derive more than one Standard & Poor's-adjusted amount (operating income before D&A and EBITDA, and cash flow from operations and funds from operations, respectively). Consequently, the first section in some tables may feature duplicate descriptions and amounts. D&A—Depreciation and amortization. N/A—Not applicable.

Regulatory directives constrain profitability

Regulatory directives largely dictate Hydro One's maximum profitability. Tariffs are based on a forward year revenue requirement that should allow the company to earn a modest return on a deemed capital structure of 60% debt and 40% equity. The equity returns allowed are within the range, but at the low end, of international benchmarks. They are determined by a formula, in place since 1998, which provides some predictability. The formula is linked to the Government of Canada's long-term borrowing rate plus a modest equity risk premium. All else being equal, a one percent change in the ROE allowed in rates could affect the transmission annual net income assumption used in the setting of rates by about C$20 million and distribution annual net income by about C$13 million.

Further constraining profitability are new regulatory restrictions on overearning. Unlike its distribution network business, which has typically not earned its allowed ROE, the company's transmission business has historically achieved more than its allowed ROE. Until recently, it was allowed to retain these overearnings. In 2006, however, the regulator introduced an earnings sharing mechanism for the transmission business only and Hydro One must split excess transmission earnings on a 50-50 basis with the customer base.

Introducing annual automatic rate increases during longer periods between full rate base resetting hearings provides an opportunity for the distribution business to improve its profitability. It will be a challenge, however, given that each rate increase also includes a regulatory expectation of a 1% efficiency improvement. To date, on a consolidated basis, Hydro One has earned close to its allowed ROE.

The company's actual transmission monthly revenue is determined by the tariff rate multiplied by the actual sustained peak demand in each month. There is, therefore, a degree of seasonal and weather-related variability in revenue but it is easily managed and not a key rating factor. The same conclusion can be drawn with regards to operating costs and capital program execution, also largely due to seasonal and weather-related fluctuations.

Cash flow predictable but insufficient to fully fund larger-than-usual capital program

Cash flow is predictable and supported by regulation. Hydro One's annual FFO of close to C$900 million should cover expected dividend payments of close to C$300 million and part of the company's capital expenditure program in 2008. The company's annual capital expenditure should hover above the C$1 billion dollar mark for the next few years and will require partial debt funding. Net cash flow-to-capital expenditure should remain below 80% for some time.

Given the delay between capital spending and recovery through rates that is inherent in the OEB regulatory framework, Hydro One's cash flow credit and debt metrics will temporarily decline during a multiyear period of significant asset growth and renewal. AFFO-to-debt should remain above 10% but AFFO interest cover could fall below 3x depending on the timing dynamics of capital execution and regulatory rate base adjustment and tariff approvals. Rates are based on forward test years and, as such, the regulatory scrutiny of capital programs occurs prior to spending. Nevertheless, there could be negative rating consequences if this period of weaker cash flow strength persists beyond two or three years.

Liability management and liquidity

Hydro One's debt portfolio is well managed. The company has, as of March 31, C$400 million-C$600 million in maturing debt in each year from 2008-2012. This substantial amount of refinancing, combined with new issuance required to fund capital spending, should be manageable, given the company's historical easy access to the capital markets. About half of Hydro One's C$5.6 billion debt outstanding as of Dec. 31, 2007, had a maturity date of more than 10 years. No single year debt maturity exceeds 15% of the company's total long-term debt, but maturities remain lumpy. The company targets a weighted-average term of 12-18 years for its debt portfolio. All debt is unsecured and supported by a negative pledge.

Hydro One's leverage, as measured by total debt-to-total capital, had declined modestly but consistently each year, to 58% in 2007 from 63% in 2004. Total adjusted debt fluctuated between C$6.2 billion-C$6.3 billion during this period. We expect debt levels to increase by as much as C$700 million in both 2008 and 2009 if planned capital spending is approved by the regulator and implemented. Leverage should therefore move closer to historic levels, however, we expect that Hydro One will target 60% or better in the long term.

By law, Hydro One's LDC must procure electricity on behalf of nonregulated electricity retailers and LDC's embedded within Hydro One's system, for resale to their customers. The company manages this credit risk through service agreements that require counterparties to post various forms of collateral.

Hydro One manages interest rate and foreign exchange exposure. The company generally maintains less than 20% of debt (including debt maturing within the year) at floating rates and carries no material foreign exchange exposure, with all debt in Canadian dollars. The weighted-average coupon rate of Hydro One's debt at year-end 2007 was 5.7% slightly higher than 5.6% in 2005. The utility uses derivative financial instruments and interest rate swap contracts primarily to manage their exposure to interest rate fluctuations. Credit risk is managed by dealing primarily with highly-rate counterparties. Using master agreements that allow for net settlements reduces exposure to large collateral calls.

Hydro One's credit agreement has no material adverse change clauses that could trigger default but does limit debt to less than 75% of the company's total capitalization, and limits unregulated subsidiaries to less than 10% of total asset base.

Limited financial flexibility derived from government shareholder

Given the company's close relationship with its owner, the lack of diversity of Hydro One's funding sources is not a ratings concern. Supporting the company's financial flexibility are its ease of access to the debt capital markets and bank debt, and an ability to defer a portion of capital expenditure. Maturing debt is to be financed through the company's C$2.5 billion medium-term note shelf program. As of March 31, 2008, C$1.65 billion capacity remained available until July 2009. The company also has access to bank facilities largely for general corporate purposes and as a backup to its C$1 billion CP program. Hydro One can defer about C$200 million of forecast capital expenditure per year.

In times of financial duress, the government shareholder is a further potential source of financing and backup liquidity. Access to new equity in the form of cash injections from the shareholder is unlikely, but partial or full reduction or deferral of annual common dividend payments of as much as C$300 million (equivalent to the company's annual interest expense), mitigates this financing constraint somewhat. The government shareholder does not rely on the dividend payments.

Table 2

*Hydro One Inc.—Peer Comparison**

Industry Sector: Electric Utility

	—Average of past three fiscal years—			
(Mil. C$)	***Hydro One Inc.***	***Toronto Hydro Corp.***	***Hamilton Utilities Corp***	***Hydro Ottawa Holding Inc.***
Rating as of July 21, 2008	A+/Stable/A-1	A/Stable/—	A+/Stable/—	A/Stable/—
Revenues	4,538.7	2,416.3	546.3	691.2
Net income from cont. oper.	445.7	80.4	11.6	18.3
Funds from operations (FFO)	907.7	236.2	37.1	56.4
Capital expenditures	841.3	219.4	32.1	72.1
Cash and short-term investments	0.0	330.6	44.2	0.1
Debt	6,262.4	1,336.1	115.3	253.2
Preferred stock	323.0	0.0	0.0	0.0
Equity	4,175.5	868.5	214.7	276.4
Debt and equity	10,437.8	2,204.6	329.9	529.6
Adjusted ratios				
EBIT interest coverage (x)	3.0	2.6	3.7	3.3
FFO interest coverage (x)	3.4	3.5	4.9	5.3
FFO/debt (%)	14.5	17.7	32.2	22.3
Discretionary cash flow/debt (%)	(2.8)	(4.3)	(4.0)	(9.9)
Net cash flow/capex (%)	69.6	83.3	65.5	67.1
Total debt/debt plus equity (%)	60.0	60.6	34.9	47.8
Return on common equity (%)	9.0	9.1	6.6	6.7
Common dividend payout ratio (unadjusted; %)	73.0	66.5	113.5	43.8

*Fully adjusted (including postretirement obligations).

Table 3

*Hydro One Inc.—Financial Summary**

Industry Sector: Electric Utility

	—Fiscal year ended Dec. 31—				
(Mil. C$)	***2007***	***2006***	***2005***	***2004***	***2003***
Rating history	A/Positive/A-1	A/Stable/A-1	A/Stable/A-1	A/Stable/A-2	A-/Negative/A-2
Revenues	4,655.0	4,545.0	4,416.0	4,153.0	4,058.0
Net income from continuing operations	399.0	455.0	483.0	407.0	396.0
Funds from operations (FFO)	884.6	908.8	929.7	891.7	797.5
Capital expenditures	1,071.9	790.9	661.1	705.6	586.0
Debt	6,312.5	6,255.9	6,218.7	6,231.2	5,907.1
Preferred stock	323.0	323.0	323.0	323.0	323.0
Equity	4,530.8	4,226.3	3,769.3	3,610.5	3,507.0
Debt and equity	10,843.3	10,482.1	9,988.0	9,841.7	9,414.1
Adjusted ratios					
EBIT interest coverage (x)	3.0	3.1	2.9	2.7	2.6
FFO interest coverage (x)	3.7	3.5	3.0	3.0	2.6
FFO/debt (%)	14.0	14.5	15.0	14.3	13.5
Discretionary cash flow/debt (%)	(6.0)	(5.2)	2.8	(1.8)	1.8
Net cash flow/capex (%)	52.2	70.7	96.6	88.8	94.5
Debt/debt and equity (%)	58.2	59.7	62.3	63.3	62.7
Return on common equity (%)	7.9	9.0	10.1	9.0	9.2
Common dividend payout ratio (unadjusted; %)	87.1	76.0	58.7	63.5	59.8

*Fully adjusted (including postretirement obligations).

Ratings Detail (As Of 21-Jul-2008)*	
Hydro One Inc.	
Corporate Credit Rating	A+/Stable/A-1
Commercial Paper	
Local Currency	A-1
Canadian National Scale Commercial Paper Rating	A-1(MID)
Senior Unsecured (16 Issues)	A+
Corporate Credit Ratings History	
03-Jun-2008	A+/Stable/A-1
26-Mar-2007	A/Positive/A-1
15-Jul-2005	A/Stable/A-1
22-Apr-2004	A/Stable/A-2
03-Mar-2004	A-/Watch Dev/A-2
Debt Maturities	
2008 C$540 million 2009 C$400 million 2010 C$400 million 2011 C$250 million 2012 C$600 million 2013 and beyond C$3,425 million Note: As of Dec. 31, 2007.	
Related Entities	
Ontario Power Generation Inc.	
Issuer Credit Rating	BBB+/Positive/—
Commercial Paper	
Local Currency	A-2
Canadian National Scale Commercial Paper Rating	A-1(LOW)
Ontario (Province of)	
Issuer Credit Rating	AA/Stable/A-1+
Commercial Paper	A-1+
Canadian National Scale Commercial Paper Rating	A-1(HIGH)
Senior Unsecured (217 Issues)	AA

*Unless otherwise noted, all ratings in this report are global scale ratings. Standard & Poor's credit ratings on the global scale are comparable across countries. Standard & Poor's credit ratings on a national scale are relative to obligors or obligations within that specific country.

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Attachment 2

STANDARD
&POOR'S

COMMENTARY REPORT

Hydro One Inc.

***Primary Credit Analyst*:**
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Publication Date
Nov. 17, 2008

Rationale

The ratings on Hydro One Inc., a large, regulated transmission and local electricity distribution company (LDC) in the Province of Ontario (AA/Positive/A-1+), reflect the company's low-risk monopoly electricity transmission and distribution networks, secure and relatively predictable regulated cash flows, and the support of its owner, the province. In Standard & Poor's Ratings Services' opinion, offsetting its excellent business risk profile is an intermediate financial risk profile that will face the challenge of a large capital expenditure program in the next several years. The company had C$5.6 billion in debt outstanding as of Sept. 30, 2008.

Hydro One's monopoly position, the business' asset-intensive nature, and regulatory oversight limit competitive risk. It owns and operates more than 96% of the province's transmission network as measured by revenue, and its distribution network service territory covers about 75% of the province. Both the electricity transmission and distribution business carry relatively low operating risk, and exhibit average operational efficiency and reliability. We view the transmission operations as lower risk than distribution.

The Ontario Energy Board's (OEB) regulatory framework supports Hydro One's cash flow stability. The framework allows for the recovery of prudent transmission and distribution costs and the opportunity to earn a modest return. Regulatory cost recovery is generally predictable and timeliness is improving. Furthermore, in the current environment, the LDC's exposure to commodity risk is limited and the transmission provider has none. Although the LDC must bill electricity customers for the commodity delivered, the cost is a flow-through. The company has no obligation to ensure an adequate supply of electricity and is not burdened with the procurement process or power purchase agreements. Net distribution and transmission revenues are subject to modest volumetric risk due to weather. There is no near-term expectation of energy policy or electricity market framework initiatives that would affect the regulatory environment or the company's credit quality.

Hydro One has an intermediate financial risk profile that we believe could weaken during the buildout of the regulated asset base in the next two-to-three years. The extent of the temporary decline in the utility's cash flow strength will depend largely on timing of regulatory approvals and execution of planned capital expenditures, the impact of weather on revenue net of commodity costs, and the company's ability to find operating efficiencies sufficient to offset the OEB's performance-based pressures on rates. Adjusted funds from operation (AFFO) interest coverage was 3.7x as of Dec. 31, 2007 and 3.9x on a rolling 12-month basis as of Sept. 30, 2008. All else being equal, interest coverage could fall to closer to 3x due to delayed cash recovery from assets under construction without impinging on the rating, largely because of the business' regulated monopoly nature and Hydro One's government shareholder relationship. AFFO-to-total debt could decline to about 12% compared with the 2007 level of 14%. As of Sept. 30, it remained at about 14% on a rolling 12-month basis.

Hydro One's leverage, as measured by adjusted total debt-to-total capital, is also likely to temporarily creep back up to the historical level of about 64%, compared with 58% in 2007. Although partially funded from internal sources (about 50%), we believe capital spending during the next few years will be a drain on the company's cash flow, reducing financial flexibility and pressuring cash flow coverage. The utility budgeted C$1.4 billion in capital expenditure for 2008 but had only spent C$835 million as of Sept. 30 (62% of plan). The company estimates its 2009 capital program at more than C$1.5 billion. For several years, capital spending will be higher than the historical average of about C$700 million in the 2002-2006 period.

The transmission system requires upgrades and expansion to accommodate new and retiring generation, increased imports and exports, and modest growth in domestic demand. The 2008 and 2009 capital programs also include part of the estimated remaining C$670 million investment that Hydro One will make in smart meters for all distribution customers under a provincial directive by 2010.

The province's ownership of Hydro One enhances the utility's credit quality. Although Ontario does not formally guarantee the company's debt obligations, Hydro One's strategic nature within the provincial economy and the government's demonstrated willingness to assist the business (with liquidity support) under extraordinary circumstances in the past bode well for similar future support.

Short-term credit factors

The short-term rating on Hydro One is 'A-1'. Unused and committed bank lines, together with strong cash flow from operations and access to debt capital markets, provide Hydro One with sufficient liquidity and the financial flexibility to meet the company's estimated capital expenditure of more than C$1.5 billion in 2009, annual dividend payments of C$250 million-C$290 million, and C$400 million of debt maturing in February 2009. Furthermore, the company remains well within its banking covenant of total debt-to-total capital of 75% and has no material adverse change clauses that could trigger a default.

To support liquidity, the company can draw on:

- A committed C$1 billion bank line (maturing August 2010), of which C$840 remained available to support C$95 million in letters of credit outstanding as of Sept. 30. The bank line is used for general corporate purposes and to support Hydro One's C$1 billion Canadian commercial paper program, of which C$160 million was outstanding at third-quarter end;

- Annual regulated cash flows, as represented by unadjusted FFO, estimated at about C$900 million in 2008 and 2009;
- A medium-term note shelf program, maturing in July 2009, with C$1.15 billion remaining capacity as of Nov. 14, 2008;
- Discretionary capital expenditure estimated at more than C$200 million in 2008 and in 2009.

The company provides the Independent Electricity System Operator (IESO) with C$325 million in parental guarantees in lieu of prudential support. If all credit ratings on Hydro One were to fall below 'AA-', the IESO's prudential requirements would likely increase.

Outlook

The stable outlook reflects Hydro One's excellent business risk profile, which mitigates financial pressures of a larger-than-normal capital spending program. An adverse regulatory ruling or market restructuring (such as the assumption of the obligation to supply) could lead to a negative rating action. An upgrade is unlikely without the assurance of a much stronger balance sheet, and deeper cash flow-interest and -debt coverage. A significant change in the relationship with the government shareholder could move the rating up or down, but likely not more than a notch given the company's underlying credit strength.

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Attachment 3

STANDARD &POOR'S

Global Credit Portal

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October 29, 2009

Research Update:

Hydro One Inc. 'A+' Ratings Affirmed Despite Ontario Downgrade; Outlook Stable

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Research Update:

Hydro One Inc. 'A+' Ratings Affirmed Despite Ontario Downgrade; Outlook Stable

Overview

- We have affirmed our 'A+' long-term corporate credit rating on Hydro One Inc.
- Our view that there is a "high" likelihood that the shareholder (the Province of Ontario [AA-/Stable/A-1+]) would provide timely and sufficient extraordinary support in the event of financial distress has not changed despite our downgrade on the province Oct. 29, 2009.
- A negative outlook on the province would likely result in a negative outlook on Hydro One. A further one-notch downgrade on the province would affect the ratings on Hydro One, but likely not more than one notch given the company's underlying credit strength.

Rating Action

On Oct. 29, 2009, Standard & Poor's Ratings Services affirmed its ratings, including its 'A+' long-term corporate credit rating, on electricity transmitted and distributor Hydro One Inc. The outlook is stable.

Rationale

We affirmed the ratings despite our downgrade on the utility's owner, the Province of Ontario (AA-/Stable/A-1+), Oct. 29, 2009. Our view that there is "high" likelihood the province would provide timely and sufficient extraordinary support in the event of financial distress has not changed.

In Standard & Poor's opinion, the ratings on Hydro One, a large, regulated transmission and local electricity distribution company in Ontario, reflect the company's low-risk monopoly electricity transmission and distribution assets, secure and relatively predictable regulated cash flows, and the support of its owner, the province. We believe the utility has an excellent business risk profile and view its financial risk profile as intermediate. The utility had C$6.3 billion in long-term debt outstanding as of June 30, 2009.

We base the 'A+' rating on Hydro One on the company's stand-alone credit risk profile (SACP) and our opinion that there is "high" likelihood that the province would provide timely and sufficient extraordinary support in the event of financial distress. We assess Hydro One's stand-alone credit risk profile at 'A'. We view the company's role as "important" to the province and the link between Hydro One and the province as "very strong".

In our view, the company has an intermediate financial risk profile. Relative to other corporate entities, Hydro One's financial risk profile is characterized by strong access to capital markets, adequate liquidity,

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stability and predictability of its cash flow, and low merger and acquisition risk. We expect the company will manage the current cycle of regulated rate base growth such that the balance sheet will not exceed 65% adjusted total debt-to-capital. As of June 30, 2009, on a rolling 12-month basis, adjusted FFO (AFFO) interest coverage was 3.9x and AFFO-to-total debt was 13.5%, which we consider weak but expect will remain stable, consistent with the past several years.

Short-term credit factors

The short-term rating on Hydro One is 'A-1'. In our opinion, unused and committed bank lines, together with cash flow from operations and demonstrated access to debt capital markets, provide the utility with sufficient liquidity and the financial flexibility to meet the company's capital plans, maturing debt obligations, and dividends in 2009. The company remains well within its banking covenant of total debt-to-total capital of 75% and has no material adverse change clauses that could trigger a default.

Nevertheless, Hydro One could be free operating cash-flow negative by, we believe, about C$600 million due to its capital program's above-average size and depending on dividend payouts. To support liquidity, the utility can draw on a committed C$1 billion bank line (maturing August 2010), which remains largely available, to support its C$1 billion Canadian commercial paper program. Discretionary capital expenditures, which we estimate at about C$500 million in 2009, contribute to the company's financial flexibility. Hydro One has a C$3 billion medium-term note shelf program maturing in August 2011.

Outlook

The stable outlook reflects Hydro One's consistent performance and our expectation of predictable regulatory support. A material, adverse regulatory ruling or market restructuring (such as the assumption of the obligation to supply, not just deliver, electricity) could lead to a negative rating action. An improvement in Hydro One's SACP is unlikely without the assurance of a much stronger balance sheet, and deeper cash flow-interest and -debt coverage. All else being equal, a negative outlook or further downgrade on the province would affect the rating on Hydro One, but likely not more than a notch, given the company's underlying credit strength. Finally, a change in the relationship with the province could also move the rating.

Related Research

- "Enhanced Methodology And Assumptions For Rating Government-Related Entities," June 29, 2009
- "Criteria Methodology: Business Risk/Financial Risk Matrix Expanded," May 27, 2009

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Ratings List

Ratings Affirmed

Hydro One Inc.	
Corporate credit rating	A+/Stable/A-1
Senior unsecured debt	A+
Commercial paper	
Global scale	A-1
Canada scale	A-1(Mid)

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Attachment 4

DBRS

Insight beyond the rating.

Rating Report

Report Date:
April 16, 2009

Previous Report:
November 15, 2007

Hydro One Inc.

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The Company

Hydro One Inc., through its wholly owned subsidiaries, owns and operates electric power transmission and distribution assets, as well as a fibre-optic network, across most of Ontario. Hydro One is the largest transmission and distribution operator in Ontario (servicing more than 95% of the province's transmission throughput). It is wholly owned by the Province of Ontario (rated AA).

Commercial Paper:
Authorized Limit of $1 Billion

Recent Actions

March 2, 2009
Rates $300 Million Issue A (high)

January 12, 2009
Rates $200 Million Issue A (high)

Rating

Debt Rated	Rating	Rating Action	Trend
Commercial Paper	R-1 (middle)	Confirmed	Stable
Senior Unsecured Debentures	A (high)	Confirmed	Stable

Rating Rationale

DBRS has confirmed the Senior Unsecured Debentures rating of Hydro One Inc. (Hydro One or the Company) at A (high) and its Commercial Paper at R-1 (middle), both with Stable trends. The rating confirmations reflect Hydro One's low level of business risk, stemming from its regulated electric power transmission and distribution operations, and its solid financial profile, underpinned by its robust balance sheet and strong credit metrics.

The Company's largest challenge over the medium term continues to be its significant ongoing capital expenditures and the resultant free cash flow deficits. Capital expenditures are expected to exceed $4.8 billion over the next three years. As a result, DBRS expects annual capital expenditures to average between $1.5 billion and $1.7 billion, which, combined with dividends, could exceed operating cash flows by approximately $700 million to $900 million per year. The capital expenditures are primarily reflecting investments to expand, refurbish or replace transmission infrastructure, which is consistent with government policy, the planning information (including the Integrated Power System Plan (IPSP)) of the Ontario Power Authority (OPA), local supply requirements and the preventive and corrective maintenance needs to manage aging assets. The level of investment also reflects the continued mass deployment of smart meters within Hydro One's distribution businesses, which began in 2007 and will be completed by the end of 2010. (Continued on page 2.)

Rating Considerations

Strengths

(1) Low-risk, regulated electric power transmission and distribution businesses
(2) Solid balance sheet and credit metrics
(3) Strong and extensive transmission and distribution franchise area
(4) Top quartile for transmission reliability

Challenges

(1) Substantial capital expenditure program
(2) Significant external financing required
(3) Approved return on equity (ROE) sensitive to interest rates
(4) Earnings sensitive to monthly peak demand for electricity and, to a lesser extent, to the volume of electricity sold
(5) Lack of access to equity capital markets

	For the year ended December 31				
(CAD millions)	2008	2007*	2006	2005	2004
Cash flow from operations	927	1,006	930	945	920
EBIT gross interest coverage (1)	2.68	2.83	2.77	2.78	2.63
Fixed charge coverage (1)	2.50	2.59	2.57	2.59	2.44
Total adjusted debt-to-capital (%) (1)	55.2%	54.2%	53.3%	52.6%	54.3%
Cash flow-to-total adjusted debt (1)	0.149	0.176	0.171	0.183	0.174
Cash flow/capital expenditures (times)	0.72	0.92	1.13	1.37	1.27
Gross free cash flow	(616)	(410)	(225)	(19)	(54)
Return on average equity (before non-recurring items) (%)	10.7%	8.7%	9.8%	10.8%	10.1%
Approved ROE - Distribution	8.57%	9.00%	9.00%	9.88%	9.88%
Approved ROE - Transmission	8.35%	8.35%	9.88%	9.88%	9.88%

(1) DBRS-adjusted for operating lease debt and interest expense equivalents. DBRS-adjusted for preferred shares (20% debt/ 80% equity).

* DBRS adjusted Transmission earnings for non-cash items to normalize impact from OEB rate decision.

Hydro One Inc.

Report Date:
April 16, 2009

Rating Rationale (Continued from page 1.)

The free cash flow deficits are expected to be entirely debt financed, which will put temporary pressure on the Company's balance sheet and coverage ratios as the invested capital is not included in the rate base until the completion of the projects. Also, given that a material portion of Hydro One's capital expenditures are for large transmission projects that involve lengthy construction times and the potential for delays caused by the intervenor process, timely project completion within budget is important to maintain the Company's financial health.

On the regulatory front, Hydro One submitted a transmission rate application for 2009 and 2010 in September 2008. The application seeks Ontario Energy Board (OEB) approval for revenue requirements of approximately $1.2 billion for 2009 and $1.34 billion for 2010, based on ROE of 8.53% and 9.35%, respectively. The Company anticipates a decision in the summer of 2009.

DBRS believes that Hydro One's operations will be relatively stable going forward, given the regulated environment in which it operates and the strong growth in the size of the Company's rate base. DBRS anticipates a number of Hydro One's regulatory-approved capital projects to be completed and in service in the coming years, thereby increasing the rate base further and, subsequently, its earnings profile.

DBRS views the expected pressure on the Company's earnings and balance sheet as temporary and expects Hydro One's financial metrics to remain within a range supportive of the assigned ratings, given its low level of business risk, solid financial profile, strong balance sheet and experienced management team.

Rating Considerations Details

Strengths

(1) Hydro One is a regulated electric power transmission and distribution utility. As such, the Company's business risk profile is low for the following reasons: (a) Hydro One can recover all prudently incurred operating costs and approved capital project costs within a reasonable time frame as revenue requirements are predetermined based on forward-looking cost of service; (b) the Company will not undertake large capital expenditures without a reasonable expectation of recovering them in its rates; and (c) the regulatory environment continues to become more transparent with respect to the regulatory treatment of equity thickness and ROE methodology. DBRS believes that the OEB will be supportive in the recovery of capital costs as well as operating expenses that are necessary for a safe and reliable electricity system.

(2) Hydro One's credit metrics remain solid for an A (high) regulated utility: the debt-to-capital ratio is 55.2%, EBIT-to-interest coverage is 2.68 times and cash flow-to-debt is 14.9%. Although DBRS expects coverage ratios to continue to experience modest downward pressure in the near to medium term, given the lower approved revenue requirements for its transmission business, coupled with higher overall capital expenditures driving sizable free cash flow deficits, the Company's financial metrics are expected to remain within a range that is consistent with its business risk level and the assigned ratings.

(3) Hydro One owns and operates substantially all of Ontario's electric power transmission system and is linked to five adjoining jurisdictions, accommodating imports of about 4,000 megawatts (MW) and exports of approximately 5,800 MW of electricity. The Company's distribution system is the largest in Ontario and spans roughly 75% of the province, serving approximately 1.3 million rural and urban customers and 110 large industrial customers. The large geographic area and low population density translates into a higher rate of service for its distribution business relative to other electric power distribution companies.

(4) Hydro One's transmission business continues to achieve top quartile reliability measures, which should continue to facilitate a healthy relationship with the regulator.

Challenges

(1) Hydro One is currently in the midst of an aggressive build-out program that will continue over the next several years and, DBRS expects, will result in a measurable increase in capital investment from present levels to a range of $1.5 billion to $1.7 billion per year through 2011. This, combined with dividends, is expected to cause a cash flow deficit of an estimated $700 million to $900 million per annum. These sizable free cash flow deficits, combined with lengthy construction times, will put temporary pressure on the balance sheet and coverage ratios during the build-out. DBRS notes that capital projects are spread out over time, which helps to minimize liquidity issues that accompany such large projects. The size and magnitude of Hydro One's upcoming designated projects (e.g., the Bruce Project, estimated at $620 million), combined with the continued increases in material and labour costs and the significant number of intervenors involved, could potentially expose Hydro One to rising project costs beyond the amount forecast in its regulatory applications. There is no assurance that cost overruns beyond the regulatory-approved amounts will be recovered if deemed imprudent by the OEB. However, DBRS notes that Hydro One is experienced in managing projects and is focused on mitigating the risk of cost overruns.

(2) Hydro One will have to go to the debt markets to fund its significant free cash flow deficits and refinance a heavy-but-manageable debt repayment schedule over the medium term. Maintaining adequate access to the public debt market and adequate availability under its credit facility ($1 billion) is important during this build-out period.

(3) Regulatory-approved ROE levels are low and could continue to trend lower if long-term interest rates decline. Approved ROE for the transmission operation declined to 8.35% for 2008. For 2009, the ROE for the transmission segment continues to be 8.35% until the OEB renders its decision on the Company's transmission rate application for 2009 and 2010 in the summer of 2009. The company has requested an ROE of 8.53% and 9.35% for 2009 and 2010, respectively. The distribution segment witnessed a decline in ROE to 8.57% for 2008 and 2009 from 9.00% in 2007.

(4) Earnings and cash flows for the transmission segment and, to a lesser extent, distribution operations are sensitive to monthly peak demand and volume of electricity sold given that rates typically include a variable-rate component. Seasonality, economic cyclicality, weather patterns and Conservation Demand Management (CDM) programs directly affect the volume of electricity sold or peak monthly electrical demand and, therefore, revenue earned from electricity sales.

(5) Because Hydro One is owned by the province, it is unable to access the equity capital markets. This limits the Company's financial flexibility as free cash flow deficits will likely be financed through its $1 billion commercial paper (CP) program (fully backstopped by a credit facility) or debt issuance under its $2.5 billion medium-term notes (MTNs) program. Also, the Company has historically paid out a high level of dividends (a five-year average of 64% of net income). Given the increasing liquidity requirements, DBRS anticipates some dividend management may be required going forward as Hydro One is committed to investing heavily in its electricity system.

Regulation

Hydro One's electric power distribution operations are regulated by the OEB under the *Ontario Energy Board Act*, 1998 (the OEB Act) as modified by the following noteworthy amendments:

- The *Electricity Pricing, Conservation and Supply Act*, 2002 (Bill 210) – December 9, 2002.
- The *Ontario Energy Board Amendment Act* (Electricity Pricing), 2003 (Bill 4) – December 18, 2003.
- The *Electricity Restructuring Act*, 2004 (Bill 100) – December 9, 2004.

Currently, the capital structure and ROE methodology used by the OEB to establish transmission and distribution rates is based on a deemed debt-to-equity structure of 60%-40% and the forecast long-term Canada bond interest rate.

Transmission
In August 2007, the OEB reduced Hydro One's base transmission rates, retroactive for the period January 1, 2007, to December 31, 2008, resulting in an approximately 7% reduction in base revenue requirements relative to F2006 net revenues. The methodology used by the OEB to establish the transmission rates was based on a rate base of $6,344 million ($5,718 million from 2000 to 2006), a deemed debt-to-equity structure of 60%-40%, an approved weighted-average debt rate of 5.80% and an allowed ROE of 8.35%. Also, the OEB approved Hydro One's operations, administration and capital expenditure budgets, along with the expensing and recovery of the carrying costs of the Niagara Reinforcement Project until the project is completed and placed into service; however, the OEB did not approve the request for allowing certain capital expenditures into rate base before project completion. New transmission rates are retroactive to January 1, 2007, and were implemented on November 1, 2007 (with $85 million recovered from January 1, 2007, to October 31, 2007, and allocated back on a monthly basis).

Hydro One submitted a transmission rate application for 2009 and 2010 in September 2008. The application seeks Ontario Energy Board (OEB) approval for revenue requirements of approximately $1.2 billion in 2009 and $1.34 billion in 2010 based on ROE of 8.53% and 9.35%, respectively. Hydro One's transmission forecast rate base for the 2009 test year is $7,033.8 million and for the 2010 test year $7,650.5 million. The Company anticipates a decision in the summer of 2009.

Distribution
Hydro One is one of more than 80 electric power distributors in Ontario, which are regulated by the OEB. In 2006, the OEB issued a 2007 rate adjustment model (second generation Incentive Regulation Mechanism (IRM) and cost of capital) and corresponding instructions to distributors for the purpose of adjusting distributor rates effective May 1, 2007. Under that plan, all electric power distributors are to have rates set based on a cost-of-service rate filing in one of 2008, 2009 or 2010. Accordingly, Hydro One filed a cost-of-service application based on 2008 as the forward test year.

Hydro One's distribution business operates under a performance-based incentive mechanism, with a deemed ROE of 8.57% and an OEB deemed capital structure of 60% debt and 40% equity.

In November 2007, Hydro One Brampton filed its application for 2008 rates on the basis of the OEB's cost of capital and second generation IRM policies. On March 19, 2008, the OEB released its decision regarding the 2008 rate application, approving the submission on the basis of its cost of capital and second generation IRM policies. The revised rates, including the continuation of the charge of 67 cents per month per metered customer for smart meters, were approved, with an implementation date of May 1, 2008. The overall impact on an average residential customer's total bill is a decrease of about 3%. On January 29, 2009, the OEB issued a letter proposing that the distribution rates of Hydro One Brampton be re-based in 2011.

On December 18, 2008, the OEB issued a decision approving substantially all work program expenditures effective May 1, 2008, for implementation on February 1, 2009. The OEB also approved recovery of the Company's smart meter expenditures made prior to the end of 2007. Subsequent expenditures will continue to be tracked in deferral accounts for future recovery. The decision approved the establishment of the Revenue Recovery Account (RRA) to record the revenue differential between existing distribution rates and new rates. The RRA will be recovered over a 27-month period, commencing February 1, 2009, and ending April 30, 2011.

In September 2008, the OEB finalized the third generation IRM formula, which adjusts rates by considering inflation, productivity targets, significant events outside the control of management and a capital adjustment mechanism to recover costs for new incremental capital coming in service beyond a prescribed threshold. Hydro One Networks filed its IRM application for 2009 rates in late 2008. An update was submitted in January 2009 to reflect the impact of the 2008 distribution rate decision. The application seeks an approximate 4% increase in 2009 distribution rates, effective May 1, 2009. These increases are expected to affect an average residential customer's total bill by less than 1.5%, assuming non-distribution charges remain unchanged.

Earnings and Outlook

Segmented Information		For the year ended December 31				
(CAD millions)		2008	2007 *	2006	2005	2004
Net revenues						
Transmission	50.2%	1,212	1,242	1,245	1,310	1,262
Distribution	47.7%	1,153	1,142	1,052	954	910
Other	2.1%	51	31	27	21	17
Total net revenues		**2,416**	**2,415**	**2,324**	**2,285**	**2,189**
EBIT by segment						
Transmission	63.2%	571	585	614	711	665
Distribution	37.1%	335	320	323	305	284
Other	-0.3%	(3)	(6)	(8)	(10)	(11)
Total EBIT		**903**	**899**	**929**	**1,006**	**938**

Income Statement	For the year ended December 31				
(CAD millions)	2008	2007 *	2006	2005	2004
Net revenues	2,416	2,415	2,324	2,285	2,189
OM&A expense	965	995	880	792	771
EBITDA	1,451	1,420	1,444	1,493	1,418
EBIT	903	899	929	1,006	938
Interest expense (1)	333	312	307	303	294
Core net income (before non-recurring items and prefs)	498	399	455	483	430
Reported net income (after prefs)	497	402	437	465	480
Operating margin	37%	37%	40%	44%	43%
Return on average equity (before non-recurring items)	10.7%	8.7%	9.8%	10.8%	10.1%

(1) Interest expense on short-term and long-term debt balances, excludes deferred financing charges.

* DBRS adjusted Transmission earnings for non-cash items to normalize the impact from the recent OEB rate decision.

Summary

Revenues and EBIT remained flat for 2008. Net income of $498 million was $99 million, or 25%, more than in 2007. The increase is attributable primarily to the reduction in payments in lieu of corporate income taxes, resulting from a lower effective tax rate and other net temporary differences. Additionally, lower operation, maintenance and administration expense positively affected earnings; however, these effects were partially offset by reduced transmission revenues.

Transmission revenues declined $30 million, or 2%, from 2007, mainly due to lower average monthly peak demands experienced during the year. Overall average annual load was lower in 2008, which resulted in lower revenues of $66 million. This was partially offset by higher revenues associated with exporting electricity to other jurisdictions, higher ancillary transmission revenues and higher other revenues of $6 million, primarily associated with regulatory accounts. The OEB's August 2007 transmission rate decision also affected the Company's revenues when it reduced ROE from 9.88% to 8.35%. As a result, the Company witnessed a reduction in transmission revenues of $128 million compared with 2007. That impact was offset by adjustments to earned revenue that were previously recorded as reductions to the earnings-sharing mechanisms and revenue difference deferral account (RDDA).

Distribution revenues decreased by $48 million in 2008 compared with 2007. The decrease is a result of lower purchased power costs, lower consumption as a result of unfavourable weather conditions and lower revenues from the recovery of a distribution-related regulatory account, which ceased in March 2008.

Interest expense has incrementally trended upward, largely tracking higher debt levels.

Overall, earnings remain robust and relatively stable as Hydro One continues to earn its allowed ROE, underscoring continued focus on productivity and cost-effectiveness.

Hydro One Inc.

Report Date:
April 16, 2009

Outlook

DBRS expects EBIT and net income to continue to grow over the medium term, driven primarily by a number of regulatory-approved transmission projects that are expected to be completed and in service in 2009, thereby increasing the rate base and, subsequently, Hydro One's earnings profile. Furthermore, in 2009, Hydro One is expecting to have the OEB issue its decision on the transmission rate filing.

Despite the growth in revenues and earnings, key credit metrics are expected to decline modestly over the medium term before showing improvement, primarily as a result of increased debt levels and free cash flow deficits as capital expenditures increase in the medium term.

Financial Profile

Statement of Cash Flow	For the year ended December 31				
(CAD millions)	2008	2007	2006	2005	2004
Core net income, (before non-recurring, after pfd.)	498	399	437	465	412
Depreciation & amortization	502	482	474	446	446
Amortization of debt re-couponing	0	5	27	58	62
Other recurring non-cash items	(73)	120	(8)	(24)	0
Cash Flow from Operations	**927**	**1,006**	**930**	**945**	**920**
Capital expenditures	(1,284)	(1,091)	(823)	(691)	(727)
Common dividends	(259)	(325)	(332)	(273)	(247)
Free Cash Flow before Working Capital Changes	**(616)**	**(410)**	**(225)**	**(19)**	**(54)**
Change in working capital	128	135	(92)	194	(33)
Net Free Cash Flow	**(488)**	**(275)**	**(317)**	**175**	**(87)**
Other investments/acquisitions/disposition	(3)	8	15	9	19
Other non-recurring, incl. retail settlement variance	0	0	40	2	6
Cash flow before financing	**(491)**	**(267)**	**(262)**	**186**	**(62)**
Net debt financing	510	285	246	(188)	83
Equity financing	0	0	0	0	0
Other financing	9	(1)	(4)	2	7
Net change in cash	28	17	(20)	0	28
Total adjusted debt (CAD millions) (1)	6,240	5,710	5,427	5,156	5,293
Cash flow gross interest coverage (1)	3.76	4.21	4.01	4.10	4.11
Fixed charges coverage (times) (1)	2.50	2.59	2.57	2.59	2.44
Total adjusted debt-to-capital (%) (1)	55.2%	54.2%	53.3%	52.6%	54.3%
Cash flow/total adjusted debt (1)	0.149	0.176	0.171	0.183	0.174
Cash flow/capital expenditures (times)	0.72	0.92	1.13	1.37	1.27
Dividend payout ratio	52.0%	81.5%	73.0%	56.5%	49.6%

(1) DBRS-adjusted for operating lease debt and interest expense equivalents. DBRS-adjusted for preferred shares (20% debt/ 80% equity).

Summary

Cash flow from operations decreased by $79 million from 2007 results to $927 million. The decrease, which is attributable to the repayment to customers of amounts recorded in the RDDA established following the transmission rate decision last year, was offset by higher net income and depreciation.

Growth in sustaining and development capital spending, combined with dividends, continues to drive up net free cash flow deficits. The Company has historically proven that it can effectively manage the substantial size of its capital expenditure programs. However, the recent upward trend in capital investment reflects investments to expand, refurbish or replace transmission infrastructure, which is consistent with government policy, OPA planning information (including the IPSP), local supply requirements and the preventive and corrective maintenance needs to manage aging assets. These investments are indicative of the growing need in Ontario for reliable electricity as a number of Hydro One's assets come to the end of their useful life and new power generation needs to be connected to the grid. Additionally, the increased capital expenditures reflect the continued mass deployment of smart meters in the Company's distribution businesses. The smart meter initiative will be completed by the end of 2010.

Key credit metrics declined modestly as the large ongoing capital expenditure program has caused a continuation of free cash flow deficits, which have been entirely debt financed, thus increasing debt levels and interest expense. DBRS notes that the Company has a reasonable financial profile, reflecting a solid and stable balance sheet. The credit metrics remain solidly within the current rating category for a low-risk regulated utility with debt-to-capital at 55.2%, fixed charge coverage at 2.50 times and cash flow-to-debt at 0.149 times.

Outlook

Free cash flow deficits are expected to persist over the medium term, attributable to the large capital expenditures program. Annual capital expenditures are expected to remain high, with approximately $4.8 billion in projects planned over the next three years, which means the Company will have significant financing requirements. DBRS believes that the Company will finance the resultant free cash flow deficits with incremental debt; therefore, continued access to capital markets is critical for Hydro One. DBRS does not expect Hydro One to have difficulty accessing the capital markets, even during these uncertain market conditions. However, if Hydro One is temporarily delayed in accessing the markets for longer-term debt, the Company should be able to finance its obligations with its $1 billion CP program, which is fully backstopped by a credit facility.

DBRS notes that common dividends are declared at the sole discretion of the Hydro One board of directors and are recommended by management based on financial conditions and liquidity requirements, which should provide some flexibility for dividend management as the Company is committed to investing heavily in its electricity system.

As such, the Company's leverage is expected to increase over the medium term as the substantial capital expenditure program and dividend payment will result in sizable free cash flow deficits. These deficits and the subsequent higher leverage in the capital structure will temporarily pressure key credits from present levels. DBRS does not expect the Company's financial profile to change significantly, with credit metrics remaining adequate for the assigned ratings.

Capital Expenditures: Designated Projects

Designated Projects	**Historic**	**Bridge**	**Test**	**Total**	
(CAD millions)	**2005-2007**	**2008**	**2009-2010**	**(including future years)**	**%**
Bruce Project	7.8	30.9	433.4	619.8	21%
Quebec Intertie	75.2	35.7	11.9	122.8	4%
Total other projects*	470	196.8	895.6	2058.2	71%
Niagara Reinforcement	97		2	101	3%
Total	**650**	**263.4**	**1342.9**	**2901.8**	**100%**

* Development Capital Projects in Excess of $3 Million

Source: 2009/2010 Transmission Revenue Requirement & Rate Application (EB-2008-0272), D1-03-03_-_Development_Capital.

The Québec Interconnection project, a collaboration between Hydro One and Hydro-Québec, will allow the transfer of 1,250 MW between the two provinces when it is completed in early 2009. The Hydro One and Hydro-Québec grids are not synchronous, so for power to be exchanged it must be converted to the requirements of the receiving grid. The total estimated project cost is $808 million, of which $115 million is earmarked for Hydro One's capital budget.

The Bruce to Milton, Ontario, project was approved by the OEB in the EB-2007-0050 proceeding. It is a 500 kilovolt (kV), 180-kilometre transmission line project that will connect the Bruce Power nuclear plants on Lake Huron to the Milton switching station west of Toronto. The proposed project could serve to deliver up to an additional 3,000 MW of capacity. The project is expected to be completed in mid-2010 to late 2011.

Long-Term Debt Maturities and Bank Lines

Long-term principal repayments as at December 31, 2008		
Year	%	(CAD millions)
2009	6.5%	400
2010	8.2%	500
2011	8.2%	500
2012	9.8%	600
2013	6.5%	400
Thereafter	60.8%	3,725
Total		6,125

* Amount refinanced in early 2009

(CAD millions) As at December 31, 2008	Committed	Outstanding	Available	Maturity
Commercial Paper backup facility*	1,000	0	1,000	8/10/2010

* Multi year revolving standby credit facility with a syndicate of banks.

Long-Term Debt

Hydro One finances its operations and capital programs with long-term debt ($6,125 million senior unsecured debt as at December 31, 2008) and a $1 billion CP program (fully backed up by a credit facility). Hydro One has $2.4 billion maturing in the next five years. Refinancing the debt should be well within its financing capacity given its solid financial profile and good access to the public debt markets. Although Hydro One has historically targeted a weighted-average long-term debt life of between 12 and 18 years, current market conditions have prompted the Company to issue shorter-dated maturities. However, the recent issuances are not substantial and should be easily refinanced upon maturity.

Hydro One's long-term financing is provided primarily through its MTN program. The maximum authorized principal amount of MTNs issuable under this program until July 2009 is $2,500 million, of which $1,150 million was remaining and available as at December 31, 2008. In early 2009, the Company issued $600 million under the MTN program, thus leaving only $550 million available as at March 31, 2009.

The Trust Indenture pertaining to all senior unsecured issuance includes the following covenants, subject to customary exceptions:
- Any additional indebtedness is subject to a 75% capitalization ratio test.
- Negative pledge clause.
- Limitations on ability to sell principal properties.

Liquidity

Liquidity requirements will increase over the medium term to accommodate higher capital expenditures and regulatory working capital needs. DBRS notes that Hydro One has sufficient flexibility to accommodate the increasing liquidity needs, with its authorized CP program and availability under its MTN program. As of December 31, 2008, the Company had no outstanding amounts under the credit facility. Hydro One's board has authorized a CP limit of $1 billion. Previously, the Company had set the limit of its CP program at $750 million, matching the limit of the revolving credit facility. However, in January 2008, the Company increased the total program to $1 billion. As a result, the credit facility was also increased from $750 million to $1 billion. The credit facility is a multi-year facility that matures in 2010.

Hydro One Inc.

Report Date:
April 16, 2009

Hydro One Inc.

Balance Sheet

(CAD millions)

Assets	2008	2007	2006	Liabilities & Equity	2008	2007	2006
	As at December 31				As at December 31		
Cash + short-term investments	16	-	-	Short-term debt	0	12	89
Accounts receivable	754	759	777	L.t. debt due one year	400	540	395
Material, supplies & other	101	143	69	A/P + accr'ds	898	900	710
Current Assets	871	902	846	**Current Liabilities**	1,298	1,452	1,194
Net fixed assets	12,119	11,258	10,526	Long-term debt	5,733	5,063	4,848
Post-employment benefits	441	380	382	Post-employ. benefits	908	855	803
Def'd debt costs + long-term rec.	21	7	12	L.t. pay. + other liab.	813	530	544
Regulatory asset	291	106	311	Preferred shares	323	323	323
Goodwill	133	133	133	Shareholders' equity	4,801	4,563	4,498
Total	13,876	12,786	12,210	**Total**	13,876	12,786	12,210

Ratio Analysis

Liquidity Ratios	2008	2007*	2006	2005	2004	2003
	For the year ended December 31					
Current ratio	0.67	0.62	0.71	0.52	0.60	0.55
Cash flow/total debt (1)	0.149	0.176	0.171	0.183	0.174	0.166
Total adjusted debt-to-capital (1)	55.2%	54.2%	53.3%	52.6%	54.3%	55.0%
Cash flow/capital expenditures	0.72	0.92	1.13	1.37	1.27	1.43
Cash flow-dividends/capital expenditures	0.52	0.62	0.73	0.97	0.93	1.05
Adj. total debt/EBITDA (1)	4.30	4.02	3.76	3.45	3.73	3.71
Hybrids in capital structure	2.9%	3.1%	3.2%	3.3%	3.3%	3.4%
Deemed common equity	40.0%	40.0%	36.0%	36.0%	36.0%	36.0%
Common dividend payout (before extras.)	54.0%	85.3%	76.0%	58.7%	60.0%	59.8%
Coverage Ratios						
EBIT gross interest coverage (1)	2.68	2.83	2.77	2.78	2.63	2.49
EBIT net interest coverage (1)	3.08	3.04	3.14	3.09	2.83	2.69
EBITDA gross interest coverage (1)	4.31	4.46	4.31	4.12	3.97	3.70
EBITDA net interest coverage (1)	4.94	4.79	4.87	4.58	4.27	3.98
Fixed-charges coverage (1)	2.50	2.59	2.57	2.59	2.44	2.34
Earnings Quality/Operating Efficiencies & Statistics						
Operating margin	37.4%	37.2%	40.0%	44.0%	42.9%	42.9%
Net margin (before non-recurring, after pfd.)	20.7%	16.4%	18.8%	20.4%	18.8%	17.3%
Return on avg. equity (before non-recurring items)	10.7%	8.7%	9.8%	10.8%	10.1%	9.7%
Approved ROE (Distribution)	8.57%	9.0%	9.0%	9.88%	9.88%	9.88%
Approved ROE (Transmission)	8.35%	8.35%	9.88%	9.88%	9.88%	9.88%
Rate base - distribution ($ millions)	4,247	3,711	3,711	2,637	2,637	2,637
Rate base - transmission ($ millions)	6,657	6,344	5,718	5,718	5,718	5,718
Transmission throughputs (TWh)	148.7	152.2	151.1	157.0	153.4	151.7
Distribution throughputs (TWh)	29.9	30.2	29.0	29.7	28.5	27.9
Average annual 60-minute peak demand (MWh)	21,820	22,988	27,005	26,160	24,979	24,753

(1) DBRS-adjusted for operating lease debt and interest expense equivalents. DBRS-adjusted for preferred shares (20% debt/ 80% equity).

* DBRS adjusted Transmission earnings for non-cash items to normalize the impact from the recent OEB rate decision.

Hydro One Inc.

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Rating

Debt Rated	Rating	Rating Action	Trend
Commercial Paper	R-1 (middle)	Confirmed	Stable
Senior Unsecured Debentures	A (high)	Confirmed	Stable

Rating History

	Current	2008	2007	2006	2005
Commercial Paper	R-1 (middle)	R-1 (middle)	R-1 (middle)	R-1 (middle)	R-1 (low)
Senior Unsecured Debentures	A (high)	A (high)	A (high)	A (high)	A

Related Research

- DBRS Rates Issue of $300 Million, 6.03% Medium Term Notes at A (high), March 2, 2009.
- DBRS Rates Issue of $200 Million, 5.00% Medium Term Notes at A (high), January 12, 2009.
- DBRS Rates Hydro One's Issue of $400 Million, 5.00% Medium Term Notes at A (high), November 5, 2008.
- DBRS Rates Issue of $300 Million 5.18% Medium-Term Notes at A (high), February 29, 2008.
- DBRS Rates Issue of $250 Million, 4.08% Medium Term Notes at A (high), February 29, 2008.

Note:
All figures are in Canadian dollars unless otherwise noted.

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Attachment 5

Moody's Investors Service

Global Credit Research
Credit Opinion
27 APR 2009

Credit Opinion: Hydro One Inc.

Hydro One Inc.

Toronto, Ontario, Canada

Ratings

Category	Moody's Rating
Outlook	Stable
Senior Unsecured -Dom Curr	Aa3
Commercial Paper	P-1

Contacts

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Key Indicators

Hydro One Inc.

	2008	2007	2006	2005	2004
(CFO Pre-W/C + Interest) / Interest Expense (x) [1]	**3.6x**	**4.1x**	**3.9x**	**3.4x**	**3.4x**
(CFO Pre-W/C) / Debt (%) [1]	**14.4%**	**17.7%**	**18.1%**	**16.7%**	**15.9%**
(CFO Pre-W/C - Dividends) / Debt (%) [1]	**10.6%**	**12.2%**	**12.2%**	**12.0%**	**11.7%**
Debt / Book Capitalization (%)	**59.5%**	**55.2%**	**58.3%**	**61.1%**	**62.6%**

[1] CFO pre-W/C, which is also referred to as FFO in the Global Regulated Electric Utilities Rating Methodology, is equal to net cash flow from operations less net changes in working capital items

Note: For definitions of Moody's most common ratio terms please see the accompanying User's Guide.

Opinion

Rating Drivers

Relatively large, low-risk regulated electricity T&D utility with no commodity price risk. Operates in a relatively supportive regulatory environment.

Stable and predictable cash flows but credit metrics expected to weaken further and remain significantly weaker than other A-rated, low-risk T&D utilities in the short-term.

Low allowed ROE, continuing elevated capital expenditures and under-funded pension plan have depressed credit metrics.

Sufficient liquidity has been maintained through frequent and sizeable debt capital market issuances.

Aa3 rating reflects HOI's baseline credit assessment in the 5 to 7 range, high default dependence and high probability of extraordinary support in context of the Province of Ontario's Aa1 rating.

Corporate Profile

Headquartered in Toronto, Ontario, Hydro One Inc. (HOI) is a commercial corporation, 100% owned by the Province of Ontario. Virtually all of HOI's revenues and cash flows are derived from its electricity T&D businesses, both of which are regulated by the Ontario Energy Board (OEB). HOI owns and operates virtually all of Ontario's electricity transmission system, and is responsible for a substantial portion of regulated electricity distribution in Ontario.

SUMMARY RATING RATIONALE

HOI's Aa3, stable senior unsecured rating reflects its baseline credit assessment (BCA) in the 5 to 7 range, high default dependence and high probability of extraordinary support in context of the Province of Ontario's Aa1 rating. HOI's A-category BCA reflects the company's low-risk business model as a cost of service-regulated electricity T&D utility with no commodity price risk exposure. HOI's financial profile is weak relative to other A-rated low risk electric utilities and is expected to weaken further due to the combination of low allowed ROEs and ongoing high levels of capital spending. The weakening of HOI's credit metrics in 2008 reflects continued high spending on capital projects. These projects generate little or no cash flow until completed and placed into service. In addition, HOI's adjusted leverage rose in 2008 because, like many other companies, HOI incurred significant losses on its pension plan assets. Moody's expects that HOI's financial profile should recover modestly in two to three years' time as major capital projects are completed and capital spending moderates and as pension funding improves with the anticipated recovery of financial asset values and ongoing pension contributions. However, HOI's BCA could come under pressure if the anticipated improvement in financial metrics fails to materialize.

DETAILED RATING CONSIDERATIONS

RATING METHODOLOGY FOR GOVERNMENT RELATED ISSUERS

In accordance with Moody's Government Related Issuer (GRI) rating methodology, HOI's Aa3 rating reflects the combination of the following inputs:

Baseline Credit Assessment (BCA) in the 5 to 7 range (on a scale of 1 to 21, where 1 represents the equivalent risk of a Aaa, 2 a Aa1, 3 a Aa2 and so on).

Aa1 local currency rating of the Province of Ontario.

High default dependence.

High probability of extraordinary support.

HOI's high default dependence reflects HOI's exposure to virtually all facets of the provincial economy and its operational and financial proximity to the government. HOI's high probability of extraordinary support reflects the strategic importance of HOI to the Provincial economy, the Province's history of providing support through dividend deferrals as well as the Province's role as the architect of electricity policy and regulation and its history of intervention in the electricity sector. As a 100%-owned subsidiary of the Province, HOI can be utilized as an instrument of public policy. Moody's observes that public policy goals are not always completely aligned with the interests of debt holders.

HOI's BCA reflects the following:

LOW-RISK REGULATED ELECTRIC UTILITY OPERATING IN A RELATIVELY STABLE LEGISLATIVE BUT EVOLVING REGULATORY ENVIRONMENT

HOI is considered to be a low-risk utility given that its operations are almost exclusively T&D, its T&D assets are wholly regulated and all of its operations are located in Canada, a jurisdiction that Moody's generally views as being one of the more supportive regulatory environments for utilities on a global basis. Moody's considers the T&D segment to be a relatively lower risk segment of the electric utility industry since it is typically not exposed to commodity price and volume risks or the operational, financial and environmental risks that can be associated with electricity generation. Moreover, virtually all of HOI's activities are regulated with the exception of its telecommunications business, which represents less than 1% of total assets.

HOI falls under the jurisdiction of the OEB which regulates both the T&D segments of its business. The legislative environment in Ontario has been relatively stable since 2005 but the regulatory framework continues to evolve and thus experiences some regulatory lag. With the evolution of the regulatory environment, Moody's anticipates that there will be increased transparency and predictability for HOI after 2008 as distribution rates will be established pursuant to a formula driven mechanism under the OEB's 3rd Generation Incentive Regulation Model (IRM).

HOI's cash flow tends to be stable and predictable given its lack of commodity price exposure, nominal foreign exchange exposure and manageable exposure to floating interest rates. While HOI purchases power in its distribution segment, these commodity costs are a full pass-through to customers. In the transmission segment, HOI has no exposure to electricity prices. Like many cost of service utilities whose rates are established on a forward test year basis, HOI is exposed to a degree of forecast risk.

STABLE, PREDICTABLE CASH FLOW BUT KEY FINANCIAL METRICS SIGNIFICANTLY WEAKER THAN

THOSE OF A-RATED PEERS IN NEAR-TERM

While HOI's low-risk regulated business model generates stable and predictable funds from operations, Moody's expects HOI's financial metrics to weaken further in 2009 and be significantly weaker than other A-rated, low-risk electric utilities. HOI's financial metrics have always tended to be weaker than those of other A-rated international peers due to the relatively low allowed ROEs and deemed equity components common to Canadian regulated utilities. Historically, Moody's has considered this relatively weak financial profile to be balanced by HOI's low-risk business model and supportive regulatory and business environments. However, HOI is currently experiencing a cyclical peak in its capital spending which is further pressuring its credit metrics as capital is being deployed on assets that are not yet generating cash flows. Moody's anticipates that HOI's metrics could improve modestly in 2012 provided that capital spending moderates as expected. However, the company points out that the Province's proposed Green Energy and Green Economy Act, 2009 (Bill 150) could cause HOI's capital spending to remain elevated beyond 2011. If beyond 2011, HOI's capital spending remains elevated and its credit metrics do not improve, for instance (CFO pre-WC + Interest)/Interest of 4x or more and CFO pre-WC/Debt of 16% or more, HOI's BCA could be downgraded.

Liquidity Profile

LIQUIDITY ARRANGEMENTS SUFFICIENT BUT CONTINUE TO BE PRESSURED BY ELEVATED CAPITAL SPENDING

HOI's commercial paper (CP) program is rated Prime-1 (P-1) based on the stable cash flow generated by its regulated operations and alternative liquidity arrangements that are expected to be sufficient to meet the balance of HOI's 2009 funding requirements under Moody's liquidity stress scenario. Moody's liquidity stress scenario assumes that the company loses access to new capital, other than credit available under its committed credit agreements, for a period of 12 months.

HOI is currently experiencing a cyclical peak in its capital spending. High levels of capital spending stressed HOI's liquidity resources during the 2007 and 2008 and are expected to continue to do so at least until to the end of 2011. To date, HOI has managed this stress by regularly accessing the capital markets, including raising $500 million in November 2008 and a further $600 million in three offerings during in the first quarter of 2009. Given the expectation that capital spending will remain elevated through 2011, Moody's expects that HOI will continue to require regular access to the term debt markets in order to avoid curtailing its planned capital spending and dividends.

In support of the company's $1 billion CP program, HOI maintains a syndicated committed three year bank facility that matures on August 9, 2010. The facility contains a maximum debt to total capitalization ratio covenant of 75% but does not include funding inhibiting language such as an ongoing material adverse change clause. At December 31, 2008, it is estimated that HOI had access to the full amount of the bank facility less $111 million of outstanding letters of credit which, for analytical purposes, Moody's considers to be a use of HOI's committed credit facilities.

HOI is expected to generate approximately $890 million of adjusted FFO in 2009. After dividends, capital expenditures and working capital changes of approximately $1.8 billion, Moody's expects HOI to be FCF negative by approximately $870 million in 2009. Given scheduled maturities of $400 million in 2009, HOI's 2009 funding requirement was nearly $1.3 billion. However, the funding requirement for the balance of 2009 was reduced to approximately $700 million by the $600 million of MTNs issued by HOI in the first quarter of 2009. HOI's can issue up to $550 million under its existing MTN shelf which expires in July 2009.

Rating Outlook

HOI's rating outlook remains stable despite the expectation that, over the next 12 to 18 months, HOI's credit metrics will continue to be significantly weaker than those of other A-rated low-risk electric utilities. Moody's currently expects that HOI's metrics will exhibit some modest improvement in two to three years' time as capital spending moderates and as pension funding improves. The stable outlook reflects Moody's belief that HOI's low-risk business model and stable and predictable cash flows can accommodate the extended period of high capital spending and weaker credit metrics provided that HOI prudently manages its liquidity resources.

What Could Change the Rating - Up

Moody's considers an upward revision in HOI's rating to be unlikely in the near term. However, the company's BCA or published rating could be positively impacted if HOI could demonstrate a sustainable improvement in financial ratios, such as CFO pre-WC to Interest exceeding 6.0x, CFO pre-WC to Debt exceeding 30% and CFO pre-WC less Dividends to Debt exceeding 25%.

What Could Change the Rating - Down

HOI's BCA or published ratings could be negatively impacted by one or more of the following:

A material reduction in the perceived probability of extraordinary support.

A sustained weakening of cash flow metrics such as CFO pre-WC to Interest coverage below 4.0x, CFO pre-WC to Debt below 16% and/or CFO pre-WC less Dividends to Debt below 14.5%.

Failure of the company to ensure sufficient sources of liquidity in support of its growing capital expenditure program.

Actions on the part of the shareholder that impede the company's ability to act in a commercial manner.

Material changes in the ownership, governance or management structures.

Further restructuring of the electricity sector that increases HOI's business or financial risk profiles.

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APPENDIX AJ

Connection and Cost Recovery Agreement

between

Hydro One Brampton Networks Inc.

and

Hydro One Networks Inc.

for

Goreway TS Expansion

February 2008

Hydro One Brampton Networks Inc. (the "Customer") has requested and **Hydro One Networks Inc.** ("Hydro One") has agreed to build a new 230/27.6-27.6 kV, 75/100/125 MVA DESN (the "Project") on the terms and conditions set forth in this Agreement dated January 18, 2008 (the "Agreement") and the attached Standard Terms and Conditions for Low Risk Transmission Customer Connection Projects V3 09-2007 (the "Standard Terms and Conditions" or "T&C"). Schedules "A" and "B" attached hereto and the Standard Terms and Conditions are to be read with and form part of this Agreement.

Project Summary

The 27.6 kV loads in the East Brampton area are reaching transformation facilities' available capacity. The Customer has advised Hydro One that it will require new transformation capacity to supply 27.6 kV loads and has requested that Hydro One build a new 230/27.6-27.6 kV 75/100/125 MVA DESN at Hydro One's Goreway TS ("Goreway TS Expansion Project").

Term: The term of this Agreement commences on the date first written above and terminates on the 25th anniversary of the In Service Date.

Special Circumstances: The Customer acknowledges the station loading is limited by the 230 kV supply cables rating of 420 MVA based on single contingency.

In addition to the circumstances described in Section 5 of the Standard Terms and Conditions, the Ready for Service Date is subject to:

(a) the Customer executing and delivering this Agreement to Hydro One by no later than January 21, 2008, (the "Execution Date");

Subject to Section 31, this Agreement constitutes the entire agreement between the parties with respect to the subject matter of this Agreement and supersedes all prior oral or written representations and agreements concerning the subject matter of this Agreement.

IN WITNESS WHEREOF, the parties hereto have caused this Agreement to be executed by the signatures of their proper authorized signatories, as of the day and year first written above.

HYDRO ONE NETWORKS INC.

J. H. Patt

Jim Patterson
Manager - Customer Business Relations
I have the authority to bind the Corporation.

HYDRO ONE BRAMPTON NETWORKS INC.

Roger A. Albert

Roger Albert
President
I have the authority to bind the Corporation.

Schedule "A" *(Project Title)*

PROJECT SCOPE

New or Modified Connection Facilities: Hydro One will design, construct, own and operate a new 75/100/125 MVA, 230/27.6-27.6 kV DESN to be located at the existing Goreway TS site.

Connection Point: 230 kV transmission circuits, V73RS and V76R

Ready for Service Date: May 1, 2010

HYDRO ONE CONNECTION WORK

Part 1:Transformation Connection Pool Work

Hydro One will:

Hydro One will design and build a new 230/27.6-27.6 kV DESN at Goreway TS as described below:

1. General Requirements

- Obtain approvals and permits as required for the station facilities. These include, and are not necessarily limited to those related to noise, soil removals, drainage, and landscaping.
- Carry out acceptance checks, testing and commissioning of station equipment and associated systems.
- Revise drawings, as required.
- Provide landscaping as per City, zoning and other requirements.
- Expand the existing station fence.

2. 230 kV Switchyard

The new HV switchyard will be integrated into existing HV facilities. The scope of work includes the following:

- Modify the exiting 230 kV line entrance and buswork as required to accommodate connection to the new transformers.
- Provide and install two (2) 230 kV motorized disconnect switches to meet the requirements of the line tap and to interrupt the maximum transformer magnetizing current.
- Provide and install two (2) 75/100/125 MVA, 230/27.6-27.6 kV transformers with a minimum summer 10-day LTR of 170 MVA.
- Provide and install transformer coolers and conservator tanks.
- Provide and install spill containment around the two transformers.
- Provide and install six (6) HV station class surge arresters, one for each phase of the HV bushings.
- Provide and install all required insulators, support structures, foundations and 230 kV cabling connecting the above equipment.

3. 27.6 kV Switching Facilities

All electrical equipment in the 27.6 kV switchyard is to be installed in bays of outdoor switching structure. The LV switchyard will be designed to allow for underground egress of the twelve feeders. Scope of work includes the following:

- Provide and install twelve (12) LV station class surge arresters.
- Provide and install four (4) 1.5 ohm transformer neutral grounding reactors.
- Provide and install two (2) main buses.
- Provide and install four (4) LV transformer breakers each with two isolating switches.
- Provide and install one (1) bus-tie breaker with two isolating switches.

- Provide and install twelve (12) 1200 Ampere feeder breakers, each with six (6) isolating switches.
- Provide and install buses between the main buses and the feeder breakers and future capacitor breakers.
- Provide and install six (6) feeder tie switches.
- Provide and install twelve (12) potential transformers for protection purposes.
- Provide and install twelve (12) sets of feeder buses connecting the feeder breakers, the feeder tie switches and the Customer's feeders.
- Provide and install all required insulators, support structures, foundations and LV cabling connecting the above equipment.

4. AC and DC Station Service Systems

- Provide and install a complete AC Station Service System including two (2) pad-mounted Station Service Transformers with associated fusing, insulators, transfer switches, breakers, disconnect switches, panels and cabling.
- Provide a complete DC Station Service System along with 125 VDC sealed battery, charger, DC distribution panels and cabling.

5. Protection, Control and Teleprotections Systems

- Provide and install a pre-fabricated & pre-wired P&C building.
- Provide cross tripping facilities between the existing 27.6 kV and 44 kV DESNs and the new DESN and for the interface between the new facility and the existing line protection associated with circuits V73RS and V76R.
- Review and revise, as required, the line protections on V73RS and V76R at Rexdale TS, Sithe Goreway GS, Cardiff TS, Bramalea TS and the existing Goreway TS.
- Provide SCADA telemetry quantities to OGCC.
- Provide SCADA telemetry quantities to IESO.
- Provide under-frequency load shedding relay, as required.
- Witness P&C building manufacturer commissioning
- Commission all P&C devices associated with the new facilities as well as at existing facilities connected to 230 kV circuits, V73RS and V76R.

6. Grounding and Lightning Protection

- Provide and install station ground grid in the new switchyard.
- Provide grounding for the new sections of station fence.
- Provide standard grounding for the power transformers, HV and LV surge arresters, HV and LV switches, breakers and all steel structures.
- Provide perimeter grounding for the P&C building and connect to the grounding bus inside the P&C building.
- Review and upgrade lightning protection at the TS, as required.

7. Exclusions/Assumptions

Cost estimates are based on the following assumptions:

- There will be no requirement for Environmental Assessment.
- Noise assessment is required
- Geotechnical Investigation exists for the existing portion of the station and this estimate assumes the same soil conditions for the extension of the station
- Excavated soil is not contaminated.
- No 230 kV lines are involved in this work.

Part 2: Line Connection Pool Work

Hydro One will:

- Move the 230 kV underground termination facilities on the TS site to make room for the new 230 kV buswork extension to the DESN.

NOTE: Once this new DESN has been completed, the installed capacity for all DESNs at Goreway TS will exceed the capacity of the supply circuits (420 MVA), V73RS and V76R. When the combined loading on all DESNs at Goreway TS reaches the capacity of the supply circuits, transmission reinforcement will be required.

Part 3: Network Customer Allocated Work

Hydro One will:

- Review and revise, as required, the line protections on V73RS and V76R at Richview TS and Claireville TS

Part 4: Network Pool Work (Non-Recoverable from Customer)

Hydro One will:

- Not Applicable

Part 5: Work Chargeable to Customer

Hydro One will:

1. Revenue Metering Instrument Transformers

- Specify, supply, install and connect twelve (12) Revenue Canada approved revenue metering potential transformers (PTs) and twelve (12) free standing Revenue Canada approved revenue metering current transformers (CTs) on LV bus structures. The bus structure is to be modified to accommodate the installation.
- Provide four (4) metering junction boxes on the structure supporting the revenue metering CTs.
- Supply, install and terminate the secondary cables from the instrument transformer terminal boxes to metering junction boxes and to the metering cabinets provided by the Customer.
- Install and terminate 120 VAC Station Service cables from AC Station Service Distribution panel to the metering cabinets provided by the Customer.
- Install and terminate telephone service cables from telecom cable interface box to metering cabinets provided by the Customer.
- Install the structure supporting the Customer's metering cabinets to a location outside the P&C building.
- Providing spare instrument transformers are NOT included in the scope of work.

2. Feeder Duct Banks

- Expectation is that Hydro One will be asked by the Customer to provide and install feeder duct banks from the feeder breakers to just outside the station fence. This work is NOT covered by this agreement and will be dealt with by a separate agreement.

Part 6: Scope Change

For the purposes of this Part 6 of Schedule "A", the term "Non-Customer Initiated Scope Change(s)" means one or more changes that are required to be made to the Project Scope as detailed and documented in Parts 1 to 5 of this Schedule "A" such as a result of any one or more of the following:

- any environmental assessment(s);
- any IESO requirements identified in the System Impact Assessment or any revisions thereto.

Any change in the Project Scope as detailed and documented in Parts 1 to 5 of this Schedule "A" whether they are initiated by the Customer or are Non-Customer Initiated Scope Changes, may result in a change to the Project costs estimated in Schedule "B" of this Agreement and the Project schedule, including the Ready for Service Date.

All Customer initiated scope changes to this Project must be in writing to Hydro One.

Hydro One will advise the Customer of any cost and schedule impacts of any Customer initiated scope changes. Hydro One will advise the Customer of any Material cost and/or Material schedule impacts of any Non-Customer Initiated Scope Changes.

Hydro One will not implement any Customer initiated scope changes until written approval has been received from the Customer accepting the new pricing and schedule impact.

Hydro One will implement all Non-Customer initiated scope changes until the estimate of the Engineering and Construction Cost of all of the Non-Customer initiated scope changes made by Hydro One reaches 10% of the total sum of the estimates of the Engineering and Construction Cost of:

(i) the Transformation Connection Pool Work,;
(ii) the Line Connection Pool Work;
(iii) Network Pool Work
(iv) Network Customer Allocated Work; and
(v) the Work Chargeable to Customer.

At that point, no further Non-Customer initiated scope changes may be made by Hydro One without the written consent of the Customer accepting new pricing and schedule impact. If the Customer does not accept the new pricing and schedule impact, Hydro One will not be responsible for any delay in the Ready for Service Date as a consequence thereof.

CUSTOMER CONNECTION WORK

The Customer will:

- Provide and install four (4) Revenue Metering cabinets and associated metering equipment and cabling.
- Order a landline telephone service for IESO MV90 access and ensure that the service is available at least two weeks prior to in-service date.
- Accept responsibility for the registration of the revenue metering installations. The IESO registration work must be completed at least two weeks prior to the in-service date.
- Accept responsibility for purchasing any spare equipment associated with the revenue metering.
- Provide and install feeder duct banks outside the station fence.

- Provide and install 27.6 kV feeder cables and make connection to NEMA pads at feeder disconnect switch.

NOTES:

The Estimate of the Engineering and Construction Cost of the Transformation Connection Pool Work and the Estimate of Transformation Connection Pool Work Capital Contribution do not include any amounts associated with the easements and other land rights to be obtained by Hydro One from third parties for the Transformation Connection Pool Work. The actual cost of obtaining those easements and other land rights will be reflected in the Actual Engineering and Construction Cost of the Transformation Connection Pool Work and the Actual Transformation Connection Pool Work Capital Contribution.

EXISTING LOAD:

	A	B
Existing Load Facility	**Existing Load (MW)**[1]	**Normal Capacity (MW)**[2]
Goreway TS T5/T6	181	181
Bramalea TS[3]	82.5	82.5

Notes:

1. Existing Load (Annual Peak Load) means the Customer's Assigned Capacity at the Existing Load Facility as of the date of this Agreement (Section 3.0.3 of the *Transmission System Code).*
2. Any station load above the Normal Capacity of the Existing Load Facility (Overload) will be determined in accordance with Section 6.7.9 of the *Transmission System Code* and Hydro One's Connection Procedures. If the Overload is transferred to the New or Modified Connection Facilities, the Overload will be credited to the Line Connection Revenue, Transformation Connection Revenue or Network Revenue requirement, whichever is applicable.
3. The Customer utilises 82.5MW, which represents 50% of the total capacity at Bramalea TS.
4. Average monthly peak load will be calculated based on PLI of 0.78.

OTHER RELEVANT CONSIDERATIONS: NONE

EXCEPTIONAL CIRCUMSTANCES RE. NETWORK CONSTRUCTION OR MODIFICATIONS: (Yes/No). NONE

MISCELLANEOUS

Customer Connection Risk Classification: Low Risk

True-Up Points: **Low Risk** (a) following the fifth and tenth anniversaries of the In Service Date; and

(b) following the fifteenth anniversary of the In Service Date if the Actual Load is 20% higher or lower than the Load Forecast at the end of the tenth anniversary of the In Service Date.

Customer's GST Registration Number: 864867635RT0001

Documentation Required (after In Service Date): Final Feeder Egress Drawings

Ownership: Hydro One will own all equipment provided by Hydro One as part of the Hydro One Connection Work.

Approval Date (if Section 92 required to be obtained by Hydro One): N/A

Security Requirements: Specify amount or Nil

Security Date:

Easement Required from Customer: NO

Easement Date: N/A

Easement Lands: N/A

Easement Term: N/A

Approval Date (for OEB leave to construct):

Revenue Metering: IESO compliant revenue metering to be provided by the Customer

Customer Notice Info:

Hydro One Brampton Networks Inc.
175 Sandalwood Pkwy., West
Brampton, Ontario L7A 1E8

Attention: Roger Albert, President & CEO
Fax #: (905) 840-1305

Schedule "B" *(Project Title)*

TRANSFORMATION CONNECTION POOL WORK

Estimate of the Engineering and Construction Cost of the Transformation Connection Pool Work: $23,489,005.00

Estimate of Transformation Connection Pool Work Capital Contribution: $9,511,200.00

Actual Engineering and Construction Cost of the Transformation Connection Pool Work: To be provided 180 days after the Ready for Service Date

Actual Transformation Connection Pool Work Capital Contribution: To be provided 180 days after the Ready for Service Date

Capital Contribution Includes the Cost of Capacity Not Needed by the Customer:

LINE CONNECTION POOL WORK

Estimate of the Engineering and Construction Cost of the Line Connection Pool Work: $376,493.00

Estimate of Line Connection Pool Work Capital Contribution: N/A

Actual Engineering and Construction Cost of the Line Connection Pool Work: To be provided 180 days after the Ready for Service Date

Actual Line Connection Pool Work Capital Contribution: To be provided 180 days after Ready for Service Date

Capital Contribution Includes the Cost of Capacity Not Needed by the Customer:

NETWORK CUSTOMER ALLOCATED WORK

Estimate of the Engineering and Construction Cost of the Network Customer Allocated Work: $284,764.00

Actual Engineering and Construction Cost of the Network Customer Allocated Work: To be provided 180 days after Ready for Service Date

NETWORK POOL WORK (NON-RECOVERABLE FROM CUSTOMER):

The estimated Engineering and Construction Cost of the Network Pool Work (Non-Recoverable from Customer) is $0.00. Subject to Section 14.2 of the Standard Terms and Conditions, Hydro One will perform this work at its own expense.

WORK CHARGEABLE TO CUSTOMER

Estimate of the Engineering and Construction Cost of the Work Chargeable To Customer:

Revenue metering instrument transformers: $328,091.00

Cable duct banks: To be covered by a separate agreement

Actual Engineering and Construction Cost of the Work Chargeable to Customer: To be provided 180 days after Ready for Service Date

MANNER OF PAYMENT OF THE ESTIMATE OF CAPITAL CONTRIBUTIONS AND WORK CHARGEABLE TO CUSTOMER

The Customer shall pay Hydro One the estimate of the Transformation Connection Pool Work Capital Contribution, the Estimate of Line Connection Pool Work Capital Contribution, the estimate of the Network Customer Allocated Work Capital Contribution and the estimate of the Engineering and Construction Cost of the Work Chargeable to Customer by making the progress payments specified below on or before the Payment Milestone Date specified below. Hydro One will invoice the Customer for each progress payment 30 days prior to the Payment Milestone Date.

Payment Milestone Date	Transformation Pool Work Capital Contribution	Line Pool Work Capital Contribution	Network Customer Allocated Work Capital Contribution	Work Chargeable To Customer	Total Payment Required
Jan. 15, 2009	2,377,800.00	0	0	82,022.75	2,459,822.75
June 15, 2009	2,377,800.00	0	0	82,022.75	2,459,822.75
Jan. 15, 2010	2,377,800.00	0	0	82,022.75	2,459,822.75
June 15, 2010	2,377,800.00	0	0	82,022.75	2,459,822.75

TRANSFORMATION CONNECTION REVENUE REQUIREMENTS AND LOAD FORECAST AT THE NEW OR MODIFIED CONNECTION FACILITIES

Annual Period Ending On:	New Load** (MW) (1)	Part of New Load Exceeding Normal Capacity of Existing Load Facilities [A] (Note 1)	Adjusted Load Forecast (MW) [B]	Transformation Connection Revenue (k$) for True-Up, based on [A] or [B], whichever is applicable
1st Anniversary of In Service Date	18.6	18.6	18.6	359.3
2nd Anniversary of In Service Date	24.8	24.8	24.8	478.6
3rd Anniversary of In Service Date	30.5	30.5	30.5	589.8
4th Anniversary of In Service Date	36.4	36.4	36.4	704.2
5th Anniversary of In Service Date	42.6	42.6	42.6	822.1
6th Anniversary of In Service Date	48.8	48.8	48.8	943.5
7th Anniversary of In Service Date	55.3	55.3	55.3	1068.6
8th Anniversary of In Service Date	62.0	62.0	62.0	1197.4
9th Anniversary of In Service Date	68.8	68.8	68.8	1330.1
10th Anniversary of In Service Date	75.9	75.9	75.9	1466.8
11th Anniversary of In Service Date	83.2	83.2	83.2	1607.5
12th Anniversary of In Service Date	90.7	90.7	90.7	1752.5
13th Anniversary of In Service Date	98.4	98.4	98.4	1901.9
14th Anniversary of In Service Date	106.4	106.4	106.4	2055.7
15th Anniversary of In Service Date	114.3	114.3	114.3	2208.7
16th Anniversary of In Service Date	119.3	119.3	119.3	2305.6
17th Anniversary of In Service Date	119.3	119.3	119.3	2305.6
18th Anniversary of In Service Date	119.3	119.3	119.3	2305.6
19th Anniversary of In Service Date	119.3	119.3	119.3	2305.6
20th Anniversary of In Service Date	119.3	119.3	119.3	2305.6
21st Anniversary of In Service Date	119.3	119.3	119.3	2305.6
22nd Anniversary of In Service Date	119.3	119.3	119.3	2305.6
23rd Anniversary of In Service Date	119.3	119.3	119.3	2305.6
24th Anniversary of In Service Date	119.3	119.3	119.3	2305.6
25th Anniversary of In Service Date	119.3	119.3	119.3	2305.6

(1) Average monthly peak load for anniversary year, based on PLI of 0.78.

LINE CONNECTION REVENUE REQUIREMENTS AND LOAD FORECAST AT THE NEW OR MODIFIED CONNECTION FACILITIES

Annual Period Ending On:	New Load** - (MW) (1)	Part of New Load Exceeding Normal Capacity of Existing Load Facilities [C]	Adjusted Load Forecast (MW) [D]	Line Connection Revenue (k$) for True-Up, Based on [C] or [D], whichever is applicable
1st Anniversary of In Service Date	18.6	18.6	1.5	10.9
2nd Anniversary of In Service Date	24.8	24.8	2.0	14.4
3rd Anniversary of In Service Date	30.5	30.5	2.5	17.8
4th Anniversary of In Service Date	36.4	36.4	3.0	21.2
5th Anniversary of In Service Date	42.6	42.6	3.5	24.8
6th Anniversary of In Service Date	48.8	48.8	4.0	28.4
7th Anniversary of In Service Date	55.3	55.3	4.5	32.2
8th Anniversary of In Service Date	62.0	62.0	5.1	36.1
9th Anniversary of In Service Date	68.8	68.8	5.7	40.1
10th Anniversary of In Service Date	75.9	75.9	6.2	44.2
11th Anniversary of In Service Date	83.2	83.2	6.8	48.5
12th Anniversary of In Service Date	90.7	90.7	7.5	52.8
13th Anniversary of In Service Date	98.4	98.4	8.1	57.3
14th Anniversary of In Service Date	106.4	106.4	8.8	62.0
15th Anniversary of In Service Date	114.3	114.3	9.4	66.6
16th Anniversary of In Service Date	119.3	119.3	9.8	69.5
17th Anniversary of In Service Date	119.3	119.3	9.8	69.5
18th Anniversary of In Service Date	119.3	119.3	9.8	69.5
19th Anniversary of In Service Date	119.3	119.3	9.8	69.5
20th Anniversary of In Service Date	119.3	119.3	9.8	69.5
21st Anniversary of In Service Date	119.3	119.3	9.8	69.5
22nd Anniversary of In Service Date	119.3	119.3	9.8	69.5
23rd Anniversary of In Service Date	119.3	119.3	9.8	69.5
24th Anniversary of In Service Date	119.3	119.3	9.8	69.5
25th Anniversary of In Service Date	119.3	119.3	9.8	69.5

(1) Average monthly peak load for anniversary year, based on PLI of 0.78.

NETWORK REVENUE REQUIREMENTS AND LOAD FORECAST AT THE NEW OR MODIFIED CONNECTION FACILITIES

Annual Period Ending On:	New Load** - (MW)	Part of New Load Exceeding Normal Capacity of Existing Load Facilities [C]	Adjusted Load Forecast (MW) [D]	Network Revenue (k$) for True-Up, Based on [C] or [D], whichever is applicable
1st Anniversary of In Service Date	18.6	18.6	0.3	8.3
2nd Anniversary of In Service Date	24.8	24.8	0.4	11.0
3rd Anniversary of In Service Date	30.5	30.5	0.5	13.6
4th Anniversary of In Service Date	36.4	36.4	0.6	16.2
5th Anniversary of In Service Date	42.6	42.6	0.7	18.9
6th Anniversary of In Service Date	48.8	48.8	0.8	21.7
7th Anniversary of In Service Date	55.3	55.3	0.9	24.6
8th Anniversary of In Service Date	62.0	62.0	1.0	27.5
9th Anniversary of In Service Date	68.8	68.8	1.1	30.6
10th Anniversary of In Service Date	75.9	75.9	1.2	33.7
11th Anniversary of In Service Date	83.2	83.2	1.3	37.0
12th Anniversary of In Service Date	90.7	90.7	1.5	40.3
13th Anniversary of In Service Date	98.4	98.4	1.6	43.7
14th Anniversary of In Service Date	106.4	106.4	1.7	47.3
15th Anniversary of In Service Date	114.3	114.3	1.8	50.8
16th Anniversary of In Service Date	119.3	119.3	1.9	53.0
17th Anniversary of In Service Date	119.3	119.3	1.9	53.0
18th Anniversary of In Service Date	119.3	119.3	1.9	53.0
19th Anniversary of In Service Date	119.3	119.3	1.9	53.0
20th Anniversary of In Service Date	119.3	119.3	1.9	53.0
21st Anniversary of In Service Date	119.3	119.3	1.9	53.0
22nd Anniversary of In Service Date	119.3	119.3	1.9	53.0
23rd Anniversary of In Service Date	119.3	119.3	1.9	53.0
24th Anniversary of In Service Date	119.3	119.3	1.9	53.0
25th Anniversary of In Service Date	119.3	119.3	1.9	53.0

** New Load based on Customer's Load Forecast which includes Part of New Load Exceeding Normal Capacity of Existing Load Facilities. "Overload" derived in accordance with Section 6.7.9 of the Transmission System Code and the OEB-Approved Connection Procedures. Any Customer load below the Normal Capacity of the Existing Load Facilities transferred to the New or Modified Facilities will not be credited towards the Transformation Connection Revenue Requirements, Line Connection Revenue Requirements or the Network Connection Revenue Requirements. The discounted cash flow calculation for Network Revenue requirements will be based on Incremental Network Load which is New Load less the amount of load, if any, that has been by-passed by the Customer at any of Hydro One's connection facilities.

APPENDIX AK

APPENDIX 1 - HOBNI OVERHEAD ANALYSIS - 2006 to 2008

STAGE 1 - DATA NORMALIZATION & ALIGNMENT OF COST AND RECOVERY

		2006 Actuals	2006 Normalized	Increase / (Decrease) 06 to 07 Actuals**	Increase / (Decrease) 06 to 07 Normalized	2007 Actuals	2007 Normalized	Increase / (Decrease) 07 to 08 Actuals**	Increase / (Decrease) 07 to 08 Normalized	2008 Actuals	2008 Normalized	Notes
3. INVENTORY CONTROL												
Inventory Price Variance	9041	114,967.40	114,967.40	-120%	-120%	(22,668.38)	(22,668.38)	223%	223%	27,903.52	27,903.52	
Stores Expense	9045	954,157.83	1,049,098.83	2%	1%	968,972.30	1,063,913.30	24%	12%	1,196,685.04	1,196,685.04	1
Stores Operation Clearing	9040											
Smart Meter Inventory Issues (M780, M781, M782)		(3,609.00)	-	19943%	0%	(723,360.00)	-	5%	0%	(756,716.00)	-	2
Material Issues Except Smart Meters		(1,137,489.23)	(1,137,489.23)	-9%	-9%	(1,032,626.00)	(1,032,626.00)	23%	23%	(1,269,539.00)	(1,269,539.00)	
20% Recovery via 9083 for One-off MFA Purchases		(314,292.75)	(314,292.75)			(353,130.07)	(353,130.07)			(296,735.81)	(296,735.81)	3
Net Under / (Over) Inventory Recovery		**(386,265.75)**	**(287,715.75)**			**(1,162,812.15)**	**(344,511.15)**			**(1,098,402.25)**	**(341,686.25)**	

NOTE:

* The normalization analysis is only performed for GL accounts where overhead rate recovery is applied in order to determine if there are one-off incidents that increased / decreased the account balance. Accounts with > $300K for each of the 3 years and with > 10% variance between any 2 years are further discussed in the Notes.

1 In March 2008, a new junior buyer was hired. Gross pay in 2008 is $30.43, leading to increase in Store expense of $30.43 * 40 hrs/wk * 52 wks *150% top up = $94941. To normalize stores expenses, the junior buyer's salary is added to year 2006 and 2007 balances.

2 In late 2006, the OEB introduced the smart meter program, and aims to finish installing smart meters in each household by 2010. As a result, HOBNI purchased additional smart meter inventory and included a 17% top up on these items. Smart meters generally require minimal work from Purchase department because the contracts and orders are in place, and the smart meters require minimal storing work and material handling. Also the smart meter project will end in 2010 and thereafter will be handled as regular inventory. As a result, overheads recovered from smart meters are isolated for normalization for 2006-2008.

3 Non-inventory purchases are one-off purchases for specific reasons, e.g. an equipment is required and purchased by Engineering for a specific project. These items do not have part numbers and are considered as minor fixed assets (MFA). Currently a 20% recovery rate is applied to all such purchases. The cost of the MFA plus the 20% recovery is debited to an account in the 1900 series accounts, and the recovery is credited to account 9083.

STAGE 2 - RATE ADJUSTMENT BASED ON NORMALIZED DATA

	2006 Actuals	2006 Normalized	2007 Actuals	2007 Normalized	2008 Actuals	2008 Normalized	Averaged & Normalized Results
INVENTORY CONTROL							
Estimated Materials Issued to Word Order		6,691,113.12		6,074,270.59		7,467,876.47	
Amount of Minor Fixed Assets Purchased and Recovered via 9083		705,315.28		889,904.67		899,701.78	
Total		7,396,428.40		6,964,175.26		8,367,578.25	
Amount to Recover		1,164,066.23		1,041,244.92		1,224,588.56	
Amount Recovered from Vehicles		34,593.82		35,230.95		43,351.94	
Remaining Amounts to Recover		1,129,472.41		1,006,013.97		1,181,236.62	
Adjusted Recovery Rate		15%		14%		14%	15%

HYDRO ONE BRAMPTON INC.
OVERHEAD COMPARISONS - NO SMOOTHING

	ACCT. #	2003	2004	2005	2006	2007	2008	2009
Inventory Price Variance	9041	(23,813.12)	12,032.23	6,059.89	114,967.40	(22,668.38)	27,903.52	(16,519.69)
Stores Expense	9045	687,319.14	743,426.77	845,869.83	954,157.83	968,972.30	1,196,685.04	1,297,318.98
Stores Operation Clearing	9040	(981,820.34)	(1,060,688.60)	(1,208,238.21)	(1,141,098.23)	(1,755,985.59)	(2,026,255.23)	(2,072,531.55)
SUB TOTAL		(318,314.32)	(305,229.60)	(356,308.49)	(71,973.00)	(809,681.67)	(801,666.67)	(791,732.26)

APPENDIX AL

OVERHEAD ANALYSIS
PROCESS DOCUMENTATION

Material Issues Recovery

This document focuses on the overhead rate analysis for the Inventory Control department. The purpose of this analysis is to:

(a) Determine if current overhead recovery rates accurately recover overhead departments' expenses. If not, adjust the rates accordingly for effective recovery.
(b) Based on the Cradle to Grave Report and improved timesheet records, quantify the impact of the new timesheet system on overhead recovery rates.

The analysis is based on GL data obtained from the AS400 mainframe computer. The name of each data file is noted in the comment boxes of file "Overhead Summary 2006-2008 – Final".

Work steps and analysis:

Step 1: Data Normalization & Alignment of Cost and Recovery (please first refer to the notes in the file "Overhead Summary 2006-2008 – Final" for detailed analysis performed for data normalization) – Obtain data from AS400 for a 3-year analysis (2006-2008). Rationalize the relationship between existing overhead rates and overhead costs accounts. Normalize the data and determine which department experiences over / under recovery base on existing overhead rates.

Analysis for Step 1:

Material Issue Overhead

Account 9041 includes the differences between purchase orders and actual invoices that cannot be allocated due to rounding. The difference often arises due to freight charges. There is no associated recovery account as the variances are expected to be allocated to inventory. In variances noted in each of 2006 to 2008 are immaterial to HOBNI.

Account 9045 includes expenses associated with operating the Purchasing and Stores departments, including labour, allocation of building and service costs, depreciation and travel.

In general the Inventory Control department expenses are recovered through

- A markup of 17% on materials issued
- 20% recovery on one-off minor fixed asset purchases (MFA), which is captured in account 9083

To normalize the data, only on-going materials issues are considered. Materials issued related to smart meter are stripped as they relate to a specific project of limited duration and should have no impact on on-going overhead rates.

Step 2: For departments with significant over / under recoveries, adjust the overhead rates base on normalized data.

Analysis for Step 2:

In summary, after performing step 1, over/(under) recoveries by year were determined:

2006 -	287,716
2007 -	344,511
2008 -	341,686

The recovery rates was adjusted based on total normalized costs to recovery divided by the basis of recovery. Total normalized costs for each material issues were calculated and shown on the "Material Issue Overhead Rate Calculation 2009" file. The basis of recovery for the Purchasing Department is materials issued.

5. Conclusion:

It was determined that the material issues rate of 20% for MFA purchases and 17% for all inventory issues was consistently over-recovering the expenses incurred by the Purchasing and Stores departments. Calculations performed indicated that the rate would need to be reduced to 15% for both MFA and inventory material issues in order to avoid over or under recovery of costs.

APPENDIX AM

Hydro One Brampton Networks Inc.

2005-2007 Vehicle Rates Review

1. Rolling Stock Operation Allocation of Costs

a) Accounting Procedures Handbook Guidance

In Article 340 of the Accounting Procedures Handbook, the OEB addresses Rolling Stock Operation as follows:

A rolling stock operation clearing account may be used to accumulate the costs associated with maintaining automobiles, trucks and equipment, trailers and the like. Labour costs and the associated payroll burden of staff directly involved in rolling stock maintenance, such as mechanics, may be included in this account.

Common rolling stock operation costs may include such costs as rolling stock operating and depreciation expense, including fuel, lubricants, repairs and parts, license fees,insurance and all other items of expense necessary to keep the rolling stock in service. A rolling stock operation account may also include the costs associated with the operation and maintenance of garages and garage equipment as well as related office clerical and/or computer costs that relate directly to rolling stock operation.

The method of allocating rolling stock operation overhead may be based on a per kilometre rate or per hour of use or available for use basis depending on the various types of rolling stock.

Any residual balance remaining after regular distribution shall be cleared to the applicable plant and operating accounts by apportioning on a basis which will distribute the costs equitably. If the dollar amount of the unallocated balance is material, the original basis of allocation and related calculations should be checked to confirm or adjust the basis of allocation and related calculations.

b) HOBNI Methodology

At HOBNI, vehicles are classified according to groups and each group is assigned an hourly rate. The following rates are in effect as of October 2008.

Rate per hour	Vehicle Type
$6	Trailers (Box covered, reel/cable, cargo, dump)
8	Cars and Vans
10	Pole trailer
12	Pick-up Trucks and SUVs
15	Forklifts
18	Box trucks
20	Compressor, Overhead Tensioners, Transformers
25	Stake Trucks, Substation Cube Trucks
35	Tractor for Pole Trailer
40	Aerials Single Bucket
45	Single Material Handler, Digger Derricks, Hiab
55	Aerials Double Bucket
60	Underground Cable Puller

Personnel enter truck timesheets in AS400 menu xxx based on the reported usage to a given work order or job. When the payroll officer posts the weekly payroll, truck time is charged to a job. For example, if a truck with a $12/hour rate was charged out for 2 hours, the entry would be

Dr. Capital/OM&A work order	$24	
Cr. 9070-0 Truck operation clearing		$24

Any remaining balance, whether it be an over- or under-recovery of costs, is allocated on the basis of payroll dollars on a monthly basis as part of the variable overhead allocation.

c) Other Industry Practices

In all cases discussed where vehicle rates were used to recover costs, the cost driver chosen has been hours, as opposed to km, as it was the general consensus that motor running hours are the better cost driver than number of kilometers driven.

Oshawa PUC Networks Inc. Hydro uses a simplified vehicle rate structure with two rates only, whereupon large equipment has a rate of $35/hour, while lighter equipment such as trucks has a rate of $10/hour.

Haldimand County Hydro uses a simplified vehicle rate structure as well with two rates only, where large equipment would have a rate of $39/hour, while pickup trucks have a rate of $18/hour. They do not charge for trailers separately, as their costs are part of the large equipment rates.

From various other utilities companies, larger equipment rates ranged as high as $40-45/hour.

Guelph Hydro Electric Systems Inc., on the other hand, does not use vehicle rates, but uses an additional payroll burden of 65% and 25% on capital versus maintenance projects to recover those costs.

In all cases discussed, the over- or under-recovery of costs is allocated based on truck hours, the cost driver for rolling stock operations.

2. Sources of Information

a) Cost Breakdown with Fuel

Hydro One Brampton Networks Inc. maintains a fleet system where costs are allocated to different vehicles. The report "FDMOPFK" Cost Breakdown with Fuel can be obtained which breaks down the costs per vehicle:

Internal labour: Costs associated with internal staff doing maintenance work (not including the 50% overhead used for AS/400 purposes)

Internal Material: Costs for inventory material.

External Labour: Costs for contracted maintenance to outside suppliers

External Material: Costs for material purchased from outside suppliers

Fuel Cost: Based on volume filled up, times the fleet system cost of fuel.

b) AS/400 General Ledger Information

- All information from the fleet system was compared and agreed to information in our General Ledger system
- G/L 9075 captures all of the costs of maintaining fleet vehicles and equipment, including depreciation and leasing.
- G/L 9070 captures all of the fleet recoveries due to vehicles being charged out at a certain rate deemed sufficient to recover the cost of operation and depreciation of the vehicle.

c) Truck depreciation ledger

- This information was summarized by vehicle and was agreed to the depreciation as per the AS/400.

3. Outline of methodology to arrive at Calculated Overhead costs

The fleet system is totally separate from AS/400. AS/400 work order level costs were compared to the information in the fleet system as follows.

1) Labour: Fleet system did not include the 50% labour overhead rate, therefore Internal labour was first multiplied by 160%. This value was compared to the sum of the balances in work orders
K190-0 Fleet Dept. – Labour
K191-0 Retrieve Parts – Labour
K192-0 Cleaning Shop – Labour
Q144-2 Sandalwood Pkwy Costs for Committee

Any balance remaining was allocated by group of vehicles based on their percentage of the total internal labour.
The balances that were allocated are as follows:

Year	Total labour	Allocated labour	%
2007	$460,345	$64,093	14%
2006	$447,947	$30,232	7%
2005	$449,152	$ 2,919	1%

Remaining balances are due to more overtime hours in 2007 versus 2005.

2) Maintenance Costs: Fleet information External Labour, Internal Material, External Material and Fuel were added and called maintenance costs. This total was compared to the sum in the balances in work orders

K190-1 Fleet Dept. – Materials
K190-2 Fleet Dept. – Contracts
K190-0 Fleet Dept. – Other
K191-2 GPS Pilot
N769-0 Shop Operating Expense
N770-0 Shop Operating Supplies
9075-0 Fuel Inventory Adjustment

Any balance remaining was allocated by group of vehicles based on their percentage of the total maintenance costs.

Year	Total maintenance	Allocated maintenance	%
2007	$766,612	$ 92,808	12%
2006	$832,902	$149,968	18%
2005	$662,824	$ 20,462	3%

Remaining balances are due to no PST being entered in the fleet system, costs for items not part of fleet vehicles (eg. Compressors, generators, Geni Man Lift, pressure washer).

3) Depreciation: The vehicle subledger was agreed to K191-1 Vehicle Depreciation for years 2005 and 2006, and to the vehicle-specific work orders in 2007.

Year	Depreciation
2007	$514,897
2006	$613,827
2005	$533,868

Depreciation decreased in 2007, as salvage values were estimated and assigned to vehicles with a Net Book Value greater than zero.

4) Overhead: The total of overhead from
K191-3 Fleet Overhead Monthly
K191-9 Fleet Allocated Bldg Costs Variable
was allocated to each vehicle equally.

Year	Overhead
2007	$378,982
2006	$332,828
2005	$364,900

5) Downtime: HOBNI started recording downtime in August 2006. When vehicles are broken down and awaiting to be put back in-service, a truck sheet is filled in and the hours booked to K194-2 Vehicle Down-time.

Year	Hrs Downtime	Downtime
2007	17,794	$394,450
2006	5,825	$136,148
2005		$ -

If the hours of downtime in 2006 were prorated for 12 months, there would have been 13,980 hours or $326,755 of downtime.

6) Rentals: A&W High Voltage rentals of vehicles are coded to work order K190-3 Fleet Dept. – Rentals. These costs are to rent Aerials Double Bucket and are assigned to this vehicle group.

Year	Rentals
2007	$86,101
2006	$69,434
2005	$ 6,408

4. Analysis of Net Over/(Under) Recovery of Costs (from AS/400)

Component	2005		2006		2007	
Labour	449,152	*22%*	447,947	*18%*	$460,345	*18%*
Maintenance Costs	662,824	*33%*	832,902	*34%*	766,612	*29%*
Depreciation	533,868	*27%*	613,827	*25%*	514,897	*20%*
Overhead	352,532	*18%*	332,828	*14%*	378,982	*15%*
Downtime			136,148	*6%*	394,450	*15%*
Rentals	6,408		69,434	*3%*	86,101	*3%*
TOTAL COSTS	**2,004,783**		**2,433,085**		**2,601,387**	
RECOVERIES	**(2,187,390)**		**(2,438,673)**		**(2,617,882)**	
Under/(Over) Recoveries	**(182,607)**		**(5,588)**		**(16,495)**	

5. Analysis of 3-year historical information

Note: The appendices can be found at: R:\Accounting Files\Overhead Comparisons\2007 Truck Overhead analysis (Ctrl-Click to access).

a) Number of Vehicles and Hours by Group – Appendix A

The total number of vehicles by group has remained fairly constant in 2005, 2006 and 2007 at 111, 105 and 111 (See Appendix A Table 1).

From Appendix A Table 3, the groups of vehicles being used the most as a function of total hours are:

Group	Description	Percentage
VAN	Vans	18%
TRK	Stake Trucks	15%
PUT	Pick-up Trucks	12%
SMH	Single Material Handler	12%
DBL	Aerials Double Bucket	12%

From Appendix A, Table 4, the groups of vehicles being used the most as a function of days per vehicle are:

Group	Description	Days used
SMH	Single Material Handler	304
CUB	Substation Cube Trucks	186
PUT	Pick-up Trucks	179
VAN	Vans	161
RBD	Digger Derricks	137

b) Operating Costs by Group – Appendix B

From Appendix B, Table 1, the group of vehicles where we spend the most internal labour per vehicle are:

Internal Labour

Group	Description	Per vehicle
SMH	Single Material Handler	$16,029
RBD	Digger Derricks	$10,976
DBL	Aerials Double Bucket	$ 9,619
TEN	Overhead Tensioners	$ 9,403
SIN	Aerials Single Bucket	$ 9,191

From Appendix B, Table 2, the group of vehicles where we spend the most in maintenance costs (external labour, internal supplies and external supplies) are:

Maintenance Costs

Group	Description	Per vehicle
SMH	Single Material Handler	$36,878
DBL	Aerials Double Bucket	$19,452
RBD	Digger Derricks	$18,688
SIN	Aerials Single Bucket	$17,011
HIA	Hiab	$14,617

From Appendix B, Table 3, the group of vehicles with the most depreciation expense are:

Depreciation

Group	Description	Per vehicle
SMH	Single Material Handler	$36,878
DBL	Aerials Double Bucket	$19,452
RBD	Digger Derricks	$18,688
SIN	Aerials Single Bucket	$17,011
HIA	Hiab	$14,617

Overall, the biggest component of Operating Costs is Internal Labour, followed by maintenance and depreciation. Overhead is the smallest of all of the components in most cases (see Appendix B, Table 5 and Graph).

c) <u>Recoveries by Vehicle Group – Appendix C</u>

By comparing 2005 to 2007 recoveries (See Appendix C, Table 1), it seems clear that

1) Cars, SUV and Vans are consistently under-recovered
2) Trailer operating costs are consistently under-recovered
3) Stake trucks, Substation cube trucks, Aerials SB, Single material handler and Digger Derricks are consistently over-recovered.

Thus, there seems to be a situation where the charge-out rates being used for heavier equipment is funding the lighter vehicles and trailers.

d) <u>Calculated Vehicle Rates Based on Costs – Appendix D</u>

For all three years, a vehicle rate was calculated by dividing the total operating costs by vehicle group and dividing by the total number of hours utilized. The same conclusions as previously discussed were reached (See Appendix D, Table 1).

The calculated vehicle rate for trailers seem very high and unreasonable because of the fact that trailers are older and are utilized a lot less than the other vehicles.

e) Recoveries using Average and Suggested Rates

Appendix B Table 1 details the actual vehicle rate, the calculated vehicle rate, suggested rate 1 and suggested rate 2.

Suggested rate 1 was developed from the average calculated rates.

Suggested rate 2 was developed using as a premise that we can't charge $400/hr for trailers, thereby we do have to increase the rates of other vehicles to cover this under-recovery.

Group	Description	Actual Rate	Avg Rate	Suggested Rate 1	Suggested Rate 2
CAR	Cars	8	18	15	18
SUV	SUV	12	32	20	20
VAN	Vans	8	12	12	12
PUT	P/U Trucks	12	12	12	12
TRK	Stake Trucks	25	18	20	20
BOX	Box trucks	18	17	15	15
CUB	substation cube trucks	25	13	12	12
SIN	Aerials single bucket	40	36	35	40
DBL	Aerials double bucket	55	54	55	60
SMH	Single Material handler	45	37	35	45
RBD	Digger Derricks	45	46	45	45
HIA	Hiab	45	45	45	45
TOW	Forklift	15	64	60	60
BCT	Box covered	6	101	100	10
CAB	Reel/cable	6	44	40	6
CCW	Compressor	20	110	100	20
CGO	Cargo	6	17	15	10
DUM	Dump	6	24	15	6
POL	Pole	10	58	40	10
TRT	Tractor for Pole Trailer		2,202		20
U/G	Underground cable puller	60	396	400	60
TEN	Overhead Tensioners	20	99	100	20
	Transformers	50	71	50	20

**2009 rates

If one uses the 3-year average of the calculated vehicle rates, and uses this as a basis for the recoveries, the net over-recovery would be $160,000. The rates were adjusted in two other suggested rates as follows:

Rates	Net recoveries over 3 years
Actual	($200,600)
Average rate	($160,000)
Suggested rate 1	($ 50,000)