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Susan Frank
Vice President and Chief Regulatory Officer
Regulatory Affairs

BY COURIER

August 29, 2012

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

Dear Ms. Walli:

EB-2012-0136 – Hydro One Networks' 2013 Distribution IRM Rate Application – Application and Evidence Update Filing

I am attaching ten (10) paper copies of updates and additional evidence with respect to Hydro One Networks' Application and Prefiled Evidence that was filed with the Board on June 15, 2012.

A detailed list of the updates and additional evidence is provided in the attached document.

Please note that the updates provided are inclusive of pagination revisions. As such, for ease of reference, content changes to the prefiled evidence are indicated by a solid bar in the far right margin

An electronic copy of the attached updates and additional evidence has been filed using the Board's Regulatory Electronic Submission System.

Sincerely,

ORIGINAL SIGNED BY SUSAN FRANK

Susan Frank

Attach.

List of all new evidence and updates:

Exhibit A, Tab 1, Schedule 1	Update page 1
Exhibit A, Tab 2, Schedule 1	Update pages 2-3
Exhibit A, Tab 3, Schedule 1	Update pages 1-2; 4-5
Exhibit A, Tab 6, Schedule 1	Update page 1 and new Attachments 3 to 6
Exhibit A, Tab 8, Schedule 1	New Attachments 1 to 2
Exhibit B, Tab 1, Schedule 1	Update page 7
Exhibit B, Tab 1, Schedule 2	Update page 1
Exhibit B, Tab 3, Schedule 1	Update pages 5, 13, 18, 19
Exhibit C1, Tab 1, Schedule 1	Update pages 4-5
Exhibit D1, Tab 1, Schedule 1	Update Attachment 1, pages 9, 10, 49 new Sign-off document
Exhibit E1, Tab 2, Schedule 1	Update pages 1-2 and Appendix A
Exhibit E2, Tab 2, Schedule 2	Update rate schedules
Exhibit E2, Tab 2, Schedule 3	Update page 1

EXHIBIT LIST

B				**Incremental Capital Module**
	1	1		Proposed Incremental Capital Module
		2		Calculation of Incremental Capital Module Revenue Requirement
	2	1		Escalated Issue Capital – Capital Contributions
		2		Escalated Issue Capital – Distribution and Regulating Stations
		3		Escalated Issue Capital – Wood Pole Replacement
	3	1		Non-Typical Capital – Customer Information System (CIS)
			Att. 1	Green Energy Benefit Implementation Assessment
			Att. 2	Hydro One Board Approval Document – Cornerstone Phase 4
C				**Smart Grid and RTSR**
	1	1		Smart Grid
	2	1		Retail Transmission Service Rates
D				**Density Study**
	1	1		Density Study Proposal
			Att. 1	Customer Density and Distribution Service Costs
			Att. 2	Density Study Adjustment of 2010 Cost Allocation Model Results
			Att. 3	Density Study Adjustment to Rates
E1				**Rates**
	1	1		Completion of Previously Approved Rate Harmonization
	2	1		Rate Rider Calculations
			App. A	2012 IRM 3 Tax Savings Workform
			Att. 1	Calculation of ICM Variable Rate Riders by Rate Class
			Att. 2	Calculation of Smart Grid Variable Rate Riders by Rate

				Class
			Att. 3	Calculation of Shared Tax Savings Variable Rate Riders by Rate Class
			Att. 4	Continuity Schedules- Group 1 Accounts
	3	1		Customer Bill Impact Summary
E2				**Supporting Schedules**
	1	1		2013 OEB 3GIRM Filing Module Output Sheets
	2	1		Current Rate Schedules
		2		Proposed Rate Schedules
		3		Proposed Rate Schedules based on Density Study Adjusted Rates
	3	1		Customer Impacts
		2		Customer Impacts based on Density Study Proposed Rates

ONTARIO ENERGY BOARD

IN THE MATTER OF *the Ontario Energy Board Act, 1998*;

AND IN THE MATTER OF an Application by Hydro One Networks Inc. for an Order or Orders approving rates for the distribution of electricity.

APPLICATION

1. The Applicant is Hydro One Networks Inc. (Hydro One Networks), a subsidiary of Hydro One Inc. Hydro One Networks is an Ontario corporation with its head office at Toronto. The Applicant carries on the business, among other things, of owning and operating distribution facilities in Ontario. The distribution business of Hydro One Networks will be referred to as "Hydro One Distribution".

2. Hydro One Networks is applying to the Ontario Energy Board (the "Board"), pursuant to Section 78 of the *Ontario Energy Board Act, 1998*, for an Order or Orders approving the customer rates for the distribution of electricity, to be effective on January 1, 2013.

3. The scope of this Application includes:

    - The review of Distribution rates effective January 1, 2013 based on 2011 rates adjusted by:

        - 0.88% by application of the Board's IRM Price Cap Index Adjustment formula;

- The establishment of a rate rider to recover 2013 incremental in-service capital of approximately $645 million per Hydro One's proposed adjustments to the Board's Incremental Capital Module ("ICM") as outlined in Hydro One's submission in the Renewed Regulatory Framework proceeding (EB-2010-0377, EB-2011-0043 and EB-2011-0004) filed with the Board on April 20, 2012;

- The disposition of the Group 1 Deferral and Variance accounts balance of $(37.5) million as at December 31, 2011 and the determination of a rate rider to refund those balances over two years as outlined in the Report of the Board on Electricity Distributor's Deferral and Variance Account Review Initiative, EB – 2008-0046 dated July 31, 2009;

- The establishment of a rate rider associated with the 50%/50% sharing of the impact of decrease in income tax rate per the Supplemental Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors (EB-2007-0673) – September 17, 2008; also, pursuant to section 2.5 (Tax Changes) of Chapter 3 of the Filing Requirements for Transmission and Distribution Applications dated June 28, 2012;

- The establishment of a Smart Grid rate adder to recover Smart Grid OM&A spending of $19.8 million in 2013; and

- Approval to implement the final step of rate harmonization approved under EB-2007-0681.

- An adjustment to the retail transmission service rates as provided in the Board's Guideline (G-2008-0001) on Retail Transmission Service Rates – October 22, 2008 (Revision 4.0 June 28, 2012) to reflect the Board approved Uniform Transmission Rates effective January 1, 2012; and

- Approval to implement the results of the Density Study the Board directed Hydro One to undertake as part of its EB-2009-0096 Decision.

4. The written evidence filed with the Board may be amended, if necessary, at any time prior to the Board's final decision on the Application. Further, the Applicant may seek meetings with Board staff in an attempt to identify and reach agreements to settle issues arising out of this Application.

5. The persons affected by this Application are the ratepayers of Hydro One Networks' Distribution business. It is impractical to set out their names and addresses because they are too numerous.

6. Hydro One Networks requests that a copy of all documents filed with the Board by each party to this Application be served on the Applicant and the Applicant's counsel as follows:

   a) The Applicant:

Mr. Pasquale Catalano
Regulatory Coordinator
Hydro One Networks Inc.

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483 Bay Street
Toronto, ON M5G 2P5

Mailing Address: 8th Floor, South Tower
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Telephone: (416) 345-5405
Fax: (416) 345-5866
Electronic access: regulatory@HydroOne.com

b) The Applicant's counsel:

Mr. D.H. Rogers, Q.C.
Rogers Partners LLP

Address for personal service: 100 Wellington Street West
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Toronto, ON M5K 1J5

Mailing Address: 100 Wellington Street West
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Ms. Anita Varjacic
Rogers Partners LLP

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Fax: (416) 594-9100
Electronic access: anita.varjacic@rogerspartners.com

DATED at Toronto, Ontario, this 25th day of May 2012.

HYDRO ONE NETWORKS INC.
By its counsel,

ORIGINAL SIGNED BY DON H. ROGERS
Don H. Rogers

SUMMARY OF APPLICATION

Hydro One Networks ("Hydro One" or "Hydro One Distribution") is applying for an adjustments to rates and charges in accordance with directions provided by the Board pursuant to the 3rd Generation Incentive Rate Mechanism ("IRM3") effective on January 1, 2013 under the assigned Docket Number EB-2012-0136. Hydro One Distribution's rates were last rebased for the 2011 test year as per the Board's Decision in EB-2009-0096. This summary provides a brief description of the approvals being sought through this Application and a summary of reasons for the requested adjustments in customer rates.

1.0 SCOPE OF APPLICATION

The scope of this Application includes:

- the review of Hydro One Distribution's evidence in support of the revised Distribution rates effective January 1, 2013;
- an adjustment to the Retail Transmission Service Rates ("RTSR") as provided in the Board's Guideline (G-2008-0001) on Retail Transmission Service Rates – October 22, 2008 (Revision 4.0 June 28, 2012) to reflect the Board approved Uniform Transmission Rates effective January 1, 2012; and
- the request for approval to implement the results of the Density Study the Board directed Hydro One to undertake as part of its EB-2009-0096 Decision.

This submission reflects Hydro One Distribution's plan to invest in its network assets to meet objectives regarding public and employee safety; regulatory and legislative compliance; maintenance of system security and reliability; system growth requirements and investments required to facilitate renewable generation connections.

This Application by Hydro One Distribution is substantially consistent with the requirements of the 2006 Electricity Distribution Rate Handbook ("the Handbook") issued by the Board on May 11, 2005 and with the Filing Requirements for Transmission and Distribution Applications (the "Filing Requirements") issued by the Board on November 14, 2006 and updated Chapter 3 issued by the Board on June 28, 2012.

Hydro One is requesting the use of the 2013 Board Approved Cost of Capital parameters in the calculation of revenue requirement associated with the Incremental Capital Module. For rates effective January 1, 2013, the Board would determine the return on equity ("ROE") and other Cost of Capital parameters for Hydro One Distribution based on the September 2012 Consensus Forecasts and Bank of Canada data which would be available in October 2012. Further discussion on Cost of Capital can be found in Exhibit B, Tab 1, Schedule 2.

Hydro One also undertook a stakeholder consultation process to increase understanding of the issues in this Application and to provide a forum for early identification of stakeholder concerns, as documented in Exhibit A, Tab 4, Schedule 1.

2.0 APPROVALS REQUESTED

2.1 Distribution Rates

The Company is seeking approvals for Distribution rates effective January 1, 2013 based on Board approved 2011 rates adjusted by:

1. The OEB's 2012 IRM3 Rate Generator Model calculated a Price Cap Index increase of 0.88% for Hydro One Distribution based on a Price Escalator ("GDP-IPI") of 2.0%, minus a Productivity Factor of 0.72% minus a Stretch Factor of 0.40%. The price escalator (or inflation index) of 2%, for the 3rd Generation Incentive Regulation

mechanisms for adjusting electricity distribution rates effective May 1, 2012, was announced by the Board on March 13, 2012. Hydro One understands that the Price Escalator will be adjusted for those distributors whose rate year has been aligned with their fiscal year. Similarly, Hydro One recognizes that the Stretch Factor of 0.40% represents the 2011 amount as determined in the report “Third Generation Incentive Regulation Stretch Factor Updates for 2011 (EB-2009-0392)” issued by the OEB. Hydro One expects that the OEB will update each distributor’s 2013 IRM3 Rate Generator Model and therefore the distributor specific Price Cap Index for the 2013 stretch factor. It is expected that the information to update the stretch factors will be available before the implementation date of the 2013 Tariff of Rates and Charges;

2. The establishment of a rate rider to recover 2013 incremental in-service capital of approximately $645 million per Hydro One’s proposed adjustments to the Board’s Incremental Capital Module (“ICM”) consistent with Hydro One’s submission in the Renewed Regulatory Framework proceeding (EB-2010-0377, EB-2011-0043 and EB-2011-0004) filed with the Board on April 20, 2012. The detailed description on the Incremental Capital Module can be found in Exhibit B of this application and the calculations of the revenue requirement for the requested ICM recovery can be found in Exhibit B, Tab 1, Schedule 2. Hydro One Distribution proposes to recover this amount by means of a variable rate rider, as outlined in Exhibit E1, Tab 2, Schedule 1, which will remain in effect until Hydro One Distribution’s next cost of service application;

3. The establishment of a Smart Grid rate adder to recover Smart Grid OM&A spending of $19.8 million in 2013 as discussed in Exhibit C1, Tab 1, Schedule 1. Hydro One Distribution proposes to recover this amount by means of a variable rate rider which will remain in effect until Hydro One Distribution’s next cost of service application. The calculation of Smart Grid Rate Riders by rate class can be found in Exhibit E1, Tab 2, Schedule 1;

4. The establishment of a rate rider associated with the 50%/50% sharing of $1.1 million as a result of the decrease in income tax rate from 28.25% to 26.50%, in accordance with the Board's requirement set out in the Supplemental Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors (EB-2007-0673) dated September 17, 2008; also, pursuant to section 2.5 (Tax Changes) of Chapter 3 of the Filing Requirements for Transmission and Distribution Applications dated June 28, 2012. The calculation of Shared Tax Savings Rate Riders by rate class can be found in Exhibit E1, Tab 2, Schedule 1[1];

5. The disposition of the Group 1 Deferral and Variance audited accounts balance of $(37.5) million as at December 31, 2011. This amount results in a total credit claim of $0.00104 per kWh, which exceeds the disposition threshold established by the Board in the Report of the Board on Electricity Distributor's Deferral and Variance Account Review Initiative, EB-2008-0046 dated July 31, 2009. Hydro One Distribution is proposing to dispose this credit amount over a two-year period in order to mitigate rate volatility. Details on Group 1 Deferral and Variance accounts disposition can be found in Exhibit E, Tab 2, Schedule 1 and the continuity schedules of these accounts can be found in Exhibit E, Tab 2, Schedule 1, Attachment 4; and

6. Hydro One Distribution is not applying for a Z-factor Claim in this application, however, Hydro One is undertaking a pension valuation and may consider applying for a Z-factor Claim in the future, depending on the results of the valuation.

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[1] The original tax savings amount of ($1.7M) used in the IRM3 Model will not be updated at this time, however, the proposed tax savings amount of ($1.1M) will be reflected in the final rate order.

2.2 Other Approvals

1. Hydro One also requests the Board approve the implementation of the final step of rate harmonization approved under EB-2007-0681. Details can be found in Exhibit E1, Tab 1, Schedule 1 of this application;

2. Hydro One is also making an adjustment to the RTSR as provided in the Board's Guideline (G-2008-0001) on Retail Transmission Service Rates – October 22, 2008 (Revision 4.0 June 28, 2012) to reflect the Board approved Uniform Transmission Rates effective January 1, 2012. The proposed RTSR charges for each rate class can be found in Exhibit C, Tab 2, Schedule 1; and

3. Hydro One seeks the Board's approval to implement the results of the Density Study the Board directed Hydro One to undertake as part of its EB-2009-0096 Decision. The results of the Density Study are discussed in detail in Exhibit D, Tab 1, Schedule 1 and attachments.

3.0 CONCLUSION

If the proposed adjustments are approved by the Board, distribution rates for a residential customer with an annual consumption of 800 kWh will rise by approximately 2.9% or 1.0% on a total bill basis in 2013. Including previously Board approved RTSR adjustments for 2011 and 2012, the total bill impact would be approximately 2.1%.

RECENT RATING AGENCY REPORTS

Included in this Exhibit are copies of the most recent rating agency reports performed by Moody's Investor Service and Standard & Poor's.

Attachment 1: Standard & Poor's, Research Update dated: April 25, 2012
Attachment 2: Moody's Investor Service, Global Credit Research dated: April 27, 2012
Attachment 3: DBRS Rating Report dated: June 20, 2012
Attachment 4: Standard & Poor's Report: dated June 27, 2012
Attachment 5: DBRS Rating Report dated: August 22, 2012
Attachment 6: Moody's Investor Service, Global Credit Research dated: August 23, 2012

Insight beyond the rating.

Rating Report

Report Date:
June 20, 2012

Previous Report:
February 29, 2012

Hydro One Inc.

Analysts
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The Company
Hydro One Inc. is the largest regulated electric transmission and distribution utility in Ontario, serving more than 97% of the province's transmission throughput. The Company also owns a fibre-optic network across most of Ontario. Hydro One is wholly owned by the Province of Ontario (rated AA (low)).

Commercial Paper
Authorized Limit of $1.0 Billion

Recent Actions
February 29, 2012
Confirmed

January 11, 2012
$300 Million Issue Rated A (high)

Rating

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

Rating Rationale

The credit quality of Hydro One Inc. (Hydro One or the Company) is based on the Company's low-risk regulated transmission and distribution businesses, a supportive regulatory environment in Ontario and the Company's strong financial profile. Hydro One's regulated transmission and distribution businesses in Ontario account for virtually 100% of total earnings.

Regulation in Ontario has remained supportive for Hydro One. The Ontario Energy Board (OEB) is expected to continue to allow the Company to maintain adequate coverage, cash flow and leverage ratios due to the government's commitment to address Hydro One's aging infrastructure while meeting the continued growth of electricity consumption and renewable energy developments in the province without compromising reliability. The confirmation assumes that Hydro One's transmission and distribution revenue base will continue to grow favourably to support a high level of capital expenditure (capex), which is expected to continue to far exceed depreciation. Project execution risk is expected to be manageable; the Company is experienced in managing projects and is focused on mitigating the risk of cost overruns. On June 19, 2012, Hydro One's Bruce to Milton Transmission line came in-service, which transports 3,000 megawatts (MW) of power from nuclear and wind facilities.

Hydro One's credit metrics have remained relatively stable over the past four years. The Company generated a cash flow deficit of approximately $225 million for the three months ended March 31, 2012 (Q1 2012), which is debt-financed. The deficit was largely driven by ongoing high capex attributable to the Advanced Distribution System project and infrastructure sustainability spending. As a result of the ongoing high investment commitment ($1.8 billion per annum for the 2012–2014 period) and resulting incremental debt issuances, DBRS expects a temporary modest weakening of Hydro One's key credit metrics over the next several years. However, these ratios are expected to gradually recover when substantial capex plans are completed, and should remain well within the A (high) rating category.

Rating Considerations

Strengths
(1) Low business risk
(2) Strong financial profile
(3) Strong and extensive franchise area

Challenges
(1) High level of planned capital expenditure
(2) Project construction risk
(3) Significant external financing requirements

Financial Information

	USGAAP	USGAAP	USGAAP	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP
Hydro One	**3 mos. Mar. 31**		**12 mos. Mar. 31**	**For the year ended December 31**				
(CA$ millions where applicable)	**2012**	**2011**	**2012**	**2011**	**2010**	**2009**	**2008**	**2007**
EBIT gross interest coverage (times)	3.13	3.28	2.72	2.75	2.42	2.23	2.71	2.88
Total debt in capital structure	56.6%	56.1%	56.6%	55.5%	56.5%	56.2%	54.5%	53.5%
Cash flow/Total debt	16.9%	18.5%	14.4%	15.1%	13.8%	13.4%	15.1%	17.9%
Cash flow/Capital expenditure (times)	1.19	1.31	0.86	0.88	0.69	0.63	0.78	0.92
Net income before extraordinary items	208	209	632	632	579	470	498	399
Cash flow from operations	352	362	1,201	1,211	1,070	930	927	1,006

Rating Considerations

Strengths

(1) **Low business risk.** Almost all of the Company's EBIT is contributed by its low-risk regulated distribution and transmission business, which operates under a reasonable regulatory framework.

(2) **Strong financial profile.** The Company continues to maintain strong and stable credit metrics and a healthy balance sheet (debt-to-capital ratio at 56.6%, EBIT interest coverage at 2.72 times and cash flow-to-debt at 14.4%, for the twelve months ended March 31, 2012).

(3) **Strong and extensive franchise area.** Hydro One owns the largest transmission and distribution businesses in Ontario. The Company serves more than 97% of the province's transmission throughput. The distribution component of the Company spans approximately 75% of the province, serving 1.4 million customers (rural and urban) as well as 435 large-user customers.

Challenges

(1) **High level of planned capital expenditure.** Hydro One is currently in the midst of an aggressive build-out program that will continue over the next several years. Capex is expected to be approximately $5.5 billion over the next three years. Therefore, DBRS expects that annual capex could exceed operating cash flows by approximately $700 million to $800 million per year over that time frame. These sizable free cash flow deficits, combined with lengthy construction times, will continue to put temporary pressure on the balance sheet and coverage ratios during the build-out.

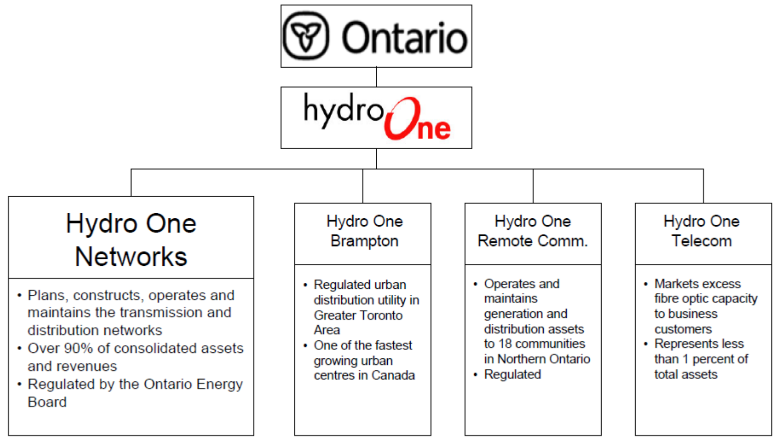
(2) **Project construction risk.** The size and magnitude of Hydro One's upcoming designated projects, combined with the continued increases in material and labour costs and the significant number of interveners involved, could potentially expose Hydro One to rising project costs beyond the amounts forecast 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.

(3) **Significant external funding requirements.** Significant external funding is required to finance the potentially sizable free cash flow deficits expected over the near to medium term. Maintaining adequate access to the public debt markets (term and commercial paper) is critical to the Company during this key build-out phase.

Major Projects (Potential and Under Construction)

- **West of London Transmission Lines.** Projects with the aim of adding between 500 MW and 1,000 MW to the grid. These projects are in the early stages with an expected completion date in 2017, contingent on the necessary regulatory approvals. Estimated costs range from $300 million to $450 million.
- **East-West Tie Project.** Through the East-West Tie LP (an equal partnership between three entities, including Hydro One), Hydro One is looking to construct a 400-kilometre, 230 kV transmission line from Wawa to Thunder Bay with a total capacity of 650 MW.

Organization Chart



Source: Hydro One investor presentation

Regulation

- Hydro One is a regulated electric utility under the jurisdiction of the OEB.
- The OEB uses a deemed debt-to-common equity structure of 60% to 40% for both transmission and distribution. Debt is divided into 56% long term and 4% short term.
- Approximately 54% of Hydro One's earnings are generated from transmission and the remainder from distribution.

Transmission

- Under the cost-of-service methodology, Hydro One is provided a reasonable opportunity to recover its forecast costs, including operating expenses, depreciation, costs of debt and taxes.
- The Company has no exposure to either commodity price risk or volume risk.
- Hydro One faces the risk of not recovering forecast operating expenses if the actual expenses exceed the forecast expenses, but this risk is considered manageable by DBRS.
- On December 20, 2011, the OEB came to a decision regarding revenue requirements for 2012 of $1,418 million (up from $1,346 million in 2011), translating into an increase of 5% in 2012.
- In 2012, Hydro One's allowed return on equity (ROE) is 9.42%, a decrease from 9.66% in 2011, and deemed common equity is 40%, both of which are at reasonable levels.
- On May 28, 2012, Hydro One filed a rate application with OEB for its 2013/2014 revenue requirement.

Distribution

- The OEB uses a combination of an annual incentive regulation mechanism (IRM) and periodic cost-of-service (COS) reviews to set distribution rates.
- In DBRS's view, the IRM typically creates higher cost-cutting pressure than the COS does; however, the cost pressure has not resulted in a material reduction in the Company's earnings and cash flows.
- The Company is allowed to fully recover its purchased power costs in a timely fashion, eliminating its exposure to power price risk. DBRS views this as a positive factor in the current regulatory system in Ontario (regardless of whether the Company operates under the IRM or the COS).
- In 2012, Hydro One's allowed ROE is 9.42%, a decrease from 9.66% in 2011, and deemed common equity was 40%, both of which are at reasonable levels.
- On May 28, 2012 Hydro One filed an IRM rate application with the OEB for 2013.

Hydro One Inc.

Report Date:
June 20, 2012

Earnings and Outlook

(CA$ millions)	USGAAP 3 mos. Mar. 31 2012	USGAAP 3 mos. Mar. 31 2011	USGAAP 12 mos. Mar. 31 2012	CGAAP For the year ended December 31 2011	CGAAP 2010	CGAAP 2009	CGAAP 2008	CGAAP 2007
Net revenues	1,468	1,460	5,479	5,471	5,124	4,744	4,597	4,655
EBITDA	477	479	1,749	1,751	1,572	1,361	1,451	1,420
EBIT	325	335	1,125	1,135	989	824	903	899
Gross interest expense	(104)	(102)	(414)	(412)	(409)	(369)	(333)	(312)
Earning before taxes	239	247	771	779	630	516	611	604
Net income before non-recurring items	208	209	632	632	579	470	498	399
Reported net income	210	212	639	641	591	470	498	399
Return on equity	13.5%	14.5%	10.1%	10.2%	10.2%	8.9%	10.0%	8.2%

2011 Summary

- Hydro One's earnings have continued to increase over the past five years, mainly due to the Company's increased regulatory asset base, driven by high capex.

Segmented Information	3 mos. Mar. 31		For the year ended December 31				
(CA$ millions)	%	2012	2011	2010	2009	2008	2007 *
Net revenues							
Transmission	48.8%	361	1,389	1,307	1,147	1,212	1,242
Distribution	49.0%	362	1,391	1,280	1,208	1,153	1,142
Other	2.2%	16	63	63	63	51	31
Total net revenues	100.0%	739	2,843	2,650	2,418	2,416	2,415
EBIT by segment							
Transmission	53.5%	174	665	618	469	571	585
Distribution	45.2%	147	478	378	357	335	320
Other	1.2%	4	(8)	(7)	(2)	(3)	(6)
Total EBIT	100.0%	325	1,135	989	824	903	899

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

2012 Outlook

- The Company's earnings for fiscal 2012 are expected improve further due to continued growth in rate base.
- The increase in rate base will be primarily due to Hydro One's growing capex needs in the near future, as it continues to service its aging infrastucture in the trasmission and distribution businesses.

Hydro One Inc.

Report Date:
June 20, 2012

Financial Profile

	USGAAP	USGAAP	USGAAP	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP
	3 mos. Mar. 31		12 mos. Mar. 31	For the year ended December 31				
(CA$ millions)	2012	2011	2012	2011	2010	2009	2008	2007
Net income before non-recurring items	208	209	632	632	579	470	498	399
Depreciation & amortization	139	131	558	550	526	487	502	482
Deferred income taxes and other	5	22	12	29	(35)	(27)	(73)	125
Cash flow (bef. working cap. changes)	352	362	1,201	1,211	1,070	930	927	1,006
Dividends paid	(281)	(42)	(407)	(168)	(28)	(188)	(259)	(325)
Capital expenditures	(296)	(277)	(1,390)	(1,371)	(1,557)	(1,473)	(1,185)	(1,091)
Free cash flow (bef. working cap. changes)	(225)	43	(596)	(328)	(515)	(731)	(517)	(410)
Changes in non-cash work. cap. items	(115)	(122)	203	196	94	(38)	125	135
Net Free Cash Flow	(340)	(79)	(393)	(132)	(421)	(769)	(392)	(275)
Acquisitions & long-term investments	(21)	(18)	(79)	(76)	(263)	(93)	(99)	0
Short-term investments	0	0	0	0	0	0	0	0
Proceeds on asset sales	0	0	0	0	0	0	0	0
Net equity change	0	0	0	0	0	0	0	0
Net debt change	300	50	450	200	845	805	510	285
Other	1	3	23	25	37	15	9	7
Change in cash	(60)	(44)	1	17	198	(42)	28	17
Total debt	8,330	7,846	8,330	8,038	7,778	6,962	6,133	5,615
Cash and equivalents	0	0	0	0	33	0	16	0
Total debt in capital structure	56.6%	56.1%	56.6%	55.5%	56.5%	56.2%	54.5%	53.5%
Cash flow/Total debt	16.9%	18.5%	14.4%	15.1%	13.8%	13.4%	15.1%	17.9%
EBIT gross interest coverage (times)	3.13	3.28	2.72	2.75	2.42	2.23	2.71	2.88
Dividend payout ratio	135.1%	20.1%	64.4%	26.6%	4.8%	40.0%	52.0%	81.5%

2011 Summary

- Overall, Hydro One has maintained a strong financial profile, reflecting a stable balance sheet and reasonable credit metrics for the current ratings.
- Cash flow from operations remains strong, improving over time due to an increased rate base.
- Cash flow deficits persist primarily due to increased developmental capex.
- Unlike other provincially and municipally owned distributors, Hydro One benefits from a flexible dividend program, unrestricted by an earnings threshold level.
- Key credit metrics including leverage, interest coverage and cash flow ratios have remained within the A (high) rating category.

2012 Outlook

- DBRS expects a temporary modest weakening of Hydro One’s key credit metrics over the next several years. However, these ratios are expected to gradually recover when substantial capex plans are completed, and remain reasonable for the current rating category.
- Cash flow from operations is expected to grow over the medium to long term, predominately driven by growth in the asset base.
- DBRS anticipates that free cash flow will continue to be affected by higher capital spending on the Company’s aging infrastructure. Hydro One has budgeted $1.8 billion per annum over the next three years, with maintenance capex expected to be $700 million in 2012, $950 million in 2013 and $1,000 million in 2014.

Description of Operations

- Hydro One is the largest electricity transmission and distribution company in Ontario.
- It operates three distinct business segments:

(1) **Transmission**
- One of the largest in North America, as measured by assets.
- Has 29,000 kilometres of high-voltage network serving its own distribution network, as well as 48 local distribution companies and 93 transmission connected companies.
- Owns and operates approximately 96% of transmission capacity in Ontario, as measured by revenues.

(2) **Distribution**
- Largest distribution system in the province, based on assets, covering about 75% of Ontario.
- Distributes electricity over 120,500 kilometres, reaching approximately 1.4 million customers in a number of municipalities and rural areas.

(3) **Other Businesses**
- Services related to Hydro One Telecom Inc., marketing dark and lit fibre-optic capacity to commercial carriers and telecommunication carriers.

Long-Term Debt Maturities and Bank Lines

- The Company's liquidity profile remains reasonable for the Company's current rating.

(CA$ millions - As at Mar. 31, 2012)	Amount	Draw/LOCs	Available	Maturity
Cash & Cash Equivalents	-	-	-	-
Committed Revolving Facility	1,250	-	1,250	1-Jun-17
Ontario Floating Rate Notes	250	-	250	2014
		Total	**1,500**	

- Hydro One has access to a $1.0 billion commercial paper program supported by an unused revolving facility ($1.25 billion), as well as the holding of Province of Ontario Floating-Rate Notes ($250 million).
- Hydro One has a $3 billion base shelf prospectus, of which approximately $1.9 billion still available for issuance, that expires in September 2013.
- On January 12, 2012, Hydro One issued $300 million in 3.20% notes under its Medium Term Notes (MTN) Program with a maturity date of January 12, 2022.
- On May 22, 2012, Hydro One issued $125 million in 4.0% MTN maturing December 22, 2051 and $300 million in 3.20% MTN maturing January 13, 2022.
- Hydro One's continued access to the capital markets through its MTN and commercial paper programs will be crucial over the next few years, given its infrastructure upgrade mandate. Despite the Company's debt maturities in the medium term, DBRS does not anticipate that Hydro One will have any problem refinancing as needed.

Long-term Debt Maturities

(CA$ millions - As at March 31, 2012)	2012	2013	2014	2015	2016+	Total
Amount	600	600	750	550	5,775	8,275
% of Total	7.3%	7.3%	9.1%	6.6%	69.8%	100.0%

Hydro One Inc.

Report Date:
June 20, 2012

Hydro One

Balance Sheet (CA$ millions)	USGAAP Mar. 31	CGAAP Dec. 31	CGAAP Dec. 31		USGAAP Mar. 31	CGAAP Dec. 31	CGAAP Dec. 31
Assets	2012	2011	2010	**Liabilities & Equity**	2012	2011	2010
Cash & equivalents	0	0	33	S.T. borrowings	32	39	0
Accounts receivable	994	961	911	Accounts payable	146	1,071	884
Inventories	24	25	21	Current portion L.T.D.	600	600	500
Prepaid expenses & other	218	291	224	Deferred tax	0	0	0
				Other current liab.	935	110	156
Total Current Assets	1,236	1,277	1,189	**Total Current Liab.**	1,713	1,820	1,540
Net fixed assets	15,072	14,903	14,061	Long-term debt	7,698	7,399	7,278
Future income tax assets	16	17	19	Deferred income taxes	798	758	693
Goodwill & intangibles	366	357	322	Other L.T. liab.	2,411	1,937	1,830
Investments & others	2,313	1,814	1,731	Shareholders' equity	6,383	6,454	5,981
Total Assets	19,003	18,368	17,322	**Total Liab. & SE**	19,003	18,368	17,322

Balance Sheet & Liquidity & Capital Ratios	USGAAP 3 mos. Mar. 31 2012	USGAAP 3 mos. Mar. 31 2011	USGAAP 12 mos. Mar. 31 2012	CGAAP For the year ended December 31 2011	CGAAP 2010	CGAAP 2009	CGAAP 2008	CGAAP 2007
Current ratio	0.72	1.00	0.72	0.70	0.77	0.59	0.67	0.62
Total debt in capital structure	56.6%	56.1%	56.6%	55.5%	56.5%	56.2%	54.5%	53.5%
Cash flow/Total debt	16.9%	18.5%	14.4%	15.1%	13.8%	13.4%	15.1%	17.9%
Cash flow/Adjusted total debt	16.8%	18.4%	14.3%	15.0%	13.7%	13.3%	15.0%	17.8%
(Cash flow-dividends)/Capex	0.24	1.16	0.57	0.76	0.67	0.50	0.56	0.62
Dividend payout ratio	135.1%	20.1%	64.4%	26.6%	4.8%	40.0%	52.0%	81.5%
Coverage Ratios (times)								
EBIT gross interest coverage	3.13	3.28	2.72	2.75	2.42	2.23	2.71	2.88
EBITDA gross interest coverage	4.59	4.70	4.22	4.25	3.84	3.69	4.36	4.55
Fixed-charge coverage	3.13	3.28	2.71	2.75	2.41	2.24	2.73	2.86
Profitability Ratios								
EBITDA margin	32.5%	32.8%	31.9%	32.0%	30.7%	28.7%	31.6%	30.5%
EBIT margin	22.1%	23.0%	20.5%	20.8%	19.3%	17.4%	19.6%	19.3%
Profit margin	14.2%	14.3%	11.5%	11.6%	11.3%	9.9%	10.8%	8.6%
Return on equity	13.5%	14.5%	10.1%	10.2%	10.2%	8.9%	10.0%	8.2%
Return on capital	7.4%	8.2%	6.0%	6.3%	6.3%	5.7%	6.4%	5.6%

Hydro One Inc.

Report Date:
June 20, 2012

Ratings

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

Rating History

	Current	2011	2010	2009	2008
Commercial Paper	R-1 (middle)	R-1 (middle)	R-1 (middle)	R-1 (middle)	R-1 (middle)
Senior Unsecured Debentures	A (high)	A (high)	A (high)	A (high)	A (high)

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

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Hydro One Inc.

Major Rating Factors

Corporate Credit Rating
A+/Negative/A-1

Strengths:

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

Weaknesses:

- Large capital expenditure program
- Weak financial measures that leave no cushion for the current ratings

Rationale

The ratings on Hydro One Inc., a large, regulated transmission and electricity distribution company in the Province of Ontario (AA-/Negative/A-1), reflect Standard & Poor's Ratings Services' opinion of 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 significant.

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

We believe the company's monopoly position, the business' asset-intensive nature, and regulatory oversight limiting competitive risk all support an excellent business risk profile. Hydro One owns and operates substantially all of Ontario's electricity transmission system, and its distribution service territory covers about 75% of the province. In our view, the business carries relatively low operating risk and exhibits average operational efficiency and reliability.

The Ontario Energy Board's (OEB) regulatory framework supports Hydro One's cash flow stability, and we view cost recovery as generally predictable. We do not expect any near-term shift in energy policy that would affect the credit quality, although we expect the OEB to be mindful of overall electricity costs to consumers in the current economic environment and stagnant load growth in approving proposed prudent spending by utilities. The framework allows for the recovery of prudent transmission and distribution costs and the opportunity to earn a modest-but-predictable return. Furthermore, the company's exposure to commodity risk is limited. Commodity costs flow through to the customer and the utility has no obligation to ensure an adequate supply of electricity in the province.

In our view, Hydro One has a significant financial risk profile. Its cash flow strength relative to its debt obligations has weakened since 2009 due to a material capital expenditure program. Adjusted funds from operations (AFFO)-to-debt declined to 11%-12% in 2009-2011, compared with 14%-15% in 2006-2008. Based on our forecast, we expect that Hydro One will generate annual FFO of about C$1.2 billion-C$1.3 billion in 2012 and 2013, which should be adequate to cover dividend payments and part of the company's capital expenditure program. Our forecast assumes that there will be no material disallowance from the OEB on the company's recent filed transmission cost-of-service application for the next two years. We also assume that it will maintain its reported capital structure within the deemed capital structure of 60% debt layer and keep its capital expenditure level consistent with the OEB approval. Hydro One has budgeted C$1.8 billion of annual capital expenditure for both 2012 and 2013, which we expect it will spend. About 60% of the company's total annual capital expenditure is for its transmission business and the balance is for the distribution business. Although we expect FFO to increase with increasing rate base and cost recovery, we forecast that the utility will still need to increase its total borrowing to support its large negative operating cash flow of about C$500 million per year. As a result, we do not expect to see any meaningful improvement in our key financial measures during our two-year outlook horizon. We forecast that Hydro One's AFFO-to-debt will remain similar to its past three years' levels of about 12%, leaving no cushion at the rating. Still supporting the company's financial risk profile are strong access to capital markets, adequate liquidity, the stability and predictability of its cash flows, and low merger and acquisition risk.

Liquidity

The short-term rating on Hydro One is 'A-1'. We believe the company has adequate liquidity to cover its needs in the near term, even in the event of unforeseen earnings declines. Standard & Poor's assessment incorporates the following expectations and assumptions:

- Hydro One's liquidity sources, including liquid short-term investments, FFO, and credit facility availability, will likely exceed its uses 1.2x or more in the next six months.
- Liquidity sources include a forecast of about C$1.2 billion of annual FFO, access to C$1.25 billion of the company's committed revolving credit facility with a syndicate of banks, and C$161 million liquid short-term investments as of March 31, 2012. The C$1.25 billion credit facility was fully available as of March 31, and will expire in June 2017. Hydro One remains well within its banking covenant of 75% total debt-to-total capital.
- Liquidity uses include C$600 million of maturing debt in Nov. 2012, and about C$1.8 billion of total annual capital expenditures. We did not include the dividend in our calculation because we believe that if the company were under temporary financial duress, it would have the flexibility to temporarily curb dividends to the shareholder.

Hydro One has what we consider good relationships with its banks and good standing in the debt market. We understand that the utility also holds a C$250 million note issued by the province that matures in 2014, which it could liquidate if needed. The company's debt maturities are well spread, in our view, with annual scheduled repayment in the next six years averaging about C$600 million.

Outlook

The negative outlook reflects the outlook on Ontario. Based on our criteria for government-related entities, given a high likelihood of extraordinary support, a SACP of 'a' for Hydro One and our 'AA-' rating on the province, a one- or two-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. We still expect continued predictable regulatory support despite its large capital expenditure program and negative free operating cash flows. In the event of lower-than-expected cash flows and earnings, we expect the utility to maintain its leverage within the deemed capital structure of 60% reported debt-to-capital, AFFO-to-debt of about 12%, and AFFO interest coverage of about 3x, by curtailing its capital spending and additional debt financing. In our view, there is no cushion for Hydro One to deteriorate from our expectations on its key credit measures to maintain the ratings.

Any sustained deterioration of financial measures beyond our expectations, a material adverse regulatory ruling, or market restructuring (such as the assumption of the obligation to supply, not just deliver, electricity) could lead us to lower the existing 'a' SACP and consequently the ratings, regardless of any changes to the province. An improvement in the company's SACP is unlikely without the assurance of a much stronger balance sheet, and stronger cash flow-interest and debt coverage ratios (such as higher than 30% AFFO-to debt).

Business Description

Hydro One owns and operates a low-risk, regulated transmission system that represents about 57% of its total assets as of Dec. 31, 2011. The utility owns and operates substantially all of Ontario's electricity transmission system, which has contributed to it becoming one of the largest transmission companies in North America.

The company also owns and operates a low-risk, regulated distribution system that represents about 40% of its total assets as of Dec. 31. It is one of the country's largest LDCs. Apart from the system operated under Hydro One Brampton, its regulated LDC subsidiary serving customers in the City of Brampton, Ont. (AAA/Stable/--), the system covers mainly rural areas and remote communities in the province. It has a low customer density, covering 75% of Ontario but delivering about 30% of consumed electricity. The marketing of surplus fiber optic capacity through subsidiary Hydro One Telecom is not material to our credit analysis, given the operation's small size (consisting of about 3% of total assets).

Rating Methodology

We base our 'A+' rating on Hydro One on the company's SACP and our view that there is a "high" likelihood that the province would provide timely and sufficient extraordinary support to Hydro One in the event of financial distress. We assess Hydro One's stand-alone credit quality at 'a'.

In accordance with our criteria for government-related entities (GREs), we base our view of a "high" likelihood of extraordinary government support on the following assessment:

- Within the context of our GRE methodology and scale for assessing the importance of a GRE's role to its government owner, we view Hydro One's role as "important" to the province. The utility operates as a profit-seeking enterprise and its credit standing is important to the government because it provides an essential infrastructure service, particularly in the distribution of electricity to remote communities in Ontario. In addition, part of its activities relate to its public policy role for the current government. Through its Green Energy Act, the province is relying on Hydro One to facilitate a smart grid, and the quick connection of small renewable generation assets to the grid. Furthermore, although we do not believe that default or credit stress would lead to a disruption of Hydro

One's physical operations, it would affect the credibility of the entire electricity sector in Ontario, which we believe would have an overall negative economic impact.
- Within the context of our GRE methodology and scale for assessing strength and durability, we view the link between Hydro One and the province as "very strong." The government is a strong and stable shareholder, and it has a policy and track record of providing support to the utility. Government policy has a strong influence on the company's strategic and business plans. Financial support is available to the company from the province through the Ontario Electricity Finance Corp., an established provincial agency with a legislated mandate "to provide financial assistance to the successor corporations of Ontario Hydro," of which Hydro One is one. Ontario's track record is consistent with our view. In the past, the province has offered the utility access to government treasury resources when unforeseen changes in government policy exposed the company's distribution operations to liquidity pressures. We expect that liquidity support would be available again under similar circumstances. Furthermore, the province appoints Hydro One's board of directors, and the government reviews the company's business plan and dividend policy before implementation. Management updates government staff on the company's monthly financial and operational performance.

After the government had considered selling Crown assets, which include Hydro One, since December 2009, the province's finance minister indicated in July 2010 that there would be no short-term consideration of doing so. While we maintain our view that the company's privatization could weaken its link with the province and the likelihood of extraordinary support in times of need, we don't consider such an event imminent. Should the idea of privatization resurface, we would treat this as an event risk and reevaluate the likelihood of extraordinary support at that time.

Excellent Business Risk Profile

The stable regulatory regime supports credit quality

The OEB provides regulatory oversight of Hydro One's operations. Prudent costs incurred are generally recovered through tariffs, but rate base adjustments can lag capital requirements up to three years unless the company returns to the regulator with a resource consuming, full cost-of-service application each year. We understand that the company's strategy is to file a full cost-of-service application more frequent than a usual four-year cycle in view of rapid fixed assets growth, which mitigate the potential time lag between its capital expenditure spending and cost recovery through rate-base adjustments. To date, the OEB has been supportive to this approach. The utility filed its transmission cost-of-service rate application recently for 2013 and 2014 and its distribution rate application (under the incentive regulated mechanism) for 2013.

The OEB sets rates by estimating Hydro One's revenue requirement, given forecast consumption. The company submits separate transmission and distribution applications to the OEB, which determines revenue requirements on a forward test-year basis. The regulated revenue requirement includes the cost of capital based on a deemed capital structure of 60% debt and a modest return on equity (ROE). The allowed return on equity is based on a formula linked to long-term Government of Canada (GOC; AAA/Stable/A-1+) bonds, long-term utility bond spreads, plus a modest risk premium.

There is a long history of regulated entities in Ontario being allowed to recoup unforeseen, previously incurred costs (regulatory assets) and having to refund the customer (regulatory liabilities) after-the-fact through rates. Cash recovery (or repayment) is subject to a prudency review and regulatory approval. Depending on the magnitude, the OEB may spread the recovery across several years to avoid rate shock. To date, mandated refunds to customers have not caused undue financial duress for most utilities. For Hydro One, total unrecovered regulatory assets and liabilities on the balance sheet as of Dec. 31, 2011, were C$325 million (net of regulatory future income tax asset) and C$660 million, respectively, representing about 2% of total assets and 5.5% of total liabilities, respectively. From a credit perspective, we do not view these as a concern.

Temperate regulatory relationship, but spending budget could be under tighter scrutiny

Large differences between rate applications and final regulatory decisions could cause a rating concern as it might indicate increased regulatory risk. The OEB acknowledges the company's higher cost of operations due to low density franchise and has generally accepted its forward cost estimates without significant haircuts (see table 1). With much lower customer density than that of its municipal peers, the system is by nature more expensive on a capital- and operating-cost per customer basis.

Although we do not expect allowing recovery of prudent operating and capital spending to change, we expect that the OEB would, in its approval of prudent spending, be mindful of overall electricity costs to consumers in the current weak economy, stagnant load growth, as well as the province's priority to green energy, smart grid, and conservation and demand management (CDM). Nevertheless, there have been no material differences between the company's requested revenue requirement and the OEB approved amount.

Table 1

Hydro One Inc.--Requested vs. Approved Revenue Requirement

(Mil. C$)	Year*	Requested revenue requirement	Approved revenue requirement	Approved revenue requirement
Distribution	2010	1,150	1,146	0.3% lower than requested
	2011	1,264	1,218	3.6% lower than requested
Transmission	2011	1,446	1,346	6.9% lower than requested
	2012	1,547	1,418	8.3% lower than requested

*2012 U.S. generally accepted accounting principles used for rate-setting purposes.

Asset-intensive nature of monopoly business reduces competitive risk

Although some competitive pressures exist, Hydro One's existing transmission system is largely shielded from direct competition due to its natural monopoly position. However, the company does not hold a legal monopoly on its service territory. There is no restriction on other transmission businesses' building and operating transmission networks in Ontario. However, the capital cost that would be involved in large-scale duplication of the network reduces the risk of bypass. Should bypass strand an individual asset, it is likely that tariffs would be rebalanced across remaining customers with minimal financial impact, given the territory's size.

Low-risk operations

Hydro One's regulated retail obligation is also a relatively low-risk operation. The LDC is not engaged in commodity price or volume risk management and does not engage in contractual commitments to ensure adequate supply. Energy costs are a pass-through to consumers with no markup. Any variance is recouped or rebated through the OEB-regulated retail price in the following fiscal quarter.

The operational performance of Hydro One's transmission assets remains good; the system has achieved top quartile transmission reliability compared with that of other large Canadian peers (as reported to the Canadian Electricity Association). The electricity market rules and transmission license governing Hydro One's transmission operations required the transmitter to comply with reliability standards established by the North American Reliability Corp. and Northeast Power Coordinating Council Inc. Those standards include penalties for noncompliance. At the time of publication, Hydro One complied with the standards and had never paid any penalties.

The company's distribution reliability, although consistently weaker than that of other rated municipal peers largely because of its expansive rural service territory, does not pose a material credit risk. The regulator tracks performance metrics but has not yet imposed generic industry standards or penalties for substandard service.

Well-diversified economy in the company's service territory

Hydro One owns and operates substantially all of Ontario's electricity transmission system, accounting for about 96% of the province's transmission capacity by revenue. Its distribution system is the largest in Ontario and spans about 75% of the province, serving the more rural areas and remote communities of Ontario except for the company's Brampton network business.

The province has a large and well-diversified economy, and Hydro One delivers an essential service. The government estimates that real GDP slowed to 1.8% in 2011 from a 3% gain in 2010. According to the government's estimates, real GDP growth should advance a further 1.7% in 2012. The recession's impact was felt chiefly in the construction and manufacturing sectors (vehicle assembly and part production). Nevertheless, Ontario has a large and well-diversified economy with depth and scale in many sectors, and the provincial economy has a number of key strengths, including a large, well-educated workforce; and proximity to important northeastern U.S. markets. While recognizing that uncertainty about the tenuous recovery in Europe and the U.S. is a risk to the economic outlook, our province analyst believes that the government's forecast real GDP growth of 1.7% for 2012 is achievable.

The company estimates about 1% of load growth associated with economy growth in Ontario economy. However, Hydro One expects the overall load to decline 1.5% mainly due to the impact of CDM and embedded generation. This does not cause us a significant concern on the company's future financial performances as long as there is no large discrepancy between its estimated and actual load growth.

Customer profile supports stable revenues

We believe the diversity of Hydro One's customer base supports the overall stability of its revenues and severely limits exposure to any particular customer or customer class. In the transmission business, municipally owned investment-grade LDCs and the utility's own distribution business collect transmission revenues and forward them to Hydro One through the IESO. The company's distribution operation also collects distribution revenues from a relatively stable customer base that is about 58% residential, about 28% commercial, 7% large industrial, and 7% embedded LDCs (on a distribution revenues basis in 2011).

Renewal of an aging labor force remains a challenge

An aging workforce remains an issue that could affect Hydro One's operations. It expects about 21% of its workforce to be eligible for retirement by 2013. The company is making an effort to address the issue by employing a larger number of apprentices, investing in co-op power engineering programs with universities, and outsourcing some capital programs. During this period of workforce renewal, we expect staff levels to be higher than normal as new employees are trained, and to enable the execution of the large capital program. The utility's cost-of-service determination includes the related labor costs. The company had about 5,781 permanent employees at end of 2011, up 6.5% from 2009. The majority of its employees are represented by either the Power Workers' Union (PWU) or the Society of Energy Professionals. The collective agreement with Society and PWU will expire March 31, 2013.

Significant Financial Risk Profile

Consistent financial policies

Hydro One's financial policies have historically been consistent. While total leverage increased in the past three years to support the company's large capital program, Hydro One intends to maintain its capital structure within the regulatory deemed structure (reported debt to capital of 60%). Debt maturities are well-spread, in our view, with annual scheduled repayment in the next six years averaging about C$600 million. Derivative instruments manage interest rate exposure nonspeculatively. The utility is not exposed to foreign currency risk other than through the purchase of some materials. The company discloses its target to maintain an 'A' long-term rating in its annual report.

The board of directors declares common dividends after considering management's recommendation based on its operating results. Also the shareholder agreement requires the company to consult with its owner, the province, regarding dividend payments. It is my understanding that the company could reduce dividend payments to help satisfy its cash requirement and to maintain its capital structure within the regulatory deemed capital structure of 60% debt layer.

Management advocates an enterprise-wide approach to risk management directed at balancing regulatory, strategic, operational and financial risk exposure, and the returns allowed within the Ontario regulatory framework

Accounting

Hydro One prepared consolidated financial statements in accordance with Canadian generally accepted accounting principles (GAAP) until Dec.31, 2011. Effective Jan 1, 2012, the company adopted U.S. GAAP. Similar to Canadian GAAP, U.S. GAAP allows utilities to defer costs or revenues that they expect the regulator to allow them to recover to the balance sheet. Assets and liabilities are recouped from or rebated to customers in periods, typically varying from one-to-four years. To date, regulatory disallowances for assets and liabilities that Hydro One and other Ontario-based utilities have declared have been minor. The change in accounting practice itself should not affect our credit analysis in absence of changes in the company's economic substance.

Material adjustment Standard & Poor's made to the balance sheet (see table 2) includes postretirement benefit obligations (about 15% of total adjusted debt). Other adjustments are not material. Hydro One treats its C$323 million 5.5% cumulative preferred shares as equity. The province holds the shares, which 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 at the province's option; however, Hydro One, at its own discretion, can pay all or part of the redemption price by issuing additional common shares to the province. We do not expect them to do so in the near term. The shares carry voting rights under limited circumstances and rank in priority above the common shares upon liquidation. The company can issue an unlimited number of preferred and common shares.

Hydro One has C$133 million of goodwill on its balance sheet that arose when it acquired LDCs for totals exceeding their fair value. The OEB does not recognize goodwill in the regulated rate base used to determine electricity tariffs. The amount is not material to our analysis but indicates the risk to the balance sheet and Hydro One's returns that acquisitions could pose.

Table 2

Reconciliation Of Hydro One Inc. Reported Amounts With Standard & Poor's Adjusted Amounts (Mil. C$)

	--Fiscal year ended Dec. 31, 2011--									
Hydro One Inc. reported amounts	**Debt**	**Shareholders' equity**	**Revenues**	**EBITDA**	**Operating income**	**Interest expense**	**Cash flow from operations**	**Cash flow from operations**	**Dividends paid**	**Capital expenditures**
Reported	8,038.0	6,454.0	5,471.0	1,751.0	1,135.0	359.0	1,360.0	1,360.0	168.0	1,447.0
Standard & Poor's adjustments										
Operating leases	43.7	N/A	N/A	2.3	2.3	2.3	4.2	4.2	N/A	9.9
Postretirement benefit obligations	1,424.2	(981.5)	N/A	140.0	140.0	64.0	14.4	14.4	N/A	N/A
Capitalized interest	N/A	N/A	N/A	N/A	N/A	58.0	(58.0)	(58.0)	N/A	(58.0)
Non-operating income (expense)	N/A	N/A	N/A	N/A	15.0	N/A	N/A	N/A	N/A	N/A
Reverse changes in working-capital	N/A	N/A	N/A	N/A	N/A	N/A	N/A	(196.0)	N/A	N/A
Debt--accrued interest not included in reported debt	85.0	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Total adjustments	1,553.0	(981.5)	0.0	142.3	157.3	124.3	(39.4)	(235.4)	0.0	(48.1)
Standard & Poor's adjusted amounts	**Debt**	**Equity**	**Revenues**	**EBITDA**	**EBIT**	**Interest expense**	**Cash flow from operations**	**Funds from operations**	**Dividends paid**	**Capital expenditures**
Adjusted	9,591.0	5,472.5	5,471.0	1,893.3	1,292.3	483.3	1,320.6	1,124.6	168.0	1,398.9

N/A--Not applicable.

Profitability is constrained by the regulatory compact but is predictable

Largely dictating Hydro One's profitability is the regulatory compact that generally allows the company to earn a modest return. The OEB announced in December 2009 a change in cost of capital computation formula, originally put in place since 1998. The new formula is now linked to both utility bond spreads and the long-term GOC bond rate; the often inverse relationship between the two rates could reduce volatility of the future ROE adjustments. The revised formula resulted in favorable ROE adjustments on Hydro One's 2011-2012 transmission rates and 2010-2011 distribution rates (see table 3). The company estimated that a 1% decrease in the forecast long-term GOC bond yield or utility bond spread used in setting rates could reduce net income in transmission about C$18 million and that in distribution about C$10 million.

Weather-induced changes in energy delivered subject Hydro One's cash flows to modest fluctuations that we factor into our rating opinion. The transmission tariff is levied on monthly peak load. The distribution tariff is levied on a mix of fixed- and variable-charges for each of 12 customer classes (formerly 80) the OEB approved in late 2008.

Table 3

Hydro One Inc.--Historical Parameters Used To Set Regulated Rates

Fiscal year ended Dec. 31	Ratesetting year	Approved transmission rate base (used to determine revenue requirement)	Approved distribution rate base (used to determine revenue requirement)	OEB-deemed capital structure (used to set rates)	OEB-allowed ROE in rates (%)§
2004	May 1, 2004	C$5.7 billion	Rate base was not adjusted	60% debt; 4% preferred equity; 36% common equity	9.88
2005	May 1, 2005	C$5.7 billion	Rate base was not adjusted	60% debt; 4% preferred equity; 36% common equity	9.88
2006	May 1, 2006	Rate base was not adjusted	C$3.7 billion	60% debt; 40% equity	9.00 (distribution); 9.88 (transmission)
2007*	May 1, 2007	C$ 6.3 billion	Rate base was not adjusted	56% long-term debt; 4% short-term debt; 40% equity	9.00 (distribution); 8.35 (transmission)
2008	May 1, 2008	Rate base was not adjusted	C$4.3 billion	56% long-term debt4% short-term debt 40% equity	8.57 (distribution); 8.35 (transmission)
2009	May 1, 2009	C$7.0 billion	Rate base was not adjusted	56% long-term debt; 4% short-term debt; 40% equity	8.35 (distribution); 8.01 (transmission)
2010	May 1, 2010	C$7.6 billion	C$4.8 billion	56% long-term debt; 4% short-term debt; 40% equity	9.85 (distribution); 8.39 (transmission)
2011	Jan. 1, 2011	C$7.9 billion	C$5.1 billion	56% long-term debt; 4% short-term debt; 40% equity	9.66 (distribution); 9.66 (transmission)
2012	Jan. 1, 2012	C$8.8 billion	Rate base was not adjusted	56% long-term debt; 4% short-term debt; 40% equity	N.A. (distribution); 10.41 (transmission)

*The OEB's second generation incentive rate mechanism resulted in increased distribution rates for Hydro One without a full cost of service application. §After 2005, allowed ROEs were determined based on a formula linked to long-term Government of Canada rates. ROE--Return on equity. N.A.--Not available.

Manageable debt profile and financial flexibility

Although the company has about C$600 million maturing in 2012 and 2013, we believe Hydro One's debt profile is manageable, in view of its good access to debt capital market and regulated cash flow. The company's financing strategy limits debt maturities in any single year from exceeding C$600 million (about 8% of current debt load). Furthermore, about 50% of Hydro One's C$8 billion reported debt outstanding as of Dec. 31, 2011, had a maturity date of more than 10 years and the company targets a weighted-average term of 12-18 years for its debt portfolio.

As a fully government-owned company, Hydro One has effectively no access to the equity market, although we do not consider this a rating concern. The company could derive additional financial flexibility from its ability to reduce dividends as demonstrated in 2009 and 2010, when it reduced dividend payments C$137 million and C$160 million, respectively (see table 4). Furthermore, about 50% of its total capital expenditures in 2013 represent the sustainment requirements of its aging infrastructure. Under extraordinary conditions, the government shareholder is also a potential source of financing and backup liquidity. Although access to new equity in the form of cash injections from the shareholder is unlikely, partial or full reduction of dividend payments is a credible option for Hydro One.

Table 4

Hydro One Inc.--Dividend Payments History					
(Mil. C$)	**2011**	**2010**	**2009**	**2008**	**2007**
Common dividend	150	10	170	307	332
Preferred dividend	18	18	18	18	18
Common dividend payout ratio (%)	24.1	1.7	37.6	64	87.1

Pension shortfall is likely to rise

We believe Hydro One's pension fund shortfall is manageable. The OEB recognizes pension contribution costs as a prudent component of the cost-of-service and so they are largely recovered through rates. The company estimates that it would need to make a pension contribution of C$154 million in 2013 (subject to an actuarial valuation effective Dec. 31, 2012). While we expect pension obligations to increase as the utility's workforce ages, the size of pension deficits would also depend on future discount rates and asset value.

Hydro One uses derivatives to manage interest-rate exposure

Management uses derivative financial instruments and interest rate swap contracts primarily to manage exposure to interest rate fluctuations. Hydro One manages related credit risk by dealing primarily with highly-rated counterparties. Employing master agreements that allow for net settlements reduces exposure to large collateral calls. Using derivatives, the company generally maintains less than 20% of debt (including debt maturing within the year) at floating rates. Hydro One carries no debt-related foreign exchange exposure, with all debt in Canadian dollars.

Table 5

Hydro One Inc.--Peer Comparison				
Industry Sector: Electric Utility				
	Hydro One Inc.*§	**Statnett SF§**	**AltaLink L.P.§**	**Toronto Hydro Corp.***
Rating as of June 27, 2012	A+/Negative/A-1	A+/Stable/A-1	A-/Stable/--	A/Stable/--
	--Average of past three fiscal years--			
Currency (mil.)	C$	NOK	C$	C$
Revenues	5,113.0	5,202.0	314.0	2,627.5
EBITDA	1,703.7	2,220.7	210.3	323.6
Net income from continuing operations	567.3	906.0	69.8	68.3
Funds from operations (FFO)	1,042.6	1,717.0	148.1	241.4
Capital expenditures	1,475.9	1,946.7	436.6	345.3
Free operating cash flow	(354.9)	(346.7)	(297.6)	(83.6)
Dividends paid	128.0	315.3	27.3	27.7
Discretionary cash flow	(482.9)	(662.0)	(324.9)	(111.3)
Cash and short-term investments	133.3	0.0	12.2	231.9
Debt	8,844.1	11,667.6	1,130.5	1,546.3
Preferred stock	323.0	0.0	0.0	0.0
Equity	5,223.8	6,823.6	833.1	1,020.7

Table 5

Hydro One Inc.--Peer Comparison (cont.)				
Debt and equity	14,067.9	18,491.2	1,963.6	2,567.0
Adjusted ratios				
FFO interest coverage (x)	3.0	5.4	3.4	3.5
FFO/debt (%)	11.8	14.7	13.1	15.6
Free operating cash flow/debt (%)	(4.0)	(3.0)	(26.3)	(5.4)
Discretionary cash flow/debt (%)	(5.5)	(5.7)	(28.7)	(7.2)
Net cash flow/capex (%)	62.0	72.0	27.7	61.9
Debt/EBITDA (x)	5.2	5.3	5.4	4.8
Total debt/debt plus equity (%)	62.9	63.1	57.6	60.2
Return on common equity (%)	9.1	12.7	8.4	6.4
Common dividend payout ratio (unadjusted; %)	20.0	16.4	39.1	40.6

*Distribution company. §Tranmission company.

Table 6

Hydro One Inc.--Financial Summary					
Industry Sector: Electric Utility					
	--Fiscal year ended Dec. 31--				
(Mil. C$)	**2011**	**2010**	**2009**	**2008**	**2007**
Rating history	A+/Stable/A-1	A+/Stable/A-1	A+/Stable/A-1	A+/Stable/A-1	A/Positive/A-1
Revenues	5,471.0	5,124.0	4,744.0	4,597.0	4,655.0
EBITDA	1,893.3	1,720.3	1,497.5	1,486.7	1,505.8
Net income from continuing operations	641.0	591.0	470.0	498.0	399.0
Funds from operations (FFO)	1,124.6	1,087.0	916.2	1,006.7	884.6
Capital expenditures	1,398.9	1,516.0	1,512.7	1,284.5	1,071.9
Free operating cash flow	(78.3)	(352.0)	(634.6)	(149.7)	(52.3)
Dividends paid	168.0	28.0	188.0	259.0	325.0
Discretionary cash flow	(246.3)	(380.0)	(822.6)	(408.7)	(377.3)
Cash and short-term investments	228.0	172.0	0.0	16.0	0.0
Debt	9,591.0	8,917.8	8,023.6	6,936.9	6,367.5
Preferred stock	323.0	323.0	323.0	323.0	323.0
Equity	5,472.5	5,351.7	4,847.2	4,766.2	4,530.8
Debt and equity	15,063.4	14,269.5	12,870.7	11,703.1	10,898.3
Adjusted ratios					
EBITDA interest coverage (x)	3.9	3.5	3.3	4.4	4.6
FFO interest coverage (x)	3.2	3.0	2.8	4.0	3.7
FFO/debt (%)	11.7	12.2	11.4	14.5	13.9
Discretionary cash flow/debt (%)	(2.6)	(4.3)	(10.3)	(5.9)	(5.9)
Debt/debt and equity (%)	63.7	62.5	62.3	59.3	58.4
Return on common equity (%)	9.6	9.7	8.0	9.5	7.9
Common dividend payout ratio (unadjusted; %)	24.1	1.7	37.6	64.0	87.1

Related Criteria And Research

- Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers, Sept. 28, 2011
- Rating Government-Related Entities: Methodology And Assumptions, Dec. 9, 2010
- Criteria Methodology: Business Risk/Financial Risk Matrix Expanded, May 27, 2009
- Key Credit Factors: Business And Financial Risks In The Investor-Owned Utilities Industry, Nov. 26, 2008
- 2008 Corporate Criteria: Analytical Methodology, April 15, 2008

Ratings Detail (As Of June 27, 2012)		
Hydro One Inc.		
Corporate Credit Rating		A+/Negative/A-1
Commercial Paper		
Local Currency		A-1
Canadian CP Rating Scale		A-1(MID)
Senior Unsecured		A+
Corporate Credit Ratings History		
25-Apr-2012	*Foreign Currency*	A+/Negative/A-1
03-Jun-2008		A+/Stable/A-1
26-Mar-2007		A/Positive/A-1
25-Apr-2012	*Local Currency*	A+/Negative/A-1
03-Jun-2008		A+/Stable/A-1
26-Mar-2007		A/Positive/A-1
Business Risk Profile		Excellent
Financial Risk Profile		Significant
Related Entities		
Ontario Power Generation Inc.		
Issuer Credit Rating		A-/Stable/--
Ontario (Province of)		
Issuer Credit Rating		AA-/Negative/A-1+
Commercial Paper		
Foreign Currency		A-1+
Senior Unsecured		AA-
UMH Energy Partnership		
Senior Secured		A/Stable

*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.

DBRS
Insight beyond the rating.

Rating Report

Report Date:
August 22, 2012

Previous Report:
June 20, 2012

Hydro One Inc.

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The Company

Hydro One Inc. is the largest regulated electric transmission and distribution utility in Ontario, serving more than 97% of the province's transmission throughput. The Company also owns a fibre-optic network across most of Ontario. Hydro One is wholly owned by the Province of Ontario (rated AA (low)).

Commercial Paper

Authorized Limit of $1.0 Billion

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 and Commercial Paper ratings of Hydro One Inc. (Hydro One or the Company) at A (high) and R-1 (middle), respectively, both with Stable trends. The rating confirmation is based on the Company's low-risk regulated transmission and distribution businesses, a supportive regulatory environment in Ontario and the Company's strong financial profile. Hydro One's regulated transmission and distribution businesses in Ontario account for virtually 100% of total earnings.

Regulation in Ontario has remained supportive for Hydro One. The Ontario Energy Board (OEB) is expected to continue to allow the Company to maintain coverage, cash flow and leverage ratios in line with the current rating category due to the government's commitment to address Hydro One's aging infrastructure while meeting the continued growth of electricity consumption and renewable energy developments in the province without compromising reliability. The confirmation assumes that Hydro One's transmission and distribution revenue base will continue to grow considerably to support a high level of capital expenditure (capex), which is expected to continue to far exceed depreciation. Project execution risk is expected to be manageable; the Company is experienced in managing projects and is focused on mitigating the risk of cost overruns. On June 19, 2012, Hydro One's Bruce to Milton Transmission line came in-service, which transports 3,000 megawatts (MW) of power from nuclear and wind facilities.

Hydro One's credit metrics have remained relatively stable over the past four years. The Company generated a cash flow deficit of approximately $312 million for the six months ended June 30, 2012 (H1 2012), which was financed by debt. The deficit was largely driven by ongoing high capex attributable to the Advanced Distribution System project and infrastructure sustainability spending (expected spending of approximately $1.8 billion per annum for 2013 and 2014). As of June 30, 2012, Hydro One anticipates that capex for 2012 will be $165 million below the planned $1.8 billion due to changes in the cost and timing of certain transmission projects and lower distribution development. Key credit metrics are expected to remain reasonable for the current rating category with debt leverage maintained in the 55% to 60% range.

Rating Considerations

Strengths
(1) Low business risk
(2) Strong financial profile
(3) Extensive franchise area
(4) Indirect support from the province

Challenges
(1) High level of planned capital expenditure
(2) Project construction risk
(3) Significant external financing requirements
(4) Limited access to equity markets

Financial Information

	USGAAP	USGAAP	Mix	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP
Hydro One	**6 mos. Jun. 30**		**12 mos. Jun. 30**	**For the year ended December 31**				
(CA$ millions where applicable)	**2012**	**2011**	**2012**	**2011**	**2010**	**2009**	**2008**	**2007**
EBIT gross interest coverage (times)	2.90	2.89	2.76	2.75	2.42	2.23	2.71	2.88
Total debt in capital structure	57.3%	55.7%	57.3%	55.5%	56.5%	56.2%	54.5%	53.5%
Cash flow/Total debt	15.2%	16.5%	14.0%	15.1%	13.8%	13.4%	15.1%	17.9%
(Cash flow-dividends)/Capex (times)	0.53	0.88	0.57	0.72	0.66	0.47	0.52	0.62
Net income before non-recurring items	375	349	658	632	579	470	498	399
Cash flow from operations	666	648	1,229	1,211	1,070	930	927	1,006

Rating Considerations

Strengths
(1) **Low business risk.** Almost all of the Company's earnings are contributed by its low-risk regulated distribution and transmission businesses, which operate under a reasonable regulatory framework.

(2) **Strong financial profile.** The Company continues to maintain strong credit metrics and a healthy balance sheet (debt-to-capital ratio at 57.3%, EBIT interest coverage at 2.76 times and cash flow-to-debt at 14%, for the 12 months ended June 30, 2012).

(3) **Extensive franchise area.** Hydro One owns the largest transmission and distribution businesses in Ontario. The Company serves approximately 96.6% of the province's transmission throughput. The distribution component of the Company spans approximately 75% of the province, serving approximately 1.4 million customers (rural and urban) as well as 435 large-user customers.

(4) **Indirect support from the province.** The Province of Ontario (the Province) provides indirect support to Hydro One with respect to the flexibility of its dividends, which allows Hydro One to maintain its leverage below the 60% set by the OEB. However, DBRS notes that the ratings of Hydro One are on a stand-alone basis.

Challenges
(1) **High level of planned capital expenditure.** Hydro One is currently in the midst of an aggressive build-out program that will continue over the next several years. Capex is expected to be approximately $5.5 billion over the next three years. Therefore, DBRS expects that annual capex could exceed operating cash flows by approximately $700 million to $800 million per year over that time frame. These sizable free cash flow deficits, combined with lengthy construction times, will continue to put temporary pressure on the balance sheet and coverage ratios during the build-out.

(2) **Project construction risk.** The size and magnitude of Hydro One's upcoming designated projects, combined with the continued increases in material and labour costs and the significant number of interveners involved, could potentially expose Hydro One to rising project costs beyond the amounts 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.

(3) **Significant external funding requirements.** Significant external funding is required to finance the potentially sizable free cash flow deficits expected over the near to medium term. Maintaining adequate access to the public debt markets (term and commercial paper) is critical to the Company during this key build-out phase.

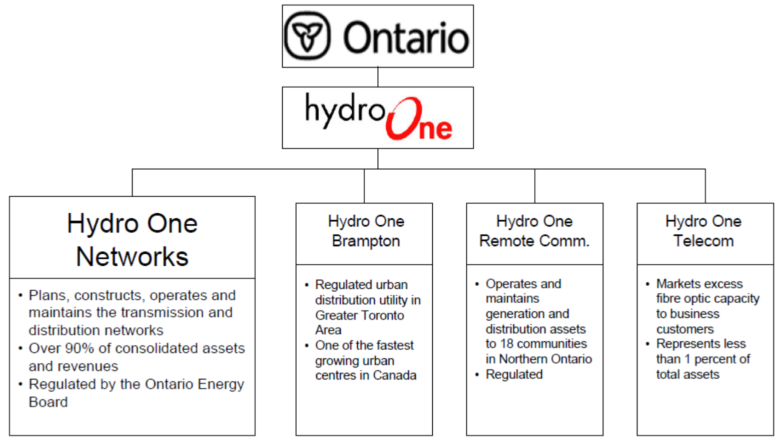
(4) **Limited access to equity markets.** Hydro One's ownership structure (100% owned by the Province) limits its ability to access the equity markets directly. As a result, Hydro One's additional cash flow needs are being financed largely through its retained earnings and short and long-term debt issuances.

Major Projects (Potential and Under Construction)

- **West of London Transmission Lines.** The aim of the projects is to add between 500 MW and 1,000 MW to the grid. These projects are in the early stages with an expected completion date in 2017, contingent on the necessary regulatory approvals. Estimated costs range from $300 million to $450 million.
- **East-West Tie Project.** Through the East-West Tie LP (an equal partnership between three entities, including Hydro One), Hydro One is looking to construct a 400-kilometre, 230 kilovolt (kV) transmission line from Wawa to Thunder Bay with a total capacity of 650 MW.

*The figures above are released by the Ontario Power Authority and are still in the early stages.

Organization Chart



Source: Hydro One investor presentation

Description of Operations

- Hydro One is the largest electricity transmission and distribution company in Ontario.
- Hydro One Telecom Inc. is the unregulated operations of the Company that accounts for less than 1% of total assets. It markets dark and lit fibre-optic capacity to commercial and telecommunication carriers.
- It operates two principal distinct business segments:

(1) **Transmission**
- One of the largest in North America, as measured by assets.
- Has 29,000 kilometres of high-voltage network serving its own distribution network, as well as 48 local distribution companies and 93 transmission connected companies.
- Owns and operates approximately 96.6% of transmission capacity in Ontario, as measured by revenues.

(2) **Distribution**
- Largest distribution system in the province, based on assets, covering about 75% of Ontario.
- Distributes electricity over 120,500 kilometres, reaching approximately 1.4 million customers in a number of municipalities and rural areas.

Regulation

- Hydro One is a regulated electric utility under the jurisdiction of the OEB.
- The OEB uses a deemed debt-to-common equity structure of 60% to 40% for both transmission and distribution. Debt is divided into 56% long term and 4% short term.
- Approximately 60% of Hydro One's earnings are generated from transmission and the remainder from distribution.
- Hydro One is subject to general regulatory risks faced by companies that operate under a regulatory framework. This includes the risk of getting lower approved rates than requested, as well as not being able to recover forecasted operating expenses if the actual expenses exceed the forecasted.

Transmission
- Under the cost-of-service methodology, Hydro One is provided a reasonable opportunity to recover its forecast costs, including operating expenses, depreciation, costs of debt and taxes.
- The Company has no exposure to either commodity price risk or volume risk.
- On December 20, 2011, the OEB came to a decision regarding revenue requirements for 2012 of $1,418 million (up from $1,346 million in 2011), translating into an increase of 5% in 2012.
- In 2012, Hydro One's allowed return on equity (ROE) is 9.42%, a decrease from 9.66% in 2011, and deemed common equity is 40%, both of which are at reasonable levels.

- On December 20, 2011, the OEB approved new transmission tariff rates for 2012 that reflect the inclusion of new capital investments in Hydro One's transmission rate base effective January 1, 2012.
- On May 28, 2012, Hydro One filed a revenue requirement and cost-of-service rate application for the 2013 and 2014 transmission rates. In it, it requested approval for revenue requirements of approximately $1,464 million and $1,557 million for 2013 and 2014, respectively (an increase of less than 1% in 2013 and 9% in 2014).

Distribution

- The OEB uses a combination of an annual incentive regulation mechanism (IRM) and periodic cost-of-service (COS) reviews to set distribution rates.
- In DBRS's view, the IRM typically creates higher cost-cutting pressure than the COS does; however, the cost pressure has not resulted in a material reduction in the Company's earnings and cash flows.
- The Company is allowed to fully recover its purchased power costs in a timely fashion, eliminating its exposure to power price risk. DBRS views this as a positive factor in the current regulatory system in Ontario (regardless of whether the Company operates under the IRM or the COS).
- In 2012, Hydro One's allowed ROE is 9.42%, a decrease from 9.66% in 2011, and deemed common equity was 40%, both of which are at reasonable levels.
- On May 28, 2012, Hydro One filed an IRM rate application with the OEB for 2013, to be effective January 1, 2013. The Company requested the approval of a distribution rate increase for residential customers of approximately 2.9%.

Hydro One Inc.

Report Date:
August 22, 2012

Earnings and Outlook

(CA$ millions where applicable)	USGAAP 6 mos. Jun. 30 2012	USGAAP 6 mos. Jun. 30 2011	Mix 12 mos. Jun. 30 2012	CGAAP For the year ended December 31 2011	CGAAP 2010	CGAAP 2009	CGAAP 2008	CGAAP 2007
Net Sales	1,458	1,422	2,879	2,843	2,650	2,418	2,416	2,415
EBITDA	918	885	1,784	1,751	1,572	1,361	1,451	1,420
EBIT	608	590	1,153	1,135	989	824	903	899
Gross interest expense	210	204	418	412	409	369	333	312
Earning before taxes	429	413	795	779	630	516	611	604
Net income before non-recurring items	375	349	658	632	579	470	498	399
Reported net income	379	354	666	641	591	470	498	399
Return on equity	11.5%	11.4%	10.3%	10.2%	10.2%	8.9%	10.0%	8.2%

2011 Summary

- Hydro One's earnings have continued to increase over the past five years, mainly due to the Company's increased regulatory asset base, driven by high capex.

Segmented Information	6 mos. Jun. 30		For the year ended December 31						
(CA$ millions)	Percent	2012	2011	2010	2009	2008	2007 *	2006	2005
Net Sales									
Transmission	50.1%	731	1,389	1,307	1,147	1,212	1,242	1,245	1,310
Distribution	47.7%	696	1,391	1,280	1,208	1,153	1,142	1,052	954
Other	2.1%	31	63	63	63	51	31	27	21
Total Revenues	100.0%	1,458	2,843	2,650	2,418	2,416	2,415	2,324	2,285
EBIT by segment									
Transmission	60.0%	365	665	618	469	571	585	614	711
Distribution	40.6%	247	478	378	357	335	320	323	305
Other	-0.7%	(4)	(8)	(7)	(2)	(3)	(6)	(8)	(10)
Total EBIT	100.0%	608	1,135	989	824	903	899	929	1,006

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

2012 Outlook

- Earnings continued to increase in the first half of 2012 (by $26 million from H1 2011) mainly due to increased rate base and higher demand for energy.
- The Company's earnings for fiscal 2012 are expected to improve further due to continued growth in rate base.
- The increase in rate base will be primarily driven by Hydro One's growing capex needs in the medium term, as it continues to service its aging infrastucture in the trasmission and distribution businesses.

Financial Profile

(CA$ millions where applicable)	USGAAP	USGAAP	Mix	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP
	6 mos. Jun. 30		**12 mos. Jun. 30**	**For the year ended December 31**				
	2012	**2011**	**2012**	**2011**	**2010**	**2009**	**2008**	**2007**
Net income before non-recurring items	375	349	658	632	579	470	498	399
Depreciation & amortization	279	263	566	550	526	487	502	482
Deferred income taxes and other	12	36	5	29	(35)	(27)	(73)	125
Cash flow from operations	666	648	1,229	1,211	1,070	930	927	1,006
Dividends paid	(311)	(84)	(395)	(168)	(28)	(188)	(259)	(325)
Capital expenditures	(667)	(640)	(1,474)	(1,447)	(1,570)	(1,566)	(1,284)	(1,091)
Free cash flow (bef. working cap. changes)	(312)	(76)	(640)	(404)	(528)	(824)	(616)	(410)
Changes in non-cash work. cap. items	(212)	(74)	58	196	94	(38)	125	135
Net Free Cash Flow	(524)	(150)	(582)	(208)	(434)	(862)	(491)	(275)
Acquisitions & long-term investments	0	0	0	0	(250)	0	0	0
Short-term investments	0	0	0	0	0	0	0	0
Proceeds on asset sales	0	0	0	0	0	0	0	0
Amount to be financed	(524)	(150)	(582)	(208)	(684)	(862)	(491)	(275)
Net equity change	0	0	0	0	0	0	0	0
Net debt change	709	83	826	200	845	805	510	285
Other	12	13	24	25	37	15	9	7
Change in cash	197	(54)	268	17	198	(42)	28	17
Total debt	8,749	7,864	8,749	8,038	7,778	6,962	6,133	5,615
Cash and equivalents	425	118	425	228	172	0	16	0
Total debt in capital structure	57.3%	55.7%	57.3%	55.5%	56.5%	56.2%	54.5%	53.5%
Cash flow/Total debt	15.2%	16.5%	14.0%	15.1%	13.8%	13.4%	15.1%	17.9%
EBIT gross interest coverage (times)	2.90	2.89	2.76	2.75	2.42	2.23	2.71	2.88
Dividend payout ratio	83.0%	24.1%	60.0%	26.6%	4.8%	40.0%	52.0%	81.5%

2011 Summary

- Overall, Hydro One has maintained a strong financial profile, reflecting a stable balance sheet and reasonable credit metrics for the current ratings.
- Cash flow from operations remains strong, improving over time due to an increased rate base.
- Cash flow deficits persist primarily due to increased capex related to developing system reliability.
- Unlike other provincially and municipally owned distributors, Hydro One benefits from a flexible dividend program, unrestricted by an earnings threshold level.
- Key credit metrics including leverage, interest coverage and cash flow ratios have remained within the A (high) rating category.

2012 Outlook

- As of June 30, 2012, Hydro One expects capex to be $165 million below its 2012 budget of $1.8 billion ($1 billion on transmission and $800 million on distribution), primarily due to changes in the cost and timing of certain transmission projects as well as lower distribution development.
- The free cash flow deficit continued to be funded through debt. Key credit metrics are expected to remain reasonable for the current rating category with debt leverage maintained in the 55% to 60% range.
- However, debt issuance for the second half of the year is expected to be lower than initial expectations as a result of the lower capex.
- DBRS anticipates that free cash flow will continue to be affected by higher capital spending on the Company’s aging infrastructure. Going forward, Hydro One has budgeted $1.8 billion per annum for 2013 and 2014, with maintenance capex expected to be $950 million in 2013 and $1 billion in 2014.
- Cash flow from operations is expected to grow over the medium to long term, predominately driven by growth in the asset base.

Long-Term Debt Maturities and Bank Lines

- The Company's liquidity profile remains reasonable for the Company's current rating.

(CA$ millions - As at June 30, 2012)	Amount	Draw/LOCs	Available	Maturity
Cash & Cash Equivalents	425	-	425	-
Committed Revolving Facility	1,250	-	1,250	Jun-17
Ontario Floating Rate Notes	250	-	250	2014
Total	**1,925**	-	**1,925**	

- Hydro One has access to a $1.0 billion commercial paper program ($0 outstanding as of June 30, 2012) supported by an unused revolving facility ($1.25 billion) and a $250 million holding in Province of Ontario Floating-Rate Notes for liquidity.
- The Company had $23 million of bank debt as at June 30, 2012.
- Hydro One has a $3 billion base shelf prospectus, of which approximately $1,565 million is still available for issuance (to date), which expires in September 2013.
- Hydro One issued medium-term notes (MTN) of $300 million in January 2012, $125 million and $300 million in May 2012, $75 million in July 2012 and $235 million in August 2012.
- On August 15, 2012, Hydro One provided a notice for the redemption on September 4, 2012, of all the $600 million notes with a coupon of 5.77% due November 15, 2012.
- Hydro One's continued access to the capital markets through its MTN and commercial paper programs will be crucial over the next few years, given its infrastructure upgrade mandate. Despite the frequency of the Company's debt maturities in the medium term, DBRS anticipates that Hydro One will not have refinancing problems.

Long-term Debt Maturities

(CA$ millions - As at June 30, 2012)	2012	2013/2014	2015/2016	After 2016	Total
Principal Repayments	600	1,350	1,000	5,750	8,700
% of Total	6.9%	15.5%	11.5%	66.1%	100.0%

Hydro One Inc.

Report Date:
August 22, 2012

Hydro One Inc.

Balance Sheet	USGAAP	CGAAP	CGAAP		USGAAP	CGAAP	CGAAP
(CA$ millions)	**Jun. 30**	**Dec. 31**	**Dec. 31**		**Jun. 30**	**Dec. 31**	**Dec. 31**
Assets	**2012**	**2011**	**2010**	**Liabilities & Equity**	**2012**	**2011**	**2010**
Cash & equivalents	425	228	172	S.T. borrowings	23	39	0
Accounts receivable	958	961	911	Accounts payable	144	1,071	884
Inventories	23	25	21	Current portion L.T.D.	600	600	500
Prepaid expenses & other	146	63	85	Other current liab.	880	110	156
Total Current Assets	1,552	1,277	1,189	**Total Current Liab.**	1,647	1,820	1,540
Net fixed assets	15,269	14,903	14,061	Long-term debt	8,126	7,399	7,278
Future income tax assets	15	17	19	Deferred income taxes	896	758	693
Goodwill & intangibles	374	357	322	Provisions	2,211	1,290	1,278
Regulatory assets	2,138	1,064	1,013	Regulatory liabilities	222	635	540
Investments & others	312	750	718	L.T. Payables & Other L.T. liab.	36	12	12
				Preferred shares	323	323	323
				Common equity	6,199	6,131	5,658
Total Assets	19,660	18,368	17,322	**Total Liab. & SE**	19,660	18,368	17,322

	USGAAP	USGAAP	Mix	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP
Balance Sheet &	**6 mos. Jun. 30**		**12 mos. Jun. 30**	**For the year ended December 31**				
Liquidity & Capital Ratios	**2012**	**2011**	**2012**	**2011**	**2010**	**2009**	**2008**	**2007**
Current ratio	0.94	0.95	0.94	0.70	0.77	0.59	0.67	0.62
Total debt in capital structure	57.3%	55.7%	57.3%	55.5%	56.5%	56.2%	54.5%	53.5%
Cash flow/Total debt	15.2%	16.5%	14.0%	15.1%	13.8%	13.4%	15.1%	17.9%
(Cash flow-dividends)/Capex (times)	0.53	0.88	0.57	0.72	0.66	0.47	0.52	0.62
Dividend payout ratio	83.0%	24.1%	60.0%	26.6%	4.8%	40.0%	52.0%	81.5%
Coverage Ratios (times)								
EBIT gross interest coverage	2.90	2.89	2.76	2.75	2.42	2.23	2.71	2.88
EBITDA gross interest coverage	4.37	4.34	4.27	4.25	3.84	3.69	4.36	4.55
Fixed-charges coverage	2.89	2.88	2.76	2.75	2.41	2.24	2.73	2.86
Profitability Ratios								
EBITDA margin	63.0%	62.2%	62.0%	61.6%	59.3%	56.3%	60.1%	58.8%
EBIT margin	41.7%	41.5%	40.0%	39.9%	37.3%	34.1%	37.4%	37.2%
Profit margin	25.7%	24.5%	22.9%	22.2%	21.9%	19.4%	20.6%	16.5%
Return on equity	11.5%	11.4%	10.3%	10.2%	10.2%	8.9%	10.0%	8.2%
Return on capital	6.8%	6.8%	6.2%	6.3%	6.3%	5.7%	6.4%	5.6%

Hydro One Inc.

Report Date:
August 22, 2012

Ratings

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

Rating History

	Current	2011	2010	2009	2008
Commercial Paper	R-1 (middle)	R-1 (middle)	R-1 (middle)	R-1 (middle)	R-1 (middle)
Senior Unsecured Debentures	A (high)	A (high)	A (high)	A (high)	A (high)

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

MOODY'S
INVESTORS SERVICE

Credit Opinion: Hydro One Inc.

Global Credit Research - 23 Aug 2012

Toronto, Ontario, Canada

Ratings

Category	**Moody's Rating**
Outlook	Stable
Senior Unsecured -Dom Curr	A1
Commercial Paper	P-1

Contacts

Analyst	**Phone**
David Brandt/Toronto	416.214.3864
William L. Hess/New York City	212.553.3837

Key Indicators

[1]**Hydro One Inc.**

	[2]**LTM**	**2011**	**2010**	**2009**	**2008**
(CFO Pre-W/C + Interest) / Interest Expense	**3.5x**	**3.8x**	**3.7x**	**3.4x**	**3.7x**
(CFO Pre-W/C) / Debt	**12.0%**	**13.7%**	**14.1%**	**12.8%**	**14.3%**
(CFO Pre-W/C - Dividends) / Debt	**8.0%**	**12.0%**	**13.9%**	**10.4%**	**10.5%**
Debt / Book Capitalization	**62.0%**	**61.1%**	**59.2%**	**59.3%**	**59.5%**

[1] All ratios calculated in accordance with Moody's Regulated Electric and Gas Utilities Rating Methodology using Moody's standard adjustments. In addition, Moody's adjusts for one-time items [2] Last twelve months ended June 30, 2012

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

Opinion

Rating Drivers

Interrelationship with the Province of Ontario (Province, Aa2/Stable) and the influence of government policy/actions.

Large, low-risk regulated electric transmission and distribution (T&D) utility with no commodity price risk

Relatively supportive regulatory environment

Continued high capital expenditure could place pressure on financial metrics

Liquidity is adequate

Corporate Profile

Hydro One Inc. (HOI) began operations on 1 April 1999, pursuant to the Electricity Act, 1998, as a commercial corporation 100% owned by the Province of Ontario when the former Ontario Hydro was restructured into five entities: Ontario Power Generation Inc. (OPG), the Independent Electricity System Operator (IESO), Ontario Electricity Financial Corporation (OEFC), the Electricity Safety Authority and HOI. Virtually all of HOI's revenue and cash flow comes from its electricity transmission and distribution 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 a substantial portion of the province's electricity distribution assets. The Province does not explicitly guarantee HOI's debt obligations.

SUMMARY RATING RATIONALE

As a government related issuer, HOI's A1 rating reflects its baseline credit assessment (BCA) of 8 with three notch uplift attributable to high default dependence and high probability of extraordinary support from the Province of Ontario (Aa2). HOI's BCA is equivalent to a Baa1 rating as indicated by our Regulated Electric and Gas Utility rating methodology, reflecting lower risk and lack of commodity price risk inherent in the transmission and distribution sector, coupled with a relatively supportive regulatory environment. Despite consistently strong cash flow from operations, financial ratios have leveled off in recent quarters. HOI's investment in infrastructure has led to continuing high capital spending and a resultant increase in debt levels. HOI is not eligible to earn a cash return on construction work in progress so that cash generation lags the increases in debt associated with capital spending. Potential risk exists for HOI from government policy initiatives related to restructuring of Ontario's electricity sector and the re-launch of the Feed-in-Tariff (FIT) program, if the associated capital expenditures interfere with HOI's ability to refurbish its aging infrastructure or there is any unreasonable delay or limitations placed on HOI's ability to recover expenditures through its revenue requirement.

DETAILED RATING CONSIDERATIONS

INTERRELATIONSHIP WITH THE PROVINCE AND THE INFLUENCE OF GOVERNMENT POLICY/ACTIONS

In accordance with Moody's Government Related Issuer (GRI) rating methodology, HOI's A1 rating reflects the following:

Baseline Credit Assessment (BCA) of 8 (on a scale of 1 to 21, where 1 represents the equivalent risk of Aaa, 2/Aa1, 3/Aa2, 4/Aa3, 5/A1, and so on).

Aa2 local currency rating of the Province of Ontario.

High default dependence as a result of HOI's exposure to virtually all facets of the provincial economy and its operational and financial proximity to the government.

High probability of extraordinary support from the Province reflecting the strategic importance of HOI to the provincial economy and as an essential component of the government's energy policy; as well as the Province's history of maintaining a 60:40 deemed capital structure by modulating dividends payable each year.

HOI's BCA reflects the following:

LARGE, LOW-RISK, REGULATED ELECTRIC TRANSMISSION AND DISTRIBUTION UTILITY WITH NO COMMODITY PRICE RISK

We consider the transmission and distribution (T&D) segment to be a relatively lower risk part of the electric utility industry since it is typically not exposed to commodity price and volume risks or the operational, financial and environmental risks associated with electricity generation.

The OEB regulates both transmission and distribution. Transmission rates are set under a cost-of-service regime. Distribution rates are set applying an annual incentive regulation mechanism (IRM). For 2012, the allowed ROEs for the transmission and distribution segments are 9.42% and 9.66% respectively.

On May 28, 2012 Hydro One filed a revenue requirement and cost-of-service application for transmission rates seeking an increase in rates of less than 1% for 2013 and 9% in 2014. On the same date, HOI filed an IRM rate application for distribution rates in 2013 which would increase rates for customers by approximately 2.9%.

HOI's cash flow tends to be stable and predictable in relation to rate base growth 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. HOI has a degree of exposure to weather and the level of overall economic activity. This primarily affects the transmission segment, due to the fact that its transmission tariff is based on monthly peak transmission demand.

HOI's net income increased by 19% to $169 million in Q2/2012 versus the same quarter the year before. These results were mainly driven by higher average peak demand and a January 2012 rate increase attributable to a higher rate base. Rising debt levels, which, after Moody's adjustments, reached $9.7 billion at the end of the quarter, impacted leverage ratios as they increased proportionately more than cash flows from operations in part reflecting the lag between the expenditure and the addition to rate base. In addition to capital expenditures, financial metrics suffered from higher dividends as HOI applied a 60-65% payout level. Hydro One completed its 500kV Bruce-to-Milton Transmission Reinforcement Project seven months ahead of schedule in May 2012. The project will integrate over 3,000MW of refurbished nuclear and new wind generation to the Huron-Grey-Bruce area and represents one of the largest transmission expansions in Ontario's recent history. Consistent with previous years, Hydro One is tracking $165 million below its budgeted capital spending for 2012 due to changes in the timing and cost structure of particular transmission and distribution projects. In the course of the next three years we expect over $5 billion in capital expenditure to both improve aging infrastructure as well as to connect new energy to the grid. Major developments include the Advanced Distribution System (ADS) Project and the Midtown Electricity Infrastructure Renewal Project.

We believe that the incremental debt burden associated with continued high capital spending could place additional pressure on HOI's financial metrics. HOI is not eligible to earn a cash return on construction work in progress so cash flow increases lag the increases in debt associated with capital spending.

GOVERNMENT POLICIES AND INITIATIVES COULD POSE RISK IN THE LONG TERM

As part of the comprehensive review of Ontario's electricity sector, the Ministry of Energy on 18 April 2012 proposed to amalgamate the Ontario Power Authority (OPA) and the Independent Electricity System Operator (IESO) into one entity in order to achieve cost savings of about $25 million per annum. While not having a direct impact on HOI, it's an indication that reform proposals for the electricity sector are likely given the Province's budgetary pressures and the upward pressure on electricity rates due to the Province's energy policy which promotes relatively expensive renewable energy. The outcome could include rationalization of the distribution sector, with Hydro One being a potential acquirer of Local Distribution Companies (LDC) which would be expected to increase HOI's debt levels. Yet, of more concern from a rating perspective would be any restrictions placed on HOI's ability to recover expenditures related to the micro-FIT and FIT programs, as these programs are re-established in the Province's continued push to increase renewable power generation.

Ontario's electricity rates are amongst the highest for both residential and industrial customers in Canada. With growing rate-payer fatigue, rate increases might not be politically feasible, which in turn could impair HOI's ability to recover its cost or hinder its ability to make necessary investments to maintain critical infrastructure for the long term

Liquidity Profile

We believe that HOI's liquidity is adequate.

We expect HOI to have negative free cash flow of approximately $850 million for the twelve months ending June 30, 2013, which, coupled with scheduled debt maturities of $600 million for the period, would result in a net funding requirement of approximately $1.45 billion. Given availability of about $1.125 billion under HOI's $1.25 billion committed credit facility that matures in 2017, the $250 million Province of Ontario floating rate note (FRN) held by HOI and $425 million cash on hand, HOI had liquidity of about $1.8 billion at June 30, 2012. Our standard liquidity stress scenario assumes that an issuer loses access to new capital, other than credit available under its committed credit facilities, for a period of 12 months. On this basis, HOI has an estimated liquidity surplus of approximately $350 million.

Hydro One has demonstrated its ability to readily access capital markets. With approximately $1 billion of debt raised year-to-date, including $310 million of 50 year debt in July and August, we expect further issuance of approximately $200 million over the remainder of the year.

Rating Outlook

HOI's rating outlook is stable.

What Could Change the Rating - Up

Moody's considers an upward revision in HOI's A1 rating to be unlikely in the near term. However, the company's senior unsecured rating could be positively impacted by a two notch improvement in its BCA to 6, or by a change in facts and circumstances that causes us to believe that the probability of extraordinary support should be higher than we currently believe it is. An improvement in HOI's BCA to 6 would require both a sustainable improvement in financial ratios (such as CFO pre-WC to Interest exceeding 4.5x, CFO pre-WC to Debt exceeding 22% and CFO pre-WC less Dividends to Debt exceeding 17%) and a more favourable assessment of HOI's regulatory and cost recovery environment.

What Could Change the Rating - Down

HOI's A1 senior unsecured rating could be negatively impacted by one or more of the following:

A reduction in both the Province's rating and HOI's BCA, or

A material reduction in the perceived probability of extraordinary support due to changes in the ownership, governance or management structures or other factors.

A one notch reduction in HOI's BCA to 9 could follow a sustained weakening of cash flow metrics such as CFO pre-WC to Interest coverage below 3.3x, CFO pre-WC to Debt below 13% and/or CFO pre-WC less Dividends to Debt below 9% combined with a deterioration in HOI's regulated ability to recover its costs and earn an appropriate return.

Rating Factors

Hydro One Inc.

Regulated Electric and Gas Utilities Industry [1]	[2]**Current**		[3]**Moody's 12-18 month Forward View As of August 2012**	
Factor 1: Regulatory Framework (25%)	**Measure**	**Score**	**Measure**	**Score**
a) Regulatory Framework		A		A
Factor 2: Ability To Recover Costs And Earn Returns (25%)				
a) Ability To Recover Costs And Earn Returns		A		A
Factor 3: Diversification (10%)				
a) Market Position (10%)		Baa		Baa
b) Generation and Fuel Diversity (0%)				
Factor 4: Fin. Strength, Liquidity And Key Fin. Metrics (40%)				
a) Liquidity (10%)		Baa		Baa
b) CFO pre-WC + Interest/ Interest (3 Year Avg) (7.5%)	3.7x	Baa	3.6-3.7x	Baa
c) CFO pre-WC / Debt (3 Year Avg) (7.5%)	13.7%	Baa	13%-14%	Baa
d) CFO pre-WC - Dividends / Debt (3 Year Avg) (7.5%)	11.7%	Baa	9%-10%	Baa
e) Debt/Capitalization (3 Year Avg) (7.5%)	59.7%	Ba	62%-64%	Ba
Rating:				
a) Indicated Baseline Credit Assessment from Methodology Grid		8 (Baa1)		8 (Baa1)
a) Actual Baseline Credit Assessment from Methodology Grid				8 (Baa1)

Source: Moody's Financial Metrics.

[1] All ratios calculated in accordance with Moody's Regulated Electric and Gas Utilities Rating Methodology using Moody's standard adjustments. In addition, Moody's adjusts for one-time items [2] Based on financial data as of 06/30/2012(L); Source: Moody's Financial Metrics [3] This represents Moody's forward view; not the view of the issuer; and unless noted in the text, does not incorporate significant acquisitions and divestitures.

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PROCEDURAL ORDERS – CORRESPONDENCE - NOTICES

Attachment 1: Notice of Application and Hearing

Attachment 2: Procedural Order No. 1

Ontario Energy Board **Commission de l'énergie de l'Ontario**

Ontario

EB-2012-0136

NOTICE OF APPLICATION AND HEARING FOR AN ELECTRICITY DISTRIBUTION RATE CHANGE

Hydro One Networks Inc.

Hydro One Networks Inc. ("Hydro One") has applied to the Ontario Energy Board for permission to increase its delivery charges beginning January 1, 2013. The application was filed on June 15, 2012 under section 78 of the *Ontario Energy Board Act*, *1998*, S.O. 1998, c.15 (Schedule B), under the Board's guidelines for 3rd Generation Incentive Regulation Mechanism which provides for a mechanistic and formulaic adjustment to distribution rates between cost-of-service applications. Hydro One's application also includes a request to establish a rate rider to recover incremental capital additions of $645 million using the Board's Incremental Capital Module, and a request to adjust rates based on the results of a customer Density Study completed in 2011.

Delivery charges are one of four regular items on Residential and General Service customers' electric bills and vary depending on the amount of electricity consumed. If the application is approved as applied for, a representative monthly bill for a Residential customer who consumes 800 kWh per month would increase by about $2.95. A representative monthly bill for a General Service customer consuming 2,000 kWh per month and having a monthly demand of less than 50 kW would increase by about $6.19. The proposed changes to the Delivery charges are separate from other potential changes to the electricity bills, which are not affected by this application.

On a more specific basis, due to the implementation of the density study findings and the finalization of Hydro One's rate harmonization plan for General Service customers in Quinte West and Smiths Falls, Hydro One indicates that if the application is approved as filed, the 2013 monthly bill impact will range from a decrease of 2.3% or $3.05 to an increase of 4.1% or $6.22 for Residential customers consuming 800 kWh per month.

For General Service energy-billed customers consuming 2,000 kWh per month the monthly bill impact will range from a decrease of 5.0% or $14.77 to an increase of 3.8% or $13.06.

For additional information on billing items visit the Consumer page of the Board's website at http://www.ontarioenergyboard.ca.

The Board has assigned the application File No. EB-2012-0136. The Board's decision on this application may have an effect on all of Hydro One's customers.

The Board will proceed with this application by way of an oral hearing.

How to see Hydro One's Application

To see a copy of the application, go to the Consumer page of the Board's website and enter the case number EB-2012-0136 in the "Find an Application" box. A copy can also be seen at the Board's office and on Hydro One's website at www.HydroOne.com and at the following Hydro One Networks Inc. offices:

Head Office, 8th Floor, South Tower, 483 Bay Street, Toronto
Barrie Field Business Centre, 45 Sarjeant Drive, Barrie
Peterborough Field Business Centre, 913 Crawford Drive, Peterborough
Sudbury Field Business Centre, 957 Falconbridge Road, Sudbury
Merivale Service Centre, 31 Woodfield Drive, Ottawa
Dundas Field Business Centre, 40 Olympic Drive, Dundas
Beachville Field Business Centre, 56 Embro Street, Beachville
Thunder Bay Field Business Centre, 255 Burwood Road, Thunder Bay

How to Participate

Comment

If you wish to give your opinion on the proceeding to the Board Members hearing the application, you are invited to send a written letter of comment to the Board no later than **30 days** after the publication or service date of this notice. A complete copy of your letter of comment, including your name, contact information, and the content of the letter, will be provided to the applicant and the Hearing Panel.

Observe
If you do not wish to actively participate in the proceeding but you do wish to receive documents issued by the Board, you may request observer status. Your written request must be received by the Board no later than **10 days** from the publication or service date of this notice.

Personal Information in Letters of Comment and Observer Requests
All letters of comment or letters requesting observer status will be placed on the public record, which means that the letters can be seen at the Board's office and will be available on the Board's website. Before placing the letters on the public record, the Board will remove any personal (i.e. not business) contact information from the letters (i.e. the address, fax number, phone number, and e-mail address of the individual). However, the name of the individual and the content of the letter will become part of the public record. Please address your letter to the Board Secretary at the address below, and reference file number **EB-2012-0136** at the top of your letter.

Intervene
If you wish to actively participate in the proceeding (e.g., submit questions, file argument), you may request intervenor status from the Board no later than **10 days** after the publication or service date of this notice. Instructions for requesting intervenor status are available on the Board's website at www.ontarioenergyboard.ca/participate. Everything an intervenor files with the Board, including the intervenor's name and contact information, will be placed on the public record, which can be seen at the Board's office and will be available on the Board's website.

If you do not have internet access, please call 1-888-632-2727 to receive information about this proceeding and how to participate.

IMPORTANT
IF YOU DO NOT PARTICIPATE IN THE HEARING IN ACCORDANCE WITH THIS NOTICE, THE BOARD MAY PROCEED WITHOUT YOUR PARTICIPATION AND YOU WILL NOT BE ENTITLED TO ANY FURTHER NOTICE IN THE PROCEEDING.

Addresses

The Board:

Post:
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Attention: Board Secretary

Filings:
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E-mail: boardsec@ontarioenergyboard.ca

Tel: 1-888-632-6273 (toll free)
Fax: 416-440-7656

The Applicant:

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Regulatory Coordinator – Regulatory Affairs

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Fax: 416-594-9100

DATED at Toronto**, July 6, 2012**

ONTARIO ENERGY BOARD

Original Signed By

Kirsten Walli
Board Secretary

Ontario Energy Board | **Commission de l'énergie de l'Ontario**

Ontario

EB-2012-0136

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

AND IN THE MATTER OF a review of an application filed by Hydro One Networks Inc. for an order or orders approving just and reasonable rates and other charges for electricity distribution effective January 1, 2013.

Decision on Intervenor Status, Cost Award Eligibility and PROCEDURAL ORDER NO. 1
August 9, 2012

Hydro One Networks Inc. (Hydro One) filed an application, dated June 15, 2012, with the Ontario Energy Board under section 78 of the *Ontario Energy Board Act,* 1998, c.15, Schedule B, and the Board's Incentive Regulation Mechanism (IRM) framework seeking approval for changes to the rates that Hydro One charges for electricity distribution, to be effective January 1, 2013. Hydro One has also applied for an adjustment to the rates it charges to accomodate proposed spending on projects contained in an Incremental Capital Module (ICM). The Board has assigned the application File Number EB-2012-0136.

The Board issued a Notice of Application and Hearing dated July 6, 2012. The Board received 15 requests for intervenor status. The Board grants the requests for intervenor status for all parties who requested it.

A list of the intervenors is attached as Appendix A.

The Balsam Lake Coalition (BLC), Ontario Federation of Agriculture (OFA), Building Owners and Managers Association, Greater Toronto (BOMA), Ecology Ottawa, Canadian Manufacturers and Exporters (CME), Energy Probe, School Energy Coalition (SEC), Vulnerable Energy Consumers Coalition (VECC), and the Association of Major Power Consumers (AMPCO) also applied for cost award eligibility.

In making its findings on the requests for cost award eligibility the Board has considered the nature and scope of this application. Both BLC and Ecology Ottawa have cited interests that will not be considered in this application.

BLC's interest relates to the classification of customers and the manner in which costs are allocated. These matters are not dealt with in IRM hearings unless adjustments to cost allocations had been predetermined in a previous cost of service hearing where these matters are open to full discovery and examination.

Ecology Ottawa's cited specific interest pertains to obtaining clean energy sources. The Board will not be considering matters related to clean energy sources in this hearing. In addition, it would appear that most of Ecology Ottawa's members reside within the area of Hydro Ottawa, not Hydro One.

BOMA indicates that its membership is in the Greater Toronto area and therefore not directly subject to the rates to be determined in this proceeding.

In consideration of the scope of this hearing the Board finds that BLC, Ecology Ottawa and BOMA are not eligible for an award of costs. The Board finds that OFA, CME, Energy Probe, SEC, VECC and AMPCO are eligible for an award of costs.

The Board expects all cost eligible intervenors to cooperate to the maximum extent possible and avoid duplication of effort wherever possible.

As indicated in the Notice of Application, the Board intends to proceed by way of an oral hearing preceded by written interrogatories and responses. Based on the Board's experience with oral proceedings, the Board expects that it may be able to render a decision on or about February 7, 2013.

With regard to a draft issues list for this proceeding, the Board has reviewed its previous Hydro One Distribution Rates Decision (EB-2009-0096) with regard to its findings on the implementation of the Density Study submitted by Hydro One. The Board finds that the implementation of the Density Study findings are not an appropriate issue in an IRM application and will not include this issue on the Issues List for this proceeding. Cost allocation and rate design issues are best dealt with in a cost of service application, which Hydro One has indicated it will file in 2013.

The Board has attached a draft Issues List as Appendix B. Intervenors and Hydro One may make submissions on the draft list and propose changes for the Board's consideration. In proposing additional issues, parties should provide justification and give consideration as to whether the item is already included under one of the proposed issues. Similarly, parties proposing to remove or limit the scope of an issue on the draft list should provide justification. After reviewing these submissions, the Board will issue a final issues list. Only matters that are on the final issues list will be considered in this proceeding.

The Board has not provided for an Issues Day, but may adjust the schedule if it is determined that one is required. The Board is also requiring intervenors to indicate whether they intend to file evidence in this proceeding as soon as possible. In the event that intervenor evidence is filed the schedule will be adjusted accordingly.

Hydro One has filed a document, entitled Investigation into Premature Degradation of CCA-Treated Wood Poles and Recommendations to Ensure Their Reliable Performance (the Wood Pole Study). A redacted version of the document is filed as Exhibit B/Tab2/Schedule3/Attachment1and an unredacted copy has also been filed with the Board. Hydro One has requested confidential treatment of the unredacted document. The Board has reviewed the redactions and confirms that the redactions are limited to the company names. The Board will invite submissions on whether it is necessary to have the unredacted version of the Wood Pole Study on the record of this proceeding (and if so, whether it should be confidential), or whether it is sufficient to have the redacted version on the record.

The Board considers it necessary to make provision for the following matters related to this proceeding. Although the date for the oral hearing is not currently specified, it is expected that the oral hearing will take place in mid-October, 2012. The Board will issue further procedural orders from time to time.

THE BOARD ORDERS THAT:

1. Hydro One and intervenors may make submissions on the draft issues list (attached as Appendix B) and the request for confidentiality and shall file any submissions with the Board and deliver them to all parties no later than Thursday, August 16, 2012.

2. Hydro One may respond to the submissions of intervenors, and intervenors may respond to the submissions of Hydro One or other intervenors by filing those responses with the Board and delivering them to all parties no later than Tuesday, August 21, 2012.

3. Board staff seeking information and material that is in addition to the Hydro One's pre-filed evidence, and that is relevant to the hearing, shall request the same by written interrogatories filed with the Board and delivered to all parties on or before Monday, August 27, 2012.

4. Intervenors seeking information and material that is in addition to the Hydro One's evidence, and that is relevant to the hearing, shall request the same by written interrogatories filed with the Board and delivered to all parties on or before Thursday, August 30, 2012.

5. Any intervenor that intends to file evidence shall notify the Board of its intention, no later than Thursday, August 30, 2012 and shall copy all parties.

6. Responses by the Applicant to interrogatories shall be filed with the Board and delivered to all parties on or before Friday, September 14, 2012.

7. Board staff and intervenors who wish to file evidence shall do so, on or before Tuesday, September 25, 2012 and deliver it to all parties.

8. Any party seeking information and material that is in addition to the intervenor or Board staff evidence, and that is relevant to any matter at issue in the hearing, shall request the same by written interrogatories filed with the Board and delivered to all parties on or before Friday, October 5, 2012.

9. Responses to the interrogatories on intervenor or Board staff evidence shall be filed with the Board and delivered to all parties on or before Thursday, October 11, 2012.

All filings to the Board must quote file number EB-2012-0136, be made through the Board's web portal at https://www.pes.ontarioenergyboard.ca/eservice/, and consist of two paper copies and one electronic copy in searchable / unrestricted PDF format. Filings must clearly state the sender's name, postal address and telephone number, fax number and e-mail address. Please use the document naming conventions and document submission standards outlined in the RESS Document Guideline found at www.ontarioenergyboard.ca. If the web portal is not available you may email your document to the address below. Those who do not have internet access are required to submit all filings on a CD or diskette in PDF format, along with two paper copies. Those who do not have computer access are required to file 7 paper copies.

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ISSUED at Toronto, August 10, 2012

ONTARIO ENERGY BOARD

Original Signed By

Kirsten Walli
Board Secretary

APPENDIX A

HYDRO ONE NETWORKS INC
DISTRIBUTION RATE HEARING
FOR 2013 RATES

EB-2012-0136

APPLICANT & LIST OF INTERVENORS

Appendix A
Hydro One Networks Inc.
Distribution Rate Hearing
2013 Rates

EB-2012-0136

Applicant and List of Intervenors

Hydro One Networks Inc.
EB-2012-0136

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August-10-12

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APPENDIX B

HYDRO ONE NETWORKS INC
DISTRIBUTION RATE HEARING
FOR 2013 RATES

EB-2012-0136

Draft
ISSUES LIST

Appendix B
Hydro One Networks Inc.
Distribution Rate Hearing
2013 Rates

EB-2012-0136

DRAFT ISSUES LIST

1. IRM Methodology

1.1 Has Hydro One appropriately applied the IRM mechanism as specified by the Board?

2. Incremental Capital Module/Rate Rider

2.1 Should the proposed capital projects be approved for ICM treatment?

2.2 Is the proposed rate implementation for projects approved under the ICM, if any, appropriate?

3. Other Rate Riders and Adders

3.1 Is Hydro One's proposed disposition of Group 1 Deferral and Variance Accounts appropriate?

3.2 Is Hydro One's proposed rate rider to share the impact of the income tax decrease with customers appropriate?

3.3 Is Hydro One's proposed Smart Grid rate adder appropriate?

3.4 Are the proposed adjustments to the Retail Transmission Service rates appropriate?

4. Final Step of Harmonization Plan

4.1 Is Hydro One's proposal to implement the final adjustments of the Harmonization Plan in accordance with the Board's directions?

PROPOSED INCREMENTAL CAPITAL MODULE

Hydro One is requesting recovery for required capital under the Incremental Capital Module ("ICM"). Hydro One requires incremental revenue of $26 million in 2013 associated with required in service capital additions. Hydro One requests that a 2013 rate rider be established to recover this revenue requirement. The resulting average increase for customers, as a result of this rider, is approximately 2.3%. Hydro One will demonstrate that it has passed the Threshold Test that allows access to the ICM. Hydro One will also provide information on some of the issues related to the ICM and the approach that Hydro One has taken with this application. This approach is consistent with Hydro One's submission in the Renewed Regulatory Framework proceeding (EB-2010-0377, EB-2011-0043 and EB-2011-0004) filed with the Board on April 20, 2012.

Threshold Test:

The Board has provided a formula for the Threshold Value which determines whether or not a distributor is able to access the ICM. The Board's formula is as follows:

Threshold Value = 1 + (RB/d) * (g + PCI * (1 + g)) + 20%

Where:

RB = rate base included in base rates ($4,987 million)

d = depreciation expense included in base rates ($284 million)

g = distribution revenue change from load growth (-1.04%)

PCI = price cap index (0.88%)

The values for "RB" and "d" are the Board-approved amounts from Hydro One's EB-2009-0096 proceeding. The negative growth factor of 1.04% is calculated using the Board's approach. It is calculated as the percentage difference between Hydro One's 2011 approved revenue of $1,149 million and the 2010 revenue at 2011 rates of $1,161 million. The PCI of 0.88% has been specified by the Board for use in 2012 IRM applications and is calculated by subtracting the productivity factor of 0.72% and the stretch factor of 0.40% from the price escalator of 2.00% (note that the Board specified 2013 PCI should be issued and will be utilized when the Decision in this proceeding is put into effect). The resulting Threshold Value of 117% is applied to the depreciation expense included in base rates of $284 million to determine Hydro One's Capital Threshold of $332 million.

The Capital Threshold for Hydro One is $332 million while the in service capital requirement for 2013 is $644 million. Hydro One has passed the Threshold Test and is therefore able to access the ICM for its 2013 IRM application.

Types of Investment:

Hydro One has defined three categories of capital investment that make up the $644 million in required in-service additions: "Typical" capital spending; "Escalated Issue" capital spending; and "Non-typical" capital spending.

The first category is Typical capital spending which includes historically approved levels of sustainment, development and shared services and other spending. Sustainment spending includes categories such as wood pole replacements, transformer replacements, investments in distributing and regulating stations, repairing storm damage and the replacement of meters. Development spending includes categories such as new load connections, and upgrades and system capability reinforcement. Shared services and other spending includes information technology, fleet, and work and office equipment. Typical capital spending is reviewed in detail at Cost of Service ("COS") rebasing hearings and does not require detailed further review during the period of the IRM.

The second category is Escalated Issues capital spending. This category covers spending on typical categories but at a substantial increase over historically approved levels. The higher level of capital spending is required to address an identified escalated issue. For example, a distributor may require a substantial increase over historically approved levels to address a quality issue related to certain poles. This quality issue may relate to asset age or a manufacturer issue. Escalated Issue capital spending requires a more detailed review when introduced during the period of an IRM. This review covers the need and timing of the proposed level of spending. The Escalated Issue category of capital spending is further described in Exhibit B, Tab 2, Schedules 1 to 3.

The third category covers Non-typical capital spending for 2013. This category covers the cost to replace Hydro One's Customer Information System ("CIS"). Non-typical capital spending requires a full review by the Board when introduced during the IRM period. The Non-typical category of capital spending is further described in Exhibit B, Tab 3, Schedule 1.

Capital Recovery under ICM:

The current ICM provides a mechanism for recovering Escalated Issue and Non-typical capital spending during an IRM period. There is also a requirement to recover Typical capital spending, in excess of approved depreciation, during the period of an IRM. The Board's examination under the Renewed Regulatory Framework recognizes that one of the major challenges facing the sector today, and the most significant driver of costs, is the scale of capital spending expected over the next number of years to modernize the system and to provide for new demand. Table 1 calculates the amount of capital that Hydro One needs to recover through the ICM for Typical capital.

Table 1

Incremental Capital Required for Typical Capital Spending ($millions)

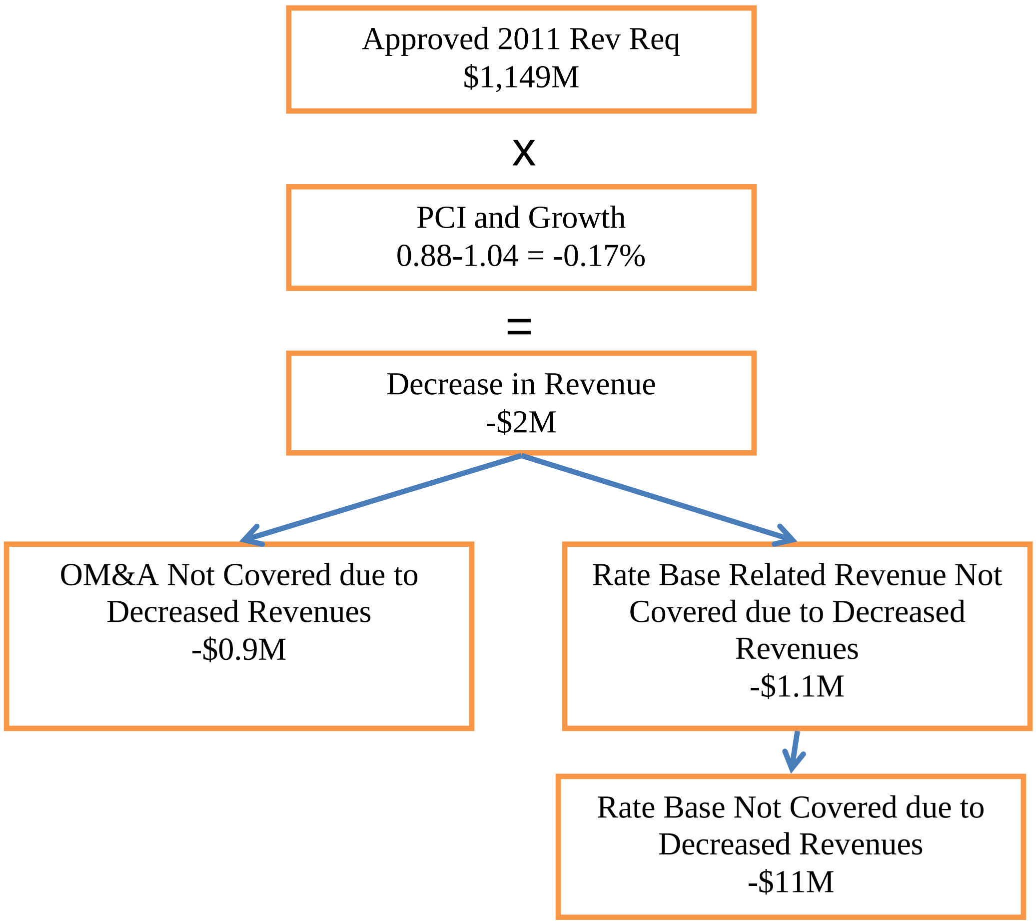
Line #		**COS 2011**	**IRM 2013**
1	Typical capital spending	$438	$414
2	Rate base impact of in-service capital		$414
3	Less rate base funded by depreciation		-$283
4	Add rate base no longer funded resulting from decrease in revenue		$11
5	Growth in rate base for Typical capital (line 2 + line 3 + line 4)		$142
6	Revenue required due to growth in rate base for Typical capital		$14

Line number 1 in Table 1 provides Hydro One's typical capital spending for 2013 of $414 million. To determine the growth in rate base for typical capital of $142 million one must deduct the approved rate base funded by the approved depreciation amount of $283 million and add back the $11 million in rate base that is no longer funded as a result of decreased revenues. The approved rate base funded by depreciation can be found in Hydro One's Board approved rate order for its EB-2009-0096 proceeding. Line 6 provides the revenue required due to growth in rate base for Typical capital of $14 million. The revenue required covers depreciation, cost of capital and taxes.

Figure 1 provides the derivation of the rate base which is no longer funded as a result of decreased revenues.

Figure 1

Derivation of Rate Base No Longer Funded due to Decreased Revenues



To determine the Rate Base adjustment required as a result of decreased revenues one must start with the 2011 approved revenue requirement of $1,149 million and apply the PCI plus growth percentage. The PCI of 0.88% plus the negative growth of 1.04% [1]results in negative 0.17% to be applied to the approved revenue requirement. The resulting decrease in revenue of $2 million is apportioned to OM&A and Rate Base based on the percentage of OM&A and rate base related revenues that make up the approved revenue requirement. This results in rate base related revenue requirement not covered

[1] The supporting calculations for PCI and negative growth can be found on page 1 of this Exhibit.

due to decreased revenues of $1.1 million. This in turn results in rate base not covered due to decreased revenues of $11 million. As a result of the decrease in revenues, $11 million in rate base is no longer recovered in approved rates.

ICM Issues:

It is critical that Hydro One recover Typical, Escalated Issue and Non-typical capital spending during the period of an IRM. Hydro One is not in a position, due to credit rating issues, to invest in rate base for which there is no cost recovery. Any negative impact to Hydro One's credit rating would result in borrowing challenges and increased borrowing costs for our customers. In order to avoid any negative credit rating impacts, Hydro One must maintain its earnings metrics including rate of return. Adding to this pressure, Hydro One was recently downgraded by Moody's by one notch. Also, Standard and Poors has revised Hydro One's outlook from stable to negative. These reports are filed at Exhibit A, Tab 6, Schedule 1, Attachments 1 & 2.

An unintended outcome of not being in a position to invest in rate base for which there is no return is lower reliability as Hydro One would have less ability to replace or refurbish assets prior to breakdown. A common industry term for this is the "harvesting" of assets. Another unintended outcome is not replacing or refurbishing assets when it is economically beneficial to do so. Planning for replacement and refurbishment and executing the plan is less costly than simply replacing or refurbishing assets when they break. The harvesting of assets would certainly result in increased contract and employee labour costs as Hydro One would be unable to levelize work based on the most efficient use of resources.

Finally, recovery of Typical, Escalated Issue and Non-typical capital spending during the period of an IRM avoids step increases in rates at COS rebasing hearings. This is particularly important given the capital intensive nature of the electricity distribution business and the pressing need for Hydro One to renew and modernize its system to meet the needs of its customers.

Hydro One's Approach:

In this application, Hydro One requests the approval of a rate rider based on the full capital program for in-service additions in 2013 based on a review of forecast changes to rate base.

Hydro One will apply the 2013 Board approved cost of capital in determining the revenue requirement when it is available, as outlined in Exhibit B, Tab 1, Schedule 2. Hydro One believes that this is appropriate because the new investments should earn returns that are consistent with the anticipated returns during the period of the investment. This treatment results in a lower return than would be realized if Hydro One applied the 2011 Board approved cost of capital as specified at page 8 in Chapter 3 of the Filing Requirements for Transmission and Distribution Applications dated June 28, 2012.

The extent of the capital investment review is determined by the nature of the investments that are driving the change in rate base. Typical capital spending is reviewed in detail at COS rebasing hearings and should not require detailed review during the period of the IRM. The Typical category is very familiar to stakeholders. The general level and type of Typical capital spending continues during the IRM period. This is similar to the treatment of OM&A costs during an IRM period.

For Hydro One, Typical capital includes the capital spending approved in the most recent COS application (i.e. net of any OEB directed reductions) less all capital spending associated with renewable generation and smart grid investments as spending in these areas is recovered through rate riders and deferral accounts. Table 2 shows the Typical capital spending for the historic, base and IRM years.

Table 2
Summary of Typical Capital
($ Million)

	Historic			Base Year	IRM Year
	2008	2009	2010	2011	2013
TOTAL	435.3	455.5	430.5	437.6	451.9

The amount of revenue requirement that a utility requires to recover its capital investments in a particular year results from the in-service capital additions in the year, not the capital expenditures in the year as some projects require several years before they are completed. The in-service capital additions in the year are added to rate base and therefore are included for recovery in rates. The in-service capital additions in 2013 for the Typical capital are $414 million.

The Escalated Issue category includes increased spending on stations, pole replacements and the capital contribution for a transmission station to address pressing issues. Hydro One has filed three years of historic investment information to establish the typical spending pattern for these types of investments. Detailed age and asset condition information has been provided to defend Hydro One's spending to address the Escalated Issues. The evidence is detailed and is consistent with the high quality of evidence that has been filed in previous COS filings for these types of program investments.

Finally, the Non-typical category includes spending to replace Hydro One's current Customer Information System. Hydro One has provided detailed evidence that is consistent with the high quality evidence that has been filed in previous COS filings for this type of project investment.

In summary, Hydro One requests recovery of Typical, Escalated Issue and Non-typical in-service capital additions as outlined in the following table.

Table 3

Typical, Escalated Issue and Non-Typical Investment Recovery

Line #	(All $ in millions)	2013 Capital	Associated ICM Revenue	% Distribution Rate Impact
1	Typical	$414	$14	1.2%
2	Escalated Issue	$75	$6	0.5%
3	Non-typical	$155	$7	0.6%
4	Total in service additions	$644	$26	2.3%

The revenue increase required for each category is provided in the second last column and the associated rate impact for a typical customer is provided in the last column. The derivation of the required revenue associated with Typical in service capital is $14 million and the supporting calculation is contained in Table 1 of Exhibit B, Tab 1, Schedule 2. The derivation of the required revenue associated with Escalated Issue and Non-typical in service capital is also provided in the same exhibit.

In summary, Hydro One has met the Threshold Test for the ICM and is requesting an associated increase in revenue requirement of $26 million to recover required expenditures on Typical, Escalated Issue and Non-typical capital. Hydro One proposes that this required increase in revenues be recovered through a 2013 approved rate rider as detailed in Exhibit E1, Tab 2, Schedule 1.

CALCULATION OF INCREMENTAL CAPITAL MODULE REVENUE REQUIREMENT

1.0 OVERVIEW

In calculating the revenue requirement for the proposed ICM introduced in Exhibit B, Tab 1, Schedule 1, the methodology applied is generally consistent with Board requirements as outlined in Chapter 3 of "the Filing Requirements for Transmission and Distribution Applications", dated June 28, 2012. The attached Table 1 provides the calculations made to determine the revenue requirement for Typical, Escalated Issue and Non-typical capital; the latter two categories are discussed in detail in Exhibit B, Tabs 2 and 3 respectively. An overview of the methodology and parameters applied to determine the revenue requirement follows below.

Hydro One Distribution is proposing to allocate the revenue requirement associated with the incremental capital expenditures eligible for cost recovery on the basis of distribution revenue. Hydro One Distribution proposes to recover this amount by means of a variable rate rider, as outlined in Exhibit E1, Tab 2, Schedule 1, Attachment 1, which will remain in effect until Hydro One Distribution's next cost of service application.

2.0 DISCUSSION

Full Year Rule for In Service Additions

The revenue requirement calculations are consistent with Board direction that the half-year rule for in-service additions not be applied. The Board determined that the half-year rule should not apply so as not build a deficiency for the subsequent years of the IRM plan term. Consequently all calculations including depreciation, return on capital as well as the CCA claim in determining the income tax are based on the full year in-service addition assumption.

However one exception has been made in the case of the Non-Typical capital CIS project. The CCA claim used in the tax calculation is based upon the half-year rule in order to smooth this impact over the 2013 and 2014 years. This results in rate smoothing as well as process efficiency. Specifically, the resulting $6.8 million of incremental revenue requirement results in a 0.6% rate increase in 2013. Alternatively, if the full CCA claim for CIS were factored in in 2013, rather than the half-year rule, the incremental revenue requirement which would result would be -$19.8 million or a rate decrease of 1.7%. In this case, in order to recover a fair and equitable return on this necessary investment, Hydro One would re-submit the project in the 2014 IRM test year, seeking full recovery of the required $32.28 million revenue requirement in that year, resulting in an incremental 4.6% rate increase. Calculation details of this alternative approach are provided in Table 2. Hydro One believes that its recommended approach of applying the half year rule on the CCA calculation benefits the rate payer through rate smoothing (a single incremental rate increase of 0.6% in 2013; versus a rate decrease of 1.7% in 2013 followed by an incremental 4.6% rate increase in 2014); and benefits the Board through the process efficiency of having to consider the CIS project in only one IRM proceeding rather than two.

Depreciation and CCA

Appropriate depreciation rates and CCA rates were used for each program or project. For Typical capital, a depreciation rate of 3.5% and CCA rate of 8% was applied. In the case of the Escalated Issue projects/ programs, depreciation rates of about 2% and CCA rates of 8% per year were utilized. In the case of the Non-Typical capital CIS project, the appropriate depreciation rate is 10.5% whereas the CCA rate is 100%.

Capital Structure

Hydro One Distribution’s deemed capital structure for rate making purposes is 60% debt and 40% common equity. This capital structure was approved by the Board as part of its

Decision With Reasons in EB-2009-0096. This is consistent with the Board's report on the cost of capital: see the Report of the Board on the Cost of Capital for Ontario's Regulated Utilities dated December 11, 2009 (EB-2009-0084). The 60% debt component is comprised of 4% deemed short term debt and 56% long term debt.

Cost of Capital Parameters

In terms of the cost of capital parameters applied, consistent with Exhibit B, Tab 1, Schedule 1, these were derived on a more recent consensus forecast than the Board approved rates for 2011 in EB-2009-0096, resulting in a lower cost of capital.

Specifically, a return on equity rate of 9.16% was applied. This is based on the Board's formulaic approach in the Report of the Board (EB-2009-0084). The return on equity calculation is based on the February 2012 Consensus Forecast (12 month out), as well as Bank of Canada data and the change in the spread of A-rated Utility Bond Yields during February. Hydro One assumes that the return on equity for 2013 will be updated in accordance with the December 11, 2009 Cost of Capital Report, upon the final decision in this case. For rates effective January 1, 2013, the Board would determine the ROE for Hydro One Distribution based on the September 2012 Consensus Forecasts and Bank of Canada data which would be available in October 2012.

The deemed short-term rate assumed is 2.01% for 2013 using the February 2012 Global Insight Forecast plus a spread of 91 bps, which is based on the spread contained in the Cost of Capital Parameter Updates for 2012 Cost of Service Applications for Rates Effective January 1, 2012, dated November 10, 2011. Hydro One assumes that the deemed short term debt rate for 2013 will be updated in accordance with the December 11, 2009 Cost of Capital Report, upon the final decision in this case. Specifically, for rates effective January 1, 2013, the Board would determine the deemed short term debt rate based on the September 2012 Bank of Canada data which would be available in October 2012 plus the average spread obtained by Board Staff in 2012.

The long term debt rate is calculated to be 4.94% for 2013. The long term debt rate is calculated as the weighted average rate on embedded debt, new debt and forecast debt planned to be issued in 2012, and 2013. As discussed in this exhibit, forecast interest rates will be updated consistent with the methodology used for the return on common equity and deemed short term interest rate.

Table 1
CALCULATION OF 2013 ICM REVENUE REQUIREMENT

Project / Program		Typical Capital	Escalated Issue Capital								Non-Typical Capital	Total
		Miscellaneous		**Commerce Way TS Capital Contribution**		**Distributing & Regulating Stations**		**Wood Pole Replacement**	**Subtotal Escalated Issue Capital**		**CIS**	
In Service Addition		142		9.2		42.63		22.86	74.69		155.40	372.09
Average Rate Base (no half year)		139.52		9.11		42.21		22.64	73.96		147.22	360.69
Depreciation	3.50%	4.97	2.0%	0.19	2.0%	0.84	1.9%	0.44	1.47	10.5%	16.36	22.80
Return on Debt (blended)		3.97		0.26		1.20		0.64	2.11		4.19	10.28
Return on Equity		5.11		0.33		1.55		0.83	2.71		5.39	13.22
Tax		(0.36)		(0.07)		(0.35)		(0.19)	(0.61)		(19.15)	(20.12)
Total Incremental Revenue Requirement		***13.70***		***0.71***		***3.24***		***1.72***	***5.67***		***6.80***	***26.17***

Tax Calculation										
Return		4.75		0.26		1.20		0.64		(13.76)
Add: Depreciation		4.97		0.19		0.84		0.44		16.36
less: CCA		(11.13)		(0.73)		(3.40)		(1.82)		(77.70)
		(1.40)		(0.29)		(1.36)		(0.74)		(75.10)
Tax rate		25.50%		25.50%		25.50%		25.50%		25.50%
		(0.36)		(0.07)		(0.35)		(0.19)		(19.15)
CCA		139.52		9.20		42.63		22.86		155.40
half year		-		-		-		-		(77.70)
UCC		139.52		9.20		42.63		22.86		77.70
CCA claimed	8%	11.13	8%	0.73	8%	3.40	8%	1.82	100%	77.70

Cost of Capital	***2013***
Return on Long-term debt	4.94%
Return on Short-term debt	2.01%
Return on Debt (blended)	4.75%
Return on Equity	9.16%

Table 2
CIS Full Year CCA Revenue Requirement Scenario

	2013		2014	
In Service Addition		155.40		139.04
Average Rate Base (no half year)		147.22		130.86
Depreciation	10.5%	16.36	10.5%	16.36
Return on Debt (blended)	4.75%	4.19	4.70%	3.69
Return on Equity	9.16%	5.39	9.44%	4.94
Tax	25.50%	(45.74)	25.50%	7.29
Total Incremental Revenue Requirement		**(19.80)**		**32.28**
Incremental Rate Impact		**-1.7%**		**4.6%**
Tax Calculation				
Return		(40.35)		12.23
Add: Depreciation		16.36		16.36
less: CCA		(155.40)		-
		(179.39)		28.59
Tax rate		25.50%		25.50%
Tax		(45.74)		7.29
CCA		155.40		-
				-
UCC		155.40		-
CCA claimed	100%	155.40		-

NON-TYPICAL CAPITAL - CUSTOMER INFORMATION SYSTEM

1.0 NEED

Hydro One's Customer Information System ("CIS") has reached its end of life and must be replaced immediately. This critical replacement falls under the capital spend category of non-typical spending as described in Exhibit B, Tab 1, Schedule 1.

The project, which allows Hydro One to improve service to customers, provides a more efficient customer system which is less costly to maintain than the obsolete customer information system installed in 1998 for the old Ontario Hydro.

Hydro One had planned the CIS program in-service date for 2016, however several factors prompted the necessity to bring forward the in-service date to 2013. The drivers for this change were as follows:

- Frequent changes to the system prompted by government initiatives amongst others, were putting customers and the Company at too great a risk for total system failure.
- An updated system to handle the IESO upgrades to Smart Metering/MDM/R processes and systems was required as the current systems are cumbersome, require significant manual effort, and are subject to frequent costly enhancements.
- The processes and systems built to handle new Distributed Generation ("DG") connections, process generation data and statements, and pay the generators, were built using the existing open market systems which are not scalable to handle the volumes of DG connections anticipated over the next three to five years. The new CIS will alleviate this problem in an integrated fashion.
- More formal demand management conservation obligations require the ability to implement, manage and track the resulting conservation programs in a more rigorous fashion in order to quantify the results and consequently refine and enhance the

scope, scale and efficacy of the programs. The new CIS will have the ability to implement and monitor CDM activities as part of mainstream customer service processes.

- The timeline leaves sufficient time for system stabilization before the possible transition of outsourced IT and Customer Care services provider functions. It was not feasible to conduct a CIS Replacement in parallel with the Outsourcing Contract RFP. Hydro One could not risk a change in a critical supplier mid-stream during the CIS Replacement project.
- The next feasible window, a 2016 start for 2019 cut-over, would result in the existing CIS being **20 years old** at the time of replacement. This would introduce a high amount of risk associated with a legacy system that is 20 years old with no vendor support as well as require increased expenditure for any system changes between now and 2019.

This project was presented to and discussed with stakeholders as part of an initial information session on June 29, 2011, and followed with an update at the stakeholder session on October 19, 2011. Please see Exhibit A, Tab 4, Schedule 1 for further details on the Stakeholder Consultation.

2.0 CURRENT CUSTOMER INFORMATION SYSTEM

The CIS project will replace Hydro One's end of life Customer Information System including customer/account services, billing, settlements, and open market systems. The CSS (Customer Service System) or Customer/1 application was purchased from Andersen Consulting (now Accenture). The application has undergone significant modifications in order to address the changes in the Ontario regulatory environment and to meet Ontario Energy Board requirements. This is an extensively customized product which is very costly to maintain and very costly to modify to meet new regulatory and business needs. Accenture no longer develops or supports the application.

Customer/1, installed in 1998, is the primary billing system for retail and general accounts. Changes to the system, no matter how small, generally represent core modifications which are expensive and time consuming. CSS runs on its own dedicated mainframe hardware which is expensive to maintain. The Open Market Systems suite ("OMS") is the set of applications that are integrated to perform the company's market transactions, settlements and complex billing functions. This suite was installed in 2002 to accommodate market opening. The OMS systems have since been modified to support market rule updates and the calculation of payments to generators.

CSS and OMS together effectively represent the "Cash register" of the company. Virtually all Distribution revenue flows through these two systems and thus their stability and operation are vital to the financial health of the company. Beyond that, CSS is also the platform with which we communicate with customers and initiate service orders to the field. The current CIS solution includes multiple custom applications integrated to meet various requirements. Many manual steps are necessary to meet customer, government and industry demands thus reducing productivity along the entire process life cycle.

3.0 PROJECT OVERVIEW

The CIS project is replacing the legacy CIS systems with a unified platform based primarily on SAP's industry leading billing application – Customer Relationship and Billing ("CRB"). For Meter Data management, Itron's Enterprise Edition application will use out-of-the-box integration with the SAP core to facilitate integration to and from the IESO for billing of Time Of Use residential customers as well as perform meter data management for interval billed commercial and industrial customers.

The project is expected to be in service in 2013. Approximately 30 disparate systems will be retired and replaced with the SAP and Itron applications. The Market rules and Settlements will be handled by a vendor supported SAP module. Meter Device information will also be migrated into SAP.

This implementation will upgrade numerous capabilities across the organization including customer interaction, customer demand management, service order processing, and meter management. By implementing SAP for CIS functionality, Hydro One will have an integrated enterprise platform based on SAP which will provide benefits in the CIS area due to its integration with the Work and Asset Management and Finance modules.

Total project costs by Phase, including OM&A are included in Table 1.

Table 1

CIS Project Costs by Phase and Item

($ Millions)

Item	Discovery	Blueprint Phase	Realization	Final Prep	Verification & Stabilization	TOTAL ($ million)
Implementation Effort (discovery, labour/services, commissioning and other support)	**$9.1**	**$21.0**	**$49.5**	**$38.0**	**$21.3**	**$138.90**
Hardware						**$10.0**
Software						**$13.4**
Interest and Overhead						**$17.5**
Total						**$179.8**

Table 2 identifies the CIS capital expenditures for the period 2011 to 2013.

Table 2

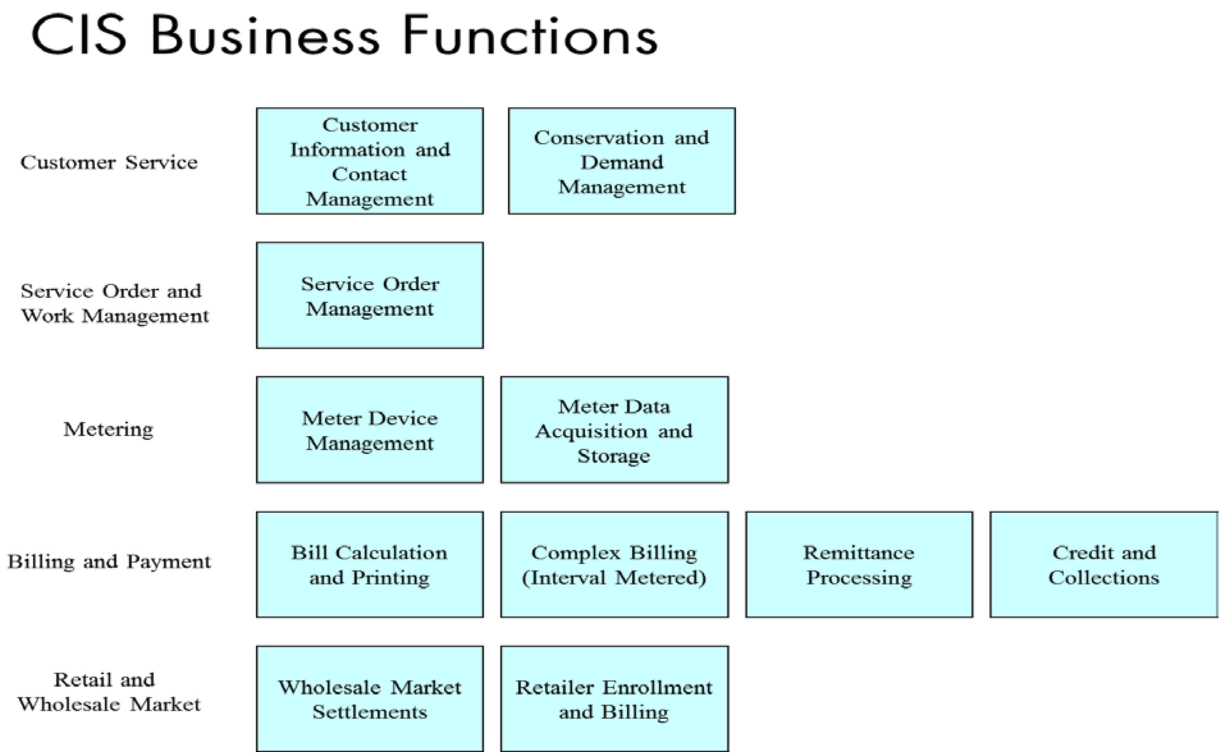
CIS Capital 2011– 2013 ($ Millions)

	2011	**2012**	**2013**	**Total In-service 2013**
Minor Fixed Assets	10.1	0		10.1
Development Project	41.5	85.7	18.1	145.3
Total Capital Cost	51.6	85.7	18.1	155.4

The CIS capital expenditures consist of Minor Fixed Assets and Development Costs. The latter includes all the costs to acquire, install and place into service the new systems.

Functional Overview:

Below is a high level overview of the functions enabled by the Customer Information System. The primary CIS functions are described in the detail following the graphic.



Customer Service:

Customer Information & Contact Management

The Customer Information and Contact Management function covers the capturing, look up and updating of customer, property, account, and service data required to perform utility customer care processes and activities. This data also enables interactions with customers, generators and other partners such as retailers and social service agencies.

Conservation and Demand Management

Conservation and Demand Management ("CDM") has been and continues to be a focus of Hydro One. There are numerous objectives and targets set internally and by the provincial government to help encourage the wise use of electricity and provide for a more environmentally friendly future. CDM is a provincial government mandated program aimed at reducing demand through load control and load shifting to off-peak times, and reducing energy consumption through conservation and efficiency. CDM functionality is limited to tracking the programs in which the customer is enrolled. The embedded CDM functionality provided by the new CIS adds no additional cost to the project.

Service Order and Work Management:

Service Order Processing

Hydro One's customers request work to be performed – such as new connections to Hydro One's distribution system, underground cable locates, etc. The Service Order Processing function receives and responds to these customer/internal requests via the Customer Information System.

Metering:

<u>Meter Device Management</u>

This function encompasses the life cycle management of metering devices, specifically meters and instrument transformers (current and potential) – from set up to retirement. Each device must be uniquely identified and the complete definition of its attributes must be maintained in a system that Measurement Canada, as the regulatory body, accepts as the 'System of Record'. In addition, the definition of the attributes of each meter installation must also be managed. Both functions are necessary to meet technical and regulatory requirements in order to measure and bill, or pay customers for their electricity consumption and/or power production.

<u>Meter Data Acquisition and Storage</u>

The Meter Data Acquisition and Storage function covers the retrieval and processing of meter readings to provide data required to bill consumers and settle with electricity providers. This capability will facilitate integration to and from the IESO for billing of Time of Use residential customers as well as perform meter data management for interval-metered commercial and industrial customers.

Billing and Payment:

<u>Bill Calculation and Printing</u>

The Bill Calculation and Printing Function covers the billing determinant processing, bill calculation and invoice production for approximately 1.2 million customers. Customer bills are comprised mainly of delivery, commodity and regulatory charges. Also included in the calculation and display of the bill are late payment charges, and other miscellaneous debits and credits.

Bill presentation includes the formatting of the statement, and the delivery of that statement to the customer via Canada Post or web-based electronic presentment. As part of the bill presentment process, bill messages and bill inserts are prepared and delivered to specific customer segments along with the bill itself.

As the bill is calculated, various checks and controls are performed to minimize the risk of a customer receiving an incorrect bill. The CIS system supports the execution of these checks, together with workflow functions to support the manual handling of the resulting exceptions, and the efficient execution of billing adjustments, cancellation and rebilling as necessary.

<u>Complex Billing</u>

The Complex Billing function covers the meter data processing and bill calculation of interval metered customers connected to Hydro One's distribution system. These customers include the largest commercial and industrial accounts, retail generators and other local distribution companies ("LDCs"). It also includes the billing of embedded wholesale market participants (i.e., those connected to Hydro One's distribution systems), who are billed for commodity related charges by the province's Independent Electricity System Operator ("IESO") and by Hydro One for delivery related charges.

<u>Remittance Processing</u>

Hydro One partners with TD Bank and Symcor, as well as other payment processors, to handle the processing of payments received from customers. Encrypted payment files are received daily and posted to customer accounts via CIS. CIS reconciles payments via our SAP financial modules.

Credit & Collections

The Collection program is responsible for mitigating financial risk and debt exposure by applying and maintaining security deposits and by completing electricity disconnection in response to customer non-payment of arrears. Credit and Collections activities are conducted in compliance with OEB regulations which define specific business rules around, for example, the payment and refund of security deposits.

Retail and Wholesale Market:

Wholesale Settlements

The Wholesale Settlements functional area covers Hydro One's financial and related wholesale market transactions with Ontario's Independent Electricity System Operator and the procurement of power from retail generators connected to Hydro One's distribution systems. It also covers settlement with other Local Distribution Companies connected to Hydro One's distribution systems for power purchased at retail points of delivery and power supplied under short-term and long-term load transfer arrangements with those distributors.

Retailer Enrolment & Billing

In the Ontario electricity market, energy customers have a choice when it comes to the purchase of their electricity commodity. The Ontario market has almost 20 active electricity retailers. Hydro One has over 140,000 customers actively enrolled with electricity retailers.

The Ontario market rules support a bill-ready retailer billing model, in which the LDCs inform electricity retailers of the amount of electricity consumed by each of their customers, and the retailers inform the LDCs of the commodity charge to add to their customer's bills. In a bill-ready market, the retailers are required to calculate the commodity charge based on the customer's consumption. This market supports both distributor consolidated billing ("DCB") and retailer consolidated billing ("RCB"). For a DCB customer, the bill is issued by Hydro One to the customer using the commodity charge ($) provided by the retailer and all other charges as calculated by Hydro One. For a RCB customer, all of the charges normally billed to the customer (including the commodity charge) are billed by the retailer. The retailer decides which bill option they will use. CIS functionality in this area also automates the calculation and processing of settlement payments between Hydro One and the retailers who do business within Hydro One's service territory.

Data and Reporting Improvements:

As part of the CIS project, Hydro One will be extending the existing SAP Business Intelligence ("BI") solution which was implemented as part of the earlier Cornerstone phases. As a result, the BI solution will be extended to include the customer, billing, metering and payment data which is in scope for the CIS solution. This will allow the new data to be combined with the existing asset, financial and resource data which is being gathered in the current SAP solution. There are two major benefits associated with this ability:

- significant effort is required today from IT staff to extract data from legacy CIS systems, due to the age and complexity of the technology employed. In future, Hydro One staff will be able to access the BI solution themselves and 'self-serve' many of their requests; and
- the ability to combine data relating to both customers, and their usage patterns, with distribution system data (assets, outages, work programs) will enable better insight into Hydro One's business operations, and the relationship between customer behaviour/satisfaction and the performance of the distribution system.

The improved usability of the BI solution coupled with the richness of the data available, will assist Hydro One in business planning to optimize operational and capital expenditures from a safety, reliability and customer satisfaction perspective.

4.0 CUSTOMER CARE/CIS COSTS AND BENEFITS

4.1 Costs

At the June 29, 2011 Stakeholder session, stakeholders requested Hydro One provide a template similar to the one Enbridge Gas Distribution Inc. included in their application EB-2011-0226, Exhibit JCTC1.4 (See June 29 Stakeholder Notes, Appendix B, Item 6, included in Exhibit A, Tab 4, Schedule 1, Appendix C). Hydro One's template, shown as Table 3, includes the line items which represent the Hydro One CIS costs equivalent to those Enbridge included in its template as agreed with its stakeholder group.

Table 3

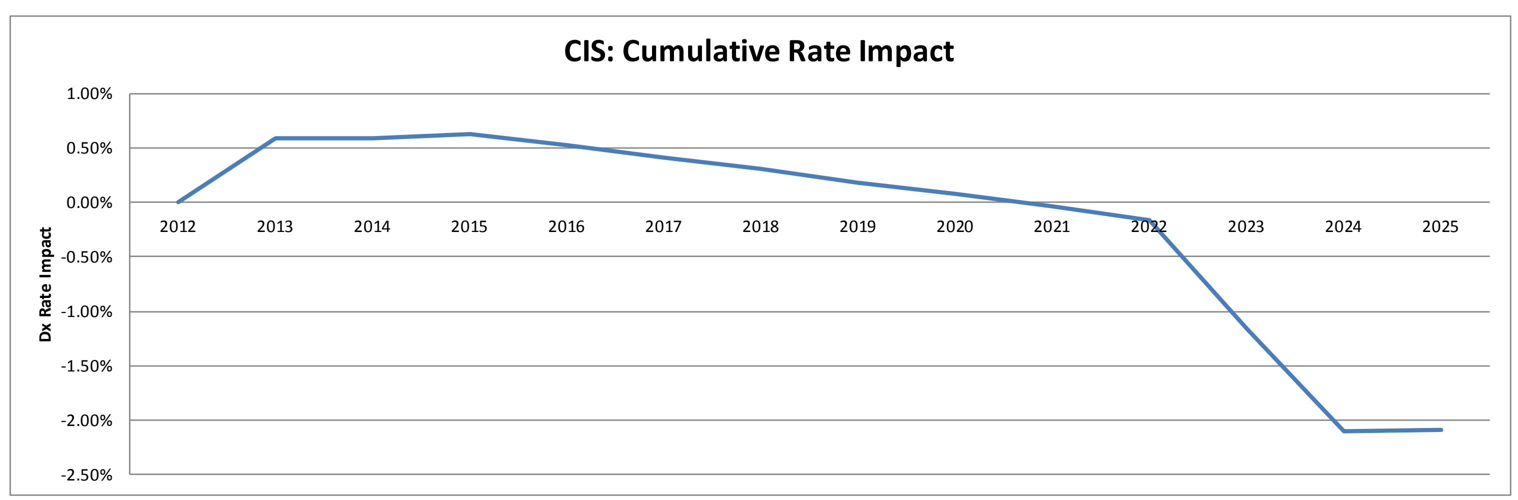
CORNERSTONE

CIS Cost Template

#	Category of Cost	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2009 - 2024 Total
	LEGACY CIS COSTS																	
1	License Fees	$1,108,600	$1,108,600	$1,108,600	$1,108,600	$461,917												$4,896,317
2	CIS Hosting & Support	$15,134,259	$15,134,259	$15,134,259	$14,636,716	$6,098,632												$66,138,123
3	CIS Backoffice	$3,907,408	$3,962,116	$3,843,227	$3,843,227	$1,601,345												$17,157,323
	LEGACY CIS COSTS SUBTOTAL	**$20,150,267**	**$20,204,974**	**$20,086,086**	**$19,588,543**	**$8,161,893**												**$88,191,763**
	NEW CIS COSTS																	
4	License Fees					$1,801,243	$2,421,685	$2,421,685	$2,421,685	$2,421,685	$2,421,685	$2,421,685	$2,421,685	$2,421,685	$2,421,685	$2,421,685	$2,421,685	$28,439,778
5	CIS Hosting & Support					$7,926,108	$9,958,897	$7,133,131	$7,133,131	$7,133,131	$7,133,131	$7,133,131	$7,133,131	$7,133,131	$7,133,131	$7,133,131	$7,133,131	$89,216,313
6	CIS Backoffice					$2,442,603	$4,110,577	$2,793,227	$2,793,227	$2,793,227	$2,793,227	$2,793,227	$2,793,227	$2,793,227	$2,793,227	$2,793,227	$2,793,227	$34,485,455
	NEW CIS COSTS SUBTOTAL					**$12,169,954**	**$16,491,158**	**$12,348,043**	**$12,348,043**	**$12,348,043**	**$12,348,043**	**$12,348,043**	**$12,348,043**	**$12,348,043**	**$12,348,043**	**$12,348,043**	**$12,348,043**	**$152,141,545**
7	**CIS Project Costs @ 40% Equity**					**$6,798,917**	**$6,798,917**	**$30,955,707**	**$29,973,306**	**$28,668,294**	**$27,398,776**	**$26,106,948**	**$24,807,886**	**$23,495,209**	**$22,185,898**	**$10,761,240**	**$0**	**$237,951,098**
	TOTAL CIS COSTS:	**$20,150,267**	**$20,204,974**	**$20,086,086**	**$19,588,543**	**$27,130,764**	**$23,290,076**	**$43,303,750**	**$42,321,349**	**$41,016,337**	**$39,746,819**	**$38,454,991**	**$37,155,930**	**$35,843,252**	**$34,533,941**	**$23,109,283**	**$12,348,043**	**$478,284,406**
	Number of Customers	1,189,183	1,201,195	1,210,889	1,220,514	1,231,476	1,243,713	1,256,331	1,268,421	1,280,511	1,292,600	1,304,689	1,316,779	1,328,869	1,340,958	1,353,048	1,366,579	20,405,755
	CIS Cost per Customer	$16.94	$16.82	$16.59	$16.05	$22.03	$18.73	$34.47	$33.37	$32.03	$30.75	$29.47	$28.22	$26.97	$25.75	$17.08	$9.04	$23.44
	CIS Cost per Customer Annual Change			-1.4%	-3.2%	37.3%	-15.0%	84.1%	-3.2%	-4.0%	-4.0%	-4.1%	-4.3%	-4.4%	-4.5%	-33.7%	-47.1%	

The overall impact of the CIS project investment on the DX rates is summarized below. This is as requested by stakeholders (see Item 7, Appendix B, Notes from Stakeholder session of June 29, 2011)

#	Category	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2009 - 2024 Total
8	**CIS Revenue Requirement**					**$6,798,917**	**$6,798,917**	**$7,248,911**	**$6,069,530**	**$4,761,761**	**$3,459,279**	**$2,046,071**	**$824,253**	**($498,967)**	**($1,852,916)**	**($13,279,389)**	**($24,142,480)**	**($1,766,111)**
9	**2011 OEB Approved Revenue Requirement**					**$1,148,885,481**	**$1,148,885,481**	**$1,148,885,481**	**$1,148,885,481**	**$1,148,885,481**	**$1,148,885,481**	**$1,148,885,481**	**$1,148,885,481**	**$1,148,885,481**	**$1,148,885,481**	**$1,148,885,481**	**$1,148,885,481**	
10	**Dx Rate Impact (Cumulative)**					**0.59%**	**0.59%**	**0.63%**	**0.53%**	**0.41%**	**0.30%**	**0.18%**	**0.07%**	**-0.04%**	**-0.16%**	**-1.16%**	**-2.10%**	



4.2 Table 3 Cost Descriptions

Rows 1 and 4 – License fees

These rows represent the fees paid to commercial software vendors for maintenance of the licensed CIS software. In the legacy CIS environment this includes fees paid to Accenture for the Customer/1 foundation software, fees paid to Itron and other software vendors for the applications included in the OMS suite, and miscellaneous other maintenance contracts including mainframe operating system support.

In the new CIS environment, these costs increase in aggregate due to the maintenance fees associated with the new CIS software components licensed primarily from SAP and Itron. These increases are partially offset by the elimination of the mainframe legacy CIS software and the elimination of some components of the OMS suite of applications.

Rows 2 and 5 - CIS Hosting and Support

This row represents the charges from Inergi for:

- Maintaining and fixing issues associated with the CIS applications. The CIS is managed in a problem management framework, to service levels that have been established with the relevant lines of business within Hydro One and which reflect the criticality of these applications.
- Operation, maintenance, and management of hardware (servers, mainframe, storage area network and data storage devices), operating systems, associated applications and infrastructure required to run the CIS applications, including the costs incurred to provide back up and disaster recovery capability for these applications.

With the implementation of the new CIS, which is based on commercial off-the-shelf software, and which is configurable instead of requiring expensive time consuming code changes, it is anticipated that the service provider costs will reduce considerably once the new CIS application has been stabilized. The new CIS application will also allow the existing mainframe computers to be retired, which will provide further savings. These savings will be fully realized via the re-tendering of IT services which will occur prior to 2015 when the current Inergi contract expires.

Rows 3 and 6 - CIS Backoffice

These rows are the costs of Hydro One staff who oversee the maintenance and operation of the CIS, and who oversee the implementation of changes to the CIS to meet regulatory and customer service requirements. It also includes costs from Hydro One's Customer Care service provider to provide CIS-related services including an end-user helpdesk, quality assurance (to ensure that the CIS application is producing accurate business outputs such as customer bills), reporting, and user acceptance testing of regular monthly releases of CIS.

As for the application maintenance activities, the implementation of the new CIS is anticipated to produce lower costs in this area once the new CIS application has been stabilized. This is due to the configurable nature of the application and the fact that it is based on off-the-shelf software which is supported by the vendor. These savings will be fully realized upon the re-tendering of the IT services contract.

The costs reflected in lines 1 to 6 show what is necessary to operate and maintain the applications (either legacy CIS or new CIS) in a fully functional state to support the customer service and billing business processes based on current business requirements. They do not include the cost of any future development activity, application enhancements, or refresh of the application software or associated hardware. Such costs will be included in future cost of service filings.

Row 7 – New CIS project capital costs

The total cost depicted in Row 7 is Hydro One's regulated return @ 40% equity.

Row 8, 9 and 10 – Revenue requirement and rate impact of CIS

Row 8 represents the annual revenue requirement for CIS after allowing for the impact of CIS benefits. Row 9 is the 2011 OEB approved revenue requirement used as the basis of determining cumulative rate impact due to CIS. Row 10 shows the projected impact of CIS on distribution rates, expressed as a percentage change relative to the base revenue requirement shown in Row 9. Any future cost of service applications and work program changes are not included in this calculation.

4.3 Savings and Benefits Summary

Hydro One expects Distribution Business savings from the CIS implementation to total $172 million over a 7 year time horizon.

Hydro One continues to explore opportunities with other Ontario LDCs to look for project cost savings synergies associated with sharing knowledge and deliverables regarding Hydro One's CIS implementation. Any such cost savings will be reflected in lower project and on-going costs. Hydro One has insufficient information at this time to quantify the amount of these potential savings.

CIS benefits have been identified through collaborative efforts by Hydro One, the CIS solution integrator, SAP and Hydro One's outsourced partners. The benefits approach has been developed based on our CIS solution integrator's best practices/framework. The benefits from CIS are enabled primarily through application and process changes, greater data transparency, integration and collaboration across Hydro One's Lines of Businesses.

The CIS investment enables a future customer service delivery model that will: meet the needs of the evolving utility customer of the future; support the achievement of key corporate objectives

(Customer Satisfaction, Innovation, Productivity); and ensure that related strategic technology investments yield maximum value.

Customer Care

An integrated CIS which provides a 360 degree view of the customer profile with enhanced customer issue resolution capability will reduce handling time on calls and correspondences, improve billing timeliness and accuracy, increase first call resolution ("FCR") and improve customer satisfaction.

Included in these benefits are avoided cost savings associated with the high cost of customizing an end of life legacy customer information system to meet ongoing and future business needs (See Attachment 1 for Ontario Green Energy Benefit Example). The new CIS based on a standard SAP platform is easier to configure and will require less agent training time. There will also be a reduction of bad debt expense through better tracking of delinquent accounts and more efficient collection processes. Integration of CIS with other enterprise SAP platforms and new technologies such as smart meters will drive work force productivity improvement

Finance

Benefits will be realized through reducing the time required to issue bills which will result in significant cash flow savings. Accounting processes will also be streamlined in the new CIS due to the integrated nature of CIS with the existing SAP ECC platform.

IT

Benefits will be realized through operational and capital savings from the decommissioning of mainframe. Rationalization of the hardware environment on which SAP runs will reduce infrastructure management and support costs as well as facility costs and hardware refresh. A common SAP platform for CIS enhances productivity in the area of application maintenance support and enhancement work program across Hydro One and Hydro One's outsourced service provider.

5.0 STAKEHOLDER INFORMATION REQUESTS

As previously mentioned, the CIS project was presented to and discussed with stakeholders as part of an initial information session on June 29, 2011, and followed up with an update at the stakeholder session on October 19, 2011. During those sessions there were several stakeholder requests for specific information to be included in Hydro One's CIS evidence. The information requested by stakeholders is included in the following sections.

5.1 Cost for Hydro One staff working on CIS Project

Hydro One was asked to provide more details about the estimated costs for the use of Hydro One personnel in the project, with specific interest in the costs of back-filling for seconded staff. (See June 29 Stakeholder Notes, Appendix B, Item 17, included in Exhibit A, Tab 4, Schedule 1, Appendix C).

The cost for Hydro One staff on the CIS project is shown in the Table 4.

Table 4
Costs for Hydro One staff on CIS Project

($M)	2011	2012	2013	TOTAL
Hydro One	4.7 *	6.8 *	4.7 *	16.2

***costs area allocated to Capital or OMA based on accounting treatment for work activity**

In very large projects such as CIS, it is typical that significant numbers of key staff are seconded to the project for a number of months / years, leaving a resource gap in the home base organization. The intent of the cost treatment applied to this project is to provide funding for the home base organizations to bring in backfill resources through either temporary employees or external contract staff. It should be noted, however, that in some circumstances staff have been moved from another capital project in which case their costs would not impact OM&A.

5.2 Project Contingency

Hydro One was asked to provide more details about the project contingency and the governance of these funds. (See June 29 Stakeholder Notes, Appendix B, Item 8, included in Exhibit A, Tab 4, Schedule 1, Appendix C).

In very large projects such as CIS, Hydro One includes a portion of funding in contingency to cover any project issues such as clarification on requirements, system issues, technology performance and external factors unknown to the project at the time the business case is approved. Due to the complexity of the CIS project, Hydro One expects to use the contingency, and the Board of Directors has approved the release of these funds.

5.3 Ontario Clean Energy Benefit implementation

Hydro One was asked to provide more information about the study that was referenced in the session which illustrated the cost of making changes in the legacy CIS vs. the new CIS. (See June 29 Stakeholder Notes, Appendix B, Item 10, included in Exhibit A, Tab 4, Schedule 1, Appendix C).

Ontario Clean Energy Benefit study:
The implementation of the Ontario Clean Energy Benefit is representative of the type of change to customer charges that Hydro One has to implement from time to time. Implementing this change in the existing CIS system – CSS – was performed by Inergi late in 2010, on a very aggressive timeline. As with all billing changes there was considerable detail to be worked through in design to determine:

- exactly which customers were eligible
- how the benefit would be calculated for each different charge and each customer type
- how the benefit would be displayed on the bill
- how the benefit would be calculated and displayed in the cutover month
- what accounting would occur for the benefit and therefore what information the CIS would need to feed to the Finance systems to support proper accounting
- what were the reporting requirements for the benefit.

A solution was proposed and validated, and then the changes were designed to all the various modules of CSS that needed to be updated in order to produce the required outcome. As the code changes were made, a comprehensive set of test scenarios was identified in order to test all the impacted account types through the cutover and ensure that the code changes were working properly. As always, the implementation of the this change had to be coordinated with other changes occurring in the CIS systems at the same time, to ensure cross impacts were identified and mitigated.

The actual effort to implement these changes in the legacy CIS was 4,480 hours broken up as follows:

Phase	Hours
1 – Planning	221
2 – Design	794
3 – Build	1,264
4 - Test	448
5 – Deploy	160
6 - Post Production Support	302
7 - Process & Training	186
8 - Project Management	1,105
Grand Total	**4,480**

Within the new SAP-based CIS, the design and implementation of a charge or credit like OCEB is simplified since the implementation can be handled through configuration of billing parameters in SAP – the benefit can be defined as a charge type, eligibility for the charge type can be defined in configuration tables, and the other charges to which the OCEB benefit is to be applied can also be defined in configuration tables. Significantly, the definition of the charge type includes the definition of how the charge is pro-rated at the beginning and the end of the period of time (currently defined as five years) during which the OCEB is to be applicable. Hence the effort estimate for the planning, design, build and test of OCEB in the new CIS was reduced from 2,727 hours to approximately 800 hours. Other elements of the estimate were reduced to a lesser extent, creating an overall estimate of 1,600-2,200 hours as noted below

<table>
<tr><th>Phase</th><th>Hours</th></tr>
<tr><td>1 – Planning</td><td rowspan="4">800</td></tr>
<tr><td>2 – Design</td></tr>
<tr><td>3 – Build</td></tr>
<tr><td>4 - Test</td></tr>
<tr><td>5 – Deploy</td><td>80-120</td></tr>
<tr><td>6 - Post Production Support</td><td>140-240</td></tr>
<tr><td>7 - Process & Training</td><td>80-140</td></tr>
<tr><td>8 - Project Management</td><td>500-900</td></tr>
<tr><td>Grand Total</td><td>1,600-2,200</td></tr>
</table>

Attachment 1 to this exhibit provides the estimate from our CIS System Integrator HCL-Axon for the cost of implementing the Ontario Clean Energy Benefit in the new CIS solution.

5.4 Hydro One Board Approval document

Hydro One was asked to provide the Hydro One Board Approval document for the CIS Project (See June 29 Stakeholder Notes, Appendix B, Item 5, included in Exhibit A, Tab 4, Schedule 1, Appendix C). The Hydro One Board document is provided as Attachment 2.

SMART GRID

1.0 INTRODUCTION

In the last Distribution Cost of Service proceeding the Board approved a smart grid funding adder for OM&A and Capital finding the expenditures to be prudent. This rider expired on December 31, 2011. This section details the 2013 incremental smart grid OM&A expenditures of $19.8 million. These investments support the provincial government's smart grid, renewable generation and energy conservation objectives, while providing improved distribution operations. Hydro One is seeking approval of a rate rider for the recovery of this expenditure to allow the company to continue deploying smart grid and in so doing to meet its service delivery obligations.

Table 1 contains a breakdown of the required smart grid OM&A expenditures in 2013.

Table 1
Incremental Smart Grid OM&A Expenditures
($ million)

Smart Grid OM&A Expenditures	**2013**
Sustainment of Installed Smart Grid Systems	7.0
OM&A Component of Additional Smart Grid Deployment	8.6
Smart Grid Studies	4.2
TOTAL	**19.8**

In EB-2009-0096, the Board approved the first phase of Hydro One's Smart Grid plan, primarily work in the Smart Zone pilot in Owen Sound and the need to facilitate connection of many FIT and MicroFIT generators. Hydro One has executed the Smart Grid plan and requires additional OM&A funding in 2013 for:

Sustainment of Installed Smart Grid Systems

As Hydro One has executed its Smart Grid plan, the Company has installed a base of new smart grid assets including a Distribution Management System ("DMS"). These assets were installed to meet our obligation to connect a large number of FIT and microFIT generators on the Hydro One distribution system. These new assets require incremental OM&A to fund their sustainment. Without this incremental OM&A, the investment in these assets would be stranded and we would be unable to meet our obligation as a distribution operator.

OM&A Component of Additional Smart Grid Deployment

As Hydro One continues to execute its Smart Grid plan and connect increasing numbers of FIT and microFIT generators, additional smart grid deployment of field devices and back office systems are required. These assets will enable the efficient connection of renewable generators on the Hydro One distribution system, provide operational and efficiency benefit to Hydro One, and provide customers with tools to reduce their electricity use. Any delay in continuing the Hydro One Smart Grid plan will result in unnecessary demobilization and mobilization costs as well as delay potential benefits to our customers.

Smart Grid Studies

Hydro One has undertaken multi-year commitments with other organizations to identify, monitor, evaluate and validate new and emerging smart grid technologies - including laboratory and field demonstrations in order to support the timely deployment of Smart Grid. In order to maintain the deployment schedule for the overall Smart Grid Program, the schedules for the Smart Grid Studies Program must be maintained. These schedules necessarily include funding requirements for a series of Smart Grid Studies Program work required to be completed in 2013.

2.0 HYDRO ONE IS EXECUTING ITS SMART GRID PLAN APPROVED IN EB-2009-0096

In the previous Distribution rate application (EB-2009-0096) for 2010 and 2011, the OEB decided that

> *"Hydro One's Smart Grid plan includes many of the activities identified in the Board's filing guidelines regarding smart grid. Generally, the Board finds that the activities identified in Hydro One's Smart Grid plan are consistent with the filing guidelines.*"

> … and that

> *"Therefore, the Board concludes that the costs as budgeted are prudent, and should be recovered in rates."*

The approved capital and OM&A expenditures are summarized in Table 2.

Table 2
OEB Approved Smart Grid Capital and OM&A Expenditures
($ million)

	2010	**2011**
Capital	30.1	62.4
OM&A	10.0	10.0

As indicated in EB-2009-0096, a significant portion of the proposed smart grid expenditures were with respect to the Smart Zone Pilot project. The Smart Zone serves as a test-bed site for new smart grid technologies and product applications to confirm their viability prior to widespread deployment in the Hydro One distribution system. This is a fundamental aspect of Hydro One Distribution's approach and strategy for the development of the smart grid and for making prudent investments.

Given the Board's prudency finding, in addition to the Smart Grid OM&A expenditures describe in this exhibit,, Hydro One is also proceeding with Smart Grid capital work in 2012 and beyond, consistent with its Smart Grid Plan, the Ministerial Directive of 2010 and the Feed-in-Tariff review of 2012. As directed by the Board, Hydro One will apply for the recovery of these capital costs in a future cost of service application. In order to facilitate the future recovery Hydro One will continue to track these capital expenditures in the variance account approved in EB-2009-0096.

The Smart Grid Plan is structured as a multi-year, multi-phase/release project. Phase 1, Release 1 described in the EB-2009-0096 proceeding, was primarily focused on laying down the foundation required to manage distributed generators (DGs). It delivered many of the foundational elements that will enable the overall Smart Grid Plan including a Distribution Management System (DMS) at the OGCC, a new protection, control and telecommunications building at Owen Sound TS, and the deployment of many smart devices in the Owen Sound operating centre. Phase 1 Release 2 builds on the investments and the learning from Release 1 to create value for Hydro One and its customers.

Phase 1 Release 2 investments will include:

- The upgrade of the DMS and pilot of DG control and power quality monitoring.
- The integration of the DMS with energy storage systems in the Tilsonburg area.
- The installation of voltage regulating devices integrated with the DMS on the distribution system to pilot Conservation Voltage Reduction.
- The integration of a demand response system with our AMI (smart meter) network.
- The integration of the AMI with the DMS and the Outage Management System through an Operational Service Bus to optimize outage response.
- The implementation of the Energy Theft Analytic system.

Given the above expenditures are similar in nature and consistent with the spirit of the Board's EB-2009-0096 approval, Hydro One believes it is appropriate to continue to track the Phase 1 Release 2 investments in the approved variance account.

Details of the OM&A expenditures for which Hydro One is seeking the establishment of a new rate rider for 2013 is described in the following sections.

3.0 SUSTAINMENT OF INSTALLED SMART GRID SYSTEMS

Release 1 of the Advanced Distribution System ("ADS") project established new systems that now need to be maintained. This creates additional OM&A costs in the form of licensing fees, computer infrastructure maintenance and staff to maintain the DMS system and other equipment.

Sustainment of New Smart Grid Systems	**$7.0M**

DMS is a new control system that needs to be maintained

The OGCC currently has two main control systems: a Network Management System to operate the transmission system, and the Outage Response Management System to handle trouble calls during storms and outages. The installation of the DMS represented a step-change increase in the computer infrastructure and IT support. As the DMS needs to perform computationally intensive state estimation and load flow algorithms on a distribution system that is 10 times the size in circuit kms of lines as the transmission system, it requires extensive infrastructure (servers, networking devices, firewalls). The DMS also requires a network model that is accurate and maintained to be in sync with the actual distribution system in the field in order to provide for the correct state estimation and load flow results. This requires a team to maintain the network model of the distribution system in the DMS. The DMS also comes with a host of power applications that will require power engineering and computer science expertise to operate and maintain on behalf of the control room.

Hydro One's distribution system was designed and built to serve 6,000 MW of peak load with one direction of power flow to 1.2 million load customers. The government laid out an objective in the Long Term Energy Plan that will see Ontario served by 10,700 MW of renewable generation overall. It is expected that 4,000 to 5,000 MW of that renewable energy will be installed on the Hydro One distribution system, with over a thousand MWs already installed and up to 4,000 MW of signed connection agreements scheduled over the next few years. This is already creating situations of reverse power flow on parts of the system. The DMS uses knowledge of the distribution network model, the limited points of telemetry currently available, and the customer load profiles to estimate the voltage and power flow on the distribution system. With this information, operators will be informed proactively of the direction of power flow and out-of-normal voltage levels on the distribution system.

Control room evolving to specialized distribution operators

The control room is also evolving due to the integration of renewable generation on the distribution system. The current control room has one class of operator. The current OGCC Controller operates the transmission system. With renewable generation proliferating on the distribution system along with an objective to improve distribution operations the control room will evolve into separate transmission and distribution operator's functions. This control room structure can be found at leading utilities such as BC Hydro, Florida Power & Light and Southern California Edison. The specialization between transmission operator and distribution operator will require a net increase in the number of operators. In addition, an extensive training program needs to be developed to train the distribution operators.

4.0 OM&A COMPONENT OF ADDITIONAL SMART GRID DEPLOYMENT

The ADS project is completing its first release by the end of 2012. Hydro One is looking to continue executing its Smart Grid plan by commencing Release 2 of the ADS project in 2013. This release is expected to deliver further enablement of DG, operational improvements for Hydro One, and improved conservation options for Hydro One customers.

Release 2 will implement new smart grid field assets as well as new back office systems. The new release includes costs associated with software development, process development and training development. Therefore there is a need for incremental OM&A to continue this project.

OM&A Component of Release 2 Project	**$8.6M**

To support the next phase of the smart grid program, Hydro One will make prudent investments in smart grid to provide the additional capabilities highlighted in Table 3.

Table 3

Release 2 Smart Grid Capabilities

Business Objective	Capability Today	Release 2 Capability
Enable More Distributed Generation using Existing Assets	No ability to control DGs other than tripping the feeders and causing a local area black out. Number of DGs limited to engineering limits, requiring new assets for additional DGs.	Provide ability to dispatch DG for transmission system reliability and enable more generation within existing assets. Number of DGs limited to real-time operational limits.
Use Energy Storage to Integrate DG	No energy storage projects deployed currently.	Pilot both battery and flywheel energy storage technologies in Owen Sound as tools to accommodate DGs.
Improve Outage Restoration Times and Efficiency	Wait for customers to call Hydro One to inform us their power is out and then dispatch field crews to search for the outage by patrolling the line.	Use smart meters to reduce trouble call costs and improve outage response times.
Catch & Reduce Energy Theft	Manually analyze customer energy usage for patterns where energy usage is the same hour-to-hour, day-to-day to provide targets for investigation.	Use smart meters and localized line loss analysis in the Distribution Management System to better identify and stop energy theft.
Demand Response for Consumers	40,000 customers have signed up for a critical peak pricing program where a pager-enabled thermostat is raised by 2 degrees during critical peak days.	Use smart meters to provide customers with real-time in-home monitoring and new CDM programs. Also trial using voltage regulating devices to save energy for customers.
Increased Energy Efficiency	Engineer feeder so that the last customer at end of the feeder has voltage within acceptable range by boosting voltage at beginning of feeder.	Manage the voltage along the feeder in real-time so that all customers along the feeder are receiving electricity at the low end of the acceptable voltage range, reducing customers' energy consumption.

5.0 SMART GRID STUDIES PROGRAM

Smart Grid Studies	**$4.2M**

A necessary and critical component of Hydro One's Smart Grid Deployment Plan is the Smart Grid Studies Program. For 2013, the program requires $4.2M in OM&A funding. Smart Grid is a relatively new and evolving construct that is being shaped by new and emerging technologies. The successful deployment of Smart Grid is predicated on Hydro One's proactive and lead role amongst a wide variety of manufacturing, university and college research institutes, government agencies and other utility participants. In so doing, Hydro One is moving to fulfill its obligations to its customers while concurrently responding to Ontario government's directions under the *Green Energy and Environment Act, 2009.*

As noted in EB-2009-0096, Hydro One has undertaken multi-year commitments with various participants in order to support the timely deployment of Smart Grid. These commitments in many cases take the form of joint funding collaborations with a number of participants. The programs involve identification, monitoring, evaluating and validating new and emerging smart grid technologies - including laboratory and field demonstrations – and collaboratively sharing associated information and findings with the participants.

This collaborative approach to funding is allowing Hydro One to leverage the OM&A expenditure and maximize its return on program investment.

These multi-year commitments are scheduled to support the larger Smart Grid Program. That is, in order to maintain the deployment schedule for the overall Smart Grid Program, the schedules for the Smart Grid Studies Program must be maintained. These schedules necessarily include funding requirements for a series of Smart Grid Studies Program work required to be completed in 2013.

Hydro One's multi-year commitments are of three general types:

1. Home energy management technologies;
2. Distributed generation integration and real-time management technologies; and
3. Energy storage technologies required to address solar and wind generation voltage fluctuation issues.

For example, home energy management technologies allow residential energy users to more effectively manage energy. Studies to date have demonstrated that smart grid technology can modify residential consumer behavior to conserve overall electricity consumption by 6.5%. Work needs to continue in 2013 in order to further develop commercial, agricultural and industrial consumer load profiles, user friendly web portals and a universal connector for in-home devices to work with Smart Meters.

A comprehensive listing of the Smart Grid Studies initiatives required to be funded in 2013 is presented in Table 4.

1 **Table 4**

SMART GRID STUDIES PROGRAM - 2013	SCOPE
Energy Storage Systems (Li-Ion Battery, Flywheel) Technologies.	Grid integration for multi year demonstration of large scale energy storage devices using flywheel and Li-Ion technologies in participative projects by Electric Power Research Institute (EPRI), Natural Resources of Canada(NRCan),Ontario Center of Excellence(OCE) with multi partner participation by governments, agencies, universities and the industry.
Energy Hub Management – Automated Home Energy Networks	Optimization in customer loads, generation, import, export and energy storage to further minimize cost of energy including development of web portal, In-Home devices to work with smart meters in collaboration with universities, OCE, NSERC, OPA and Local Distribution Companies(LDC).
Inverter, Flexible Alternating Current Distribution System (FACDS) Technology /Devices Studies	Performance assessment and validation of inverters as FACDS device interfaces to distribution grid for Wind and Solar generators in collaboration with universities, industry partners and OCE/ERI.
NSERC Micro Grid Networks by British Columbia Institute of Technology (BCIT) to develop and demonstrate Micro Grid Networks in a Canadian context	Development and Validation of Operation, Control and Protection ; Optimization and Regulatory issue, Information Technologies for Smart Micro Grid Network in participation with 26 other partners from Canadian Universities (9), industry (7), BC Hydro, New Brunswick Power, OPA, IESO, NRCAN, OCE, BCIT and Research Companies(3).
Advanced Grid Studies (various technology assessment and validation on distributed generation as well as as advanced grid options)	Technology development and validation work for grid integration and impact of renewable energy, grid Interface devices with performance and quality validations, electric vehicles and chargers, optimization of volt-var and, intelligent devices and sensors in collaboration with universities, EPRI, NSERC and OCE.
Clean Energy Initiatives (Geothermal, Combined Heat and Power, Pollution Probe, Center for Clean Energy)	Pollution Probe (PP), Centre for Clean Energy(CCE) and Toronto Atmospheric Funds(TAF) sponsored joint projects assessments, development and validation of clean renewable distributed generation for effective demand management.
Green Energy Impact / Integration Studies (Wind, Solar, Biomass Generation connections impact studies)Hierarchical Management, Control and Optimization)	Specific impact and integration studies of Green Energy renewable generation as they relate to power quality, protection and control, optimization and validation of hierarchical volt-var management with universities, NSERC and OCE..

SMART GRID STUDIES PROGRAM – 2013	**SCOPE**
Studies – Universities (Solar , Wind generator Modeling, Validations), Green Energy Impact / Integration Studies (Wind, Solar, Biomass Generation connections impact studies)	Validation for solar, wind generator modeling on proto type devices in partnership with universities. Specific impact and integration studies of renewable generation as they relate to power quality, dispatch, protection and control, and communication.
Energy Research Initiatives ERI Program (Solar Generation Connections / Micro Grid Impact Studies)	Assessment of Solar Generation and Inverter devices as well as validation studies relevant to micro grid networks in partnership with ERI, industry partners and universities.

In addition to these studies, Hydro One participates in the Conference Board of Canada's Centre for Clean Energy in developing technologies which integrate clean-energy supply sources with end-users by means of selected "pathways". The work also examines the unique challenges facing Canadian utilities and advances the understanding of the transition to clean electricity in ways which are practical, profitable and sustainable.

Hydro One has partnered with the Toronto Atmospheric Fund (TAF) in a multi-year "GeoCity - Advancing Urban Geo-Exchange Energy" initiative to support development of a geothermal system of heat exchanges for heating and cooling in urban areas.

Hydro One also plans to participate with universities and industry to support development and demonstration of cryogenic energy storage technologies. This initiative promises to facilitate the integration of renewable distributed generation, maximizing the energy potential of such generation and minimizing investment in other assets.

Hydro One will continue to collaborate with EPRI on a Plug-In Hybrid Electric Vehicle ("PHEV") as a part of a trial and demonstration work in Hydro One's Smart Zone along with third party collaboration until the end of 2013. This work is critical in developing an empirical based understanding of the patterns of demand driven by the growing number of PHEVs as well as the potential adverse impacts on the distribution system and will help inform Hydro One and other utilities of the investments required to accommodate PHEVs.

Hydro One is also participating on a multi-year initiative entitled "NSERC Micro Grid Networks" to develop and demonstrate intelligent microgrid in the Canadian context. This initiative is supported by the Natural Sciences and Engineering Research Council of Canada (NSERC). Hydro One is participating in collaboration with 25 partners from governments, agencies, universities, and research companies across Canada. The initiative focuses on the challenges related to operation, control, protection, communication, monitoring, optimization and the regulatory issues of intelligent microgrids.

6.0 SUMMARY

Hydro One is facing replacement of aging assets and the need to establish new standards now

In the coming years, there will be an accelerated rate of asset replacement on the distribution system due to aging assets. Without new standards and designs, Hydro One will replace these assets with existing standards and "old" technology. This equipment will be on the system for up to 50 years or more. It is important that Hydro One has OM&A funding in 2013 to develop new standards and designs that will enable the replacement of assets with "tomorrow's" technology.

Hydro One is sharing information with other LDCs and the Board

As part of its Smart Grid work, Hydro One participates in various Ministry/IESO/OEB sponsorship initiatives, e.g., Smart Grid Forum, Smart Grid Working Group (EB-2011-0004) and other working groups. Hydro One has also launched a working group comprised of a number of

LDC project managers engaged directly in the actual implementation of smart grid applications and initiatives for their respective LDC. This working group provides a forum to discuss and share information on implementation challenges associated with the various smart grid pilot projects being undertaken by the LDCs.

Going forward, Hydro One intends to discuss and cooperate with the Board in the establishment of an on-line repository of pertinent smart grid study and demonstration project information and reports (subject to confidentially agreements or other restrictions) in conformance with the OEB guidelines contained in EB-2009-0397 ("Filing Requirements: Distribution System Plans – Filing under Deemed Conditions of Licence", March 25, 2010). The sharing of this information will benefit the Board and other LDCs in the development of the smart grid across Ontario. By delaying the implementation of Release 2, Hydro One will be unable to provide new insights and lessons learned to other LDCs which could raise the cost of their own programs.

Why OM&A Expenditures are Needed in 2013

Hydro One has been executing the Smart Grid plan that was approved by the Board in EB-2009-0096. Phase 1 of the project created newly installed systems that now need to be maintained and require incremental OM&A. It is important for Hydro One to continue executing its Smart Grid program. Phase 2 of the project will deliver additional DG integration capability, operational benefits for the utility and conservation benefits to our customers. Stopping the project now will create unnecessary costs and delay benefits to the customers. For Hydro One to meet all of the business objectives laid out in its Smart Grid plan, it is also important that it continue the Smart Grid Studies it is participating in with other institutions. The technologies validated in these studies are important to the next releaseas of the ADS project and deferring this work will delay the implementation of Hydro One's Smart Grid plan.

Customer Density and Distribution Service Costs

A Report Prepared for Hydro One Networks, Inc. by London Economics International LLC and PowerNex Associates Inc.

November 11th, 2011

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Executive Summary

London Economics International LLC ("LEI") and PowerNex Associates Inc. ("PNXA") were engaged by Hydro One Networks, Inc. ("HONI") to study the relationship between customer density and distribution service costs. This report provides a summary of the analysis that was conducted as well as observations and conclusions regarding HONI's existing rate classes and density weighting factors.

The study was initiated in response to a direction from the Ontario Energy Board ("OEB") requiring HONI to provide a detailed analysis on the relationship between density and cost allocation. The OEB also noted that consideration of alternative density weighting factors and descriptions and criteria for alternative rate structures should be included in the study.

This engagement had three specific objectives: (i) evaluate the relationship between customer density and distribution service costs; (ii) assess whether HONI's existing density based rate classes and density weighting factors appropriately reflect this relationship; and (iii) consider, qualitatively, the appropriateness and feasibility of establishing alternative customer class definitions. The first objective was the primary focus, as feedback from stakeholders suggested that understanding the relationship between density and cost of service was necessary before being able to begin to assess the reasonableness of the existing rate classes and cost allocation. The second and third objectives utilize the results of the analysis that was conducted to address the first objective.

<u>I. Evaluation of the Relationship between Customer Density and Distribution Service Costs</u>

The first objective was achieved through an econometric analysis of operating area level data and a direct cost assignment analysis of a selection of sample areas chosen by LEI and PNXA from across HONI's distribution service territory.

The econometric study analyzed operations, maintenance, and administrative costs ("OM&A") and a proxy for capital costs associated with 48 operating areas within HONI's distribution service territory. The purpose of the analysis was to determine whether or not there is a statistically significant relationship between distribution service costs and customer density over a five year period from 2006 to 2010, correcting for other factors such as number of customers, volume of energy delivered etc. As shown in Figure ES1, the estimated coefficients for customer density, in all four of the models considered, are negative and robust.[1] The coefficients represent the estimated sensitivity (or elasticity) of costs to changes in customer density, and the negative sign confirms that costs increase as customer density decreases.

1 In statistics terms, this is determined when a coefficient is statistically different from zero at the 95 percent confidence level.

Figure ES1: Estimated Density Coefficients

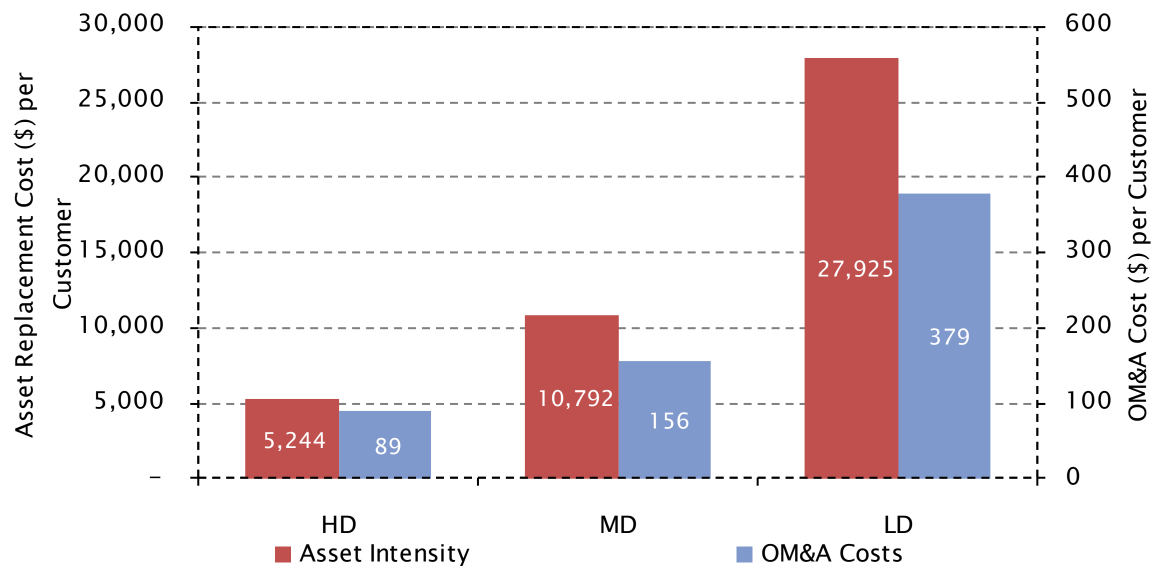
Costs Modeled in Econometric Model	Density Measure	Estimated Coefficient	95 Percent Confidence Interval	
			Low	High
OM&A	$CD_{ciircuit-km}$	-0.299	-0.368	-0.23
OM&A	CD_{km^2}	-0.100	-0.124	-0.076
OM&A and Capital Proxy	$CD_{ciircuit-km}$	-0.121	-0.349	-0.225
OM&A and Capital Proxy	CD_{km^2}	-0.287	-0.151	-0.092

Source: LEI and PNXA analysis

In the direct cost assignment analysis, 62 sample areas were selected from 11 operating areas across HONI's distribution service territory. The sample areas were selected to represent three levels of density, high, medium, and low (referred to as "HD", "MD", and "LD" respectively in the figures in this report), as well as to capture a representative range of operating conditions. The purpose of the direct cost assignment study was to analyze the cost to provide service to customers over a broader spectrum of customer densities than exist at the operating area level. OM&A costs were directly assigned to the sample areas using "assignment factors" that reflect engineering practices and utility operations. Capital costs (i.e., non operating costs) were also taken into consideration through an "asset intensity" calculation for each sample area. Asset intensity was defined as the replacement cost of the assets serving a sample area divided by the total number of customers contained within that sample area.

The direct cost assignment analysis confirmed that there is an inverse relationship between customer density and distribution service costs – consistent with the econometric study results. As shown in Figure ES2, the mean directly assigned OM&A cost and asset intensity (together the "assigned costs") increase as the customer density in the sample areas decrease. The mean of the assigned costs for each group of low-, medium-, and high-density sample areas were also shown to be statistically distinct at a 99 percent confidence level.

Figure ES2: Comparison of Sample Area Average Costs



Source: LEI and PNXA analysis

Both the econometric analysis and the direct cost assignment analysis established that there is a statistically significant relationship between customer density and distribution service costs. In both studies, distribution service costs were shown to decrease as the customer density of on operating area and/or a sample area increased.

II. Assessment of HONI's Existing Rate Classes and Density Weighting Factors

The second objective of the study was to assess whether HONI's existing density based rate classes and density weighting factors appropriately reflect this relationship. LEI and PNXA considered three specific elements of HONI's existing rate structure: (i) the use of customer density as a differentiator between the rate classes, (ii) the total number of density based rate classes, and (iii) the density weighting factors used in HONI's OEB-approved cost allocation model ("CAM").

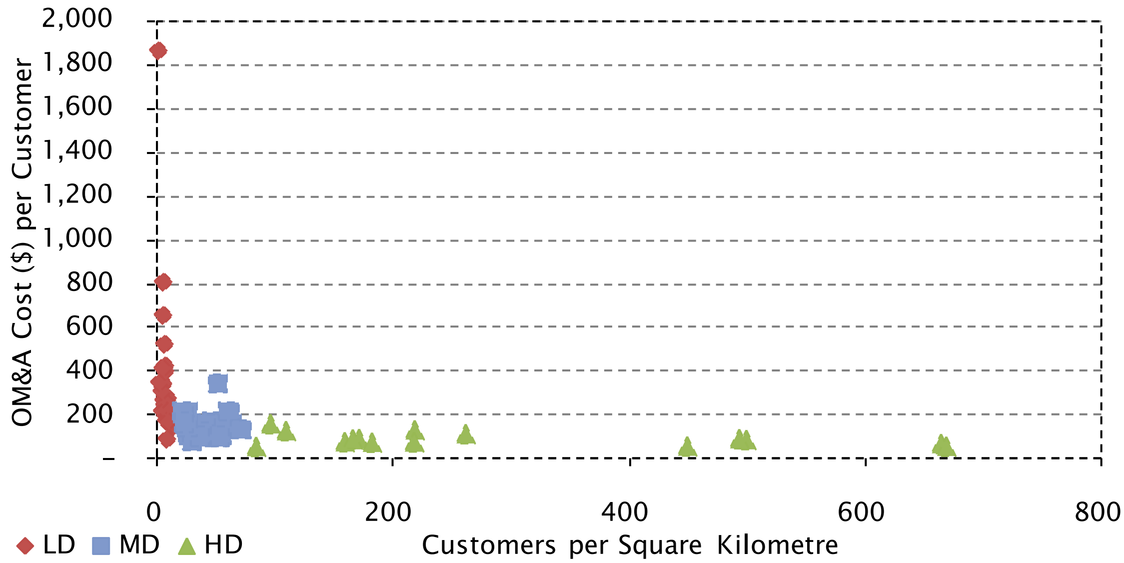
The results of the econometric and direct cost assignment analysis demonstrate that the cost to serve groups of customers that have different densities is in fact different. As such, on the basis of cost-causation principles it is appropriate for HONI to use rate classes that are differentiated based on customer density.

Based on the fact that the mean assigned costs for the three density level sample area groups were shown to be statistically distinct, it is appropriate for HONI to use three density differentiated rate classes (a low, medium, and high).

Figure ES3 (OM&A) and Figure ES4 (asset intensity) illustrate the relationship between the assigned per customer costs and the customer density for each of the samples areas. The two graphics reveal very similar patterns; the variability of the assigned costs decreases as density increases. The variability of the assigned costs within a given density group (high, medium, low) can be taken to represent the degree of cross-subsidisation that could potentially exist. Variability in the assigned costs is representative of the range of costs associated with serving individual customers in a group or class. As the range increases, or widens, the average cost to serve may remain constant, however, the low-cost customers provide a larger subsidy to the high-cost customers. Conversely, as the range decrease, or tightens, the subsidy diminishes.

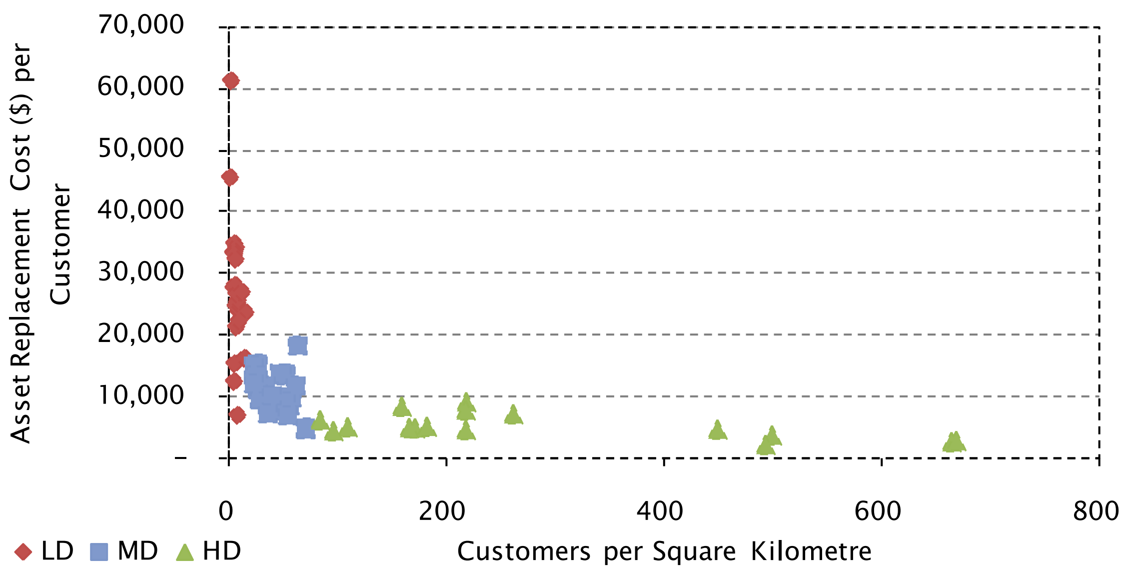
There is limited variability in the high-density sample area assigned costs. While there is more variability across the medium-density sample areas than across the high-density sample areas, the level of variability in the former is still rather limited. There is considerably more variability in the assigned costs for the low-density sample areas. This suggests that there may be a greater degree of cross subsidization within HONI's lowest-density rate class.

Figure ES3: Relationship between Assigned per-customer OM&A Costs and Customer Density



Source: LEI and PNXA analysis

Figure ES4: Relationship between Asset Intensity and Customer Density



Source: LEI and PNXA analysis

The direct cost assignment results present the most appropriate window through which to address the question of whether HONI's existing density weighting factors accurately reflect the relationship between customer density and cost of service, as established by the results of this study. LEI and PNXA chose to assess the reasonableness of the existing density weighting factors based on the impact they have on the allocation of costs in HONI's CAM.

Although the direct cost assignment analysis and HONI's CAM have different starting points and assumptions for the assignment/allocation of costs, comparisons can be made. Figure ES5

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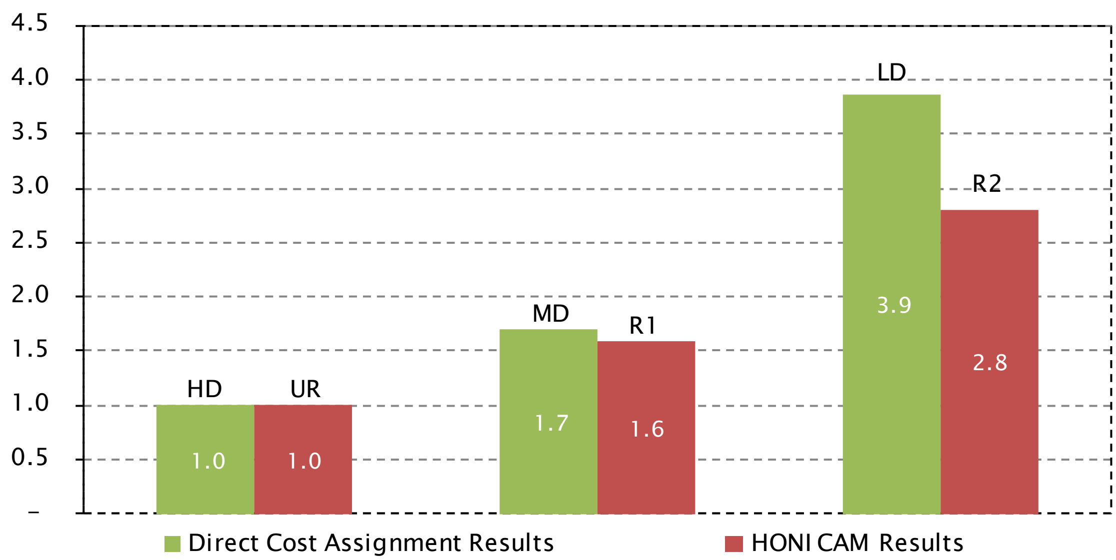
illustrates the ratio of the combined assigned costs between the high-, medium-, and low-density sample areas and the ratio of per-customer costs allocated to the existing HONI year round residential rate classes (UR, R1, and R2).[2]

The ratios are calculated relative to the highest-density group or rate class hence both the high-density sample area and UR ratios are equal to one. The ratios between the per-customer allocated costs for HONI's existing year round residential customer classes are directionally consistent and of similar magnitude to the ratios obtained in the assigned costs for the low-, medium-, and high-density sample areas. As is discussed in detail in the body of this report, the low-density sample areas likely overstate the average density of HONI's distribution service territory containing R2 customers. Whereas, the high-density sample areas likely understate the density of HONI's distribution service territory containing UR customers. As such, the ratios between the sample area group means are likely to be lower than they would otherwise be if the density used in the study was defined in the same manner as the density of the existing HONI rate classes. Hence, the results of direct cost assignment analysis suggest that the current density weighting factors likely understate the difference between the costs to serve low- and high-density customers.

Figure ES5: Comparison of Output from HONI Cost Allocation Model to Adjusted Ratios of Average Sample Area Costs



Source: LEI and PNXA analysis

Based on a review of the 11 operating areas included in the direct cost assignment analysis, the density of HONI's service territory containing seasonal customers is expected to fall somewhere between that of service territory containing the R2 and R1 customers. Similarly, the density of

2 Note that the ratios presented in Figure ES5 are not based directly on the mean sample area assigned costs presented in Figure ES2. Adjustments have been made to the mean sample area assigned costs to take into account excluded OM&A costs and to combine the OM&A and asset intensity results. A detailed description of these adjustments is provided in Section 5.2 in the body of this report.

HONI's service territory containing non-urban general service customers (the GSe and GSd rate classes) is expected to fall somewhere between that of the service territory containing the R2 and R1 customers, whereas, the density of HONI's service territory containing urban general service customers (the UGe and UGd rate classes) is similar to that of the service territory containing UR customers.

III. Alternative Rate Structures

The third objective of the study is addressed through a qualitative discussion of a number of alternative rate structures, including: adjustments to HONI's current rate structure; adopting the use of municipal boundaries; and province-wide or regional postage–stamp rates.

Based on the results of this study, a wholesale change to HONI's existing rate class definitions is not necessary. LEI and PNXA have identified certain adjustments that could be made, however, any change will result in winners and losers and care will need to be taken to avoid instances of "rate shock". While other rate class definitions were considered (i.e., municipal boundaries or regional rates), the move to such a design is a longer-term decision that LEI and PNXA suggest should be considered in the context of a broader provincial dialogue.

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1 Introduction

London Economics International LLC ("LEI") and PowerNex Associates Inc. ("PNXA") were engaged by Hydro One Networks, Inc. ("HONI") to study the relationship between customer density and distribution service costs. This report provides a summary of the analysis conducted as well as observations and conclusions regarding HONI's existing rate classes and density weighting factors.

This report contains six sections, in addition to this introduction:

- Data Sources;
- Summary of the Econometric Analysis;
- Summary of the Direct Cost Assignment Analysis;
- Implications for HONI's Current Tariff Design;
- Discussion of Alternate Rate Structures; and
- Conclusions and Recommendations.

Three appendices to this report provide additional details on the econometric analysis; background information on distribution systems; and additional details on the direct cost assignment analysis, including maps of the operating areas and sample areas selected and individual sample area results.

1.1 Objectives

LEI and PNXA had three specific objectives.

- **Objective 1**: Evaluate the relationship between customer density and distribution service costs.
- **Objective 2**: Assess whether HONI's existing density based rate classes and density weighting factors appropriately reflect this relationship.
- **Objective 3**: Consider, qualitatively, the appropriateness and feasibility of establishing alternate customer class definitions.

The first objective was the primary focus, as feedback from stakeholders suggested that understanding the relationship between customer density and distribution service cost was necessary before being able to begin to assess the reasonableness of the existing rate classes and density weighting factors.

1.2 Phased Approach and Stakeholder Consultation

LEI and PNXA were engaged by HONI in two phases. The first phase of the engagement was a "scoping" phase. LEI and PNXA utilized this phase to develop and refine the proposed study methodology. The second phase of the engagement was an "implementation" phase. LEI and PNXA utilized this phase to implement the study methodology.

The first phase consisted of four main tasks. The first task was to review background material relevant to HONI's distribution rate design, including its existing CAM and recent regulatory filings. The second task involved the collection and analysis of HONI and third-party data to understand the extent of data available to support the detailed study methodology. The third task involved the development and validation of a detailed study methodology. The fourth task was to present the proposed study methodology to stakeholders.

The stakeholder information session was held on March 22, 2011, at HONI's offices in Toronto, Ontario. Stakeholders provided a number of comments, which have been incorporated into the methodology discussed in this report. The presentation delivered by LEI and PNXA, and notes from the stakeholder session are available online from HONI's website.[3]

The study also takes into consideration comments from the September 8, 2010, stakeholder session in Toronto, Ontario, in particular feedback regarding the need to understand the density-cost relationship before deciding what to do about rate classes.[4]

1.3 Ontario Energy Board Rulings

The Ontario Energy Board ("OEB") issued its Decision with Reasons in regards to HONI's 2008 distribution rate application on December 18, 2008. In this decision, HONI was directed to

> *"provide a more detailed analysis on the relationship between density and cost allocation to the Board. [The analysis] should consider whether the number of Residential and General Service customer classes in the new class structure is adequate, and whether the customer class demarcations approved in this Decision offer the best reflection of cost causation. The study should include consideration of alternative density weightings, with descriptions and criteria for comparing alternatives".*[5]

In HONI's 2010/11 rate application (EB-2009-0096), HONI submitted a preliminary report that conceptually explored the relationship between density and cost allocation.[6] The study did not attempt to address the relationship quantitatively. The Decision with Reasons issued by the OEB directed HONI to comply with the prior direction on this issue and noted that

> *"The [OEB] expects [HONI] to work cooperatively with the parties but leaves it to [HONI's] discretion to determine how best to conduct the study taking into consideration timing, feasibility and cost."*

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3 Presentation: <http://www.hydroone.com/RegulatoryAffairs/Documents/EB-2011-0215/Dx%20Stakeholder%20Cost%20Density%20LEI-PNXA%20Presentation.pdf>
Session Notes: <http://www.hydroone.com/RegulatoryAffairs/Documents/EB-2011-0215/Density%20Stakeholder%20Consultation%20Meeting%20Notes.pdf >

4 Session Notes: <http://www.hydroone.com/RegulatoryAffairs/Documents/EB-2011-0215/Density%20Stakeholder%20Consultation%20Meeting%20Notes.pdf>

5 OEB. "In the matter of an application by: Hydro One Networks, Inc. 2008 Rates - Decision with Reasons". (EB-2007-0681). Toronto: December 18, 2008.

6 Elenchus Research Associates. "Principles for Defining and Allocating Costs to Density-Based Sub-Classes". Toronto: 2009.

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This study's methodology, developed by LEI and PNXA, serves to meet the requirements of the OEB decisions and reflect stakeholder input. In particular, the study evaluates the relationship between customer density and distribution service costs, and assesses whether the existing rate classes and density-based weighting factors reflect this relationship. Furthermore, recognizing that there is no unique best solution in rate design, this report discusses the appropriateness and feasibility of establishing alternative customer class definitions.

1.4 Structure of Analysis

The methodology LEI and PNXA used to complete its analysis, which was presented to stakeholders on March 22, 2011, has two distinct components: an econometric analysis and a direct cost assignment analysis.

The econometric analysis provides valuable insights into the relationship between customer density and distribution service costs at the operating area level. As such, a significant amount of the variability in customer density that is observed across HONI's service territory is not available in this type of analysis as it is averaged out.

On the other hand, the direct cost assignment method is able to drill down to a much greater level of detail and analyze smaller sample areas with a wider range of observed customer densities than the econometric analysis. Furthermore, the results of the direct cost assignment analysis, as discussed in Section 5 of this report, are useful in addressing the second objective of this engagement.

The two methods offer unique but complimentary ways of analyzing the relationship between customer density and distribution service costs. The results of each were not known at the time the methodology was developed and the intention was always to utilize both, together, to support the conclusions and recommendations in this report.

2 Data Sources

HONI collects and maintains an extensive amount of data on its operating costs, and the characteristics of the customers and regions it serves. This data is comprehensive, consistent, and therefore very useful for the econometric or direct cost assignment analyses.

This study relied upon data from four primary sources currently available within HONI. Brief descriptions of the databases and type of data contained within each are provided below. Further discussion of the specific datasets used for each of the analyses is provided in Sections 3.2 and 4.2 of this report.

SAP Enterprise Resource Planning System

The SAP Enterprise Resource Planning System ("SAP") is used by HONI to track financial information on fixed assets, work programs (i.e., OM&A and capital expenditures, or "CAPEX"), and inventory. This includes the acquired value and accumulated depreciation of assets.

Customer Information System

Customer account details, including energy consumption and connectivity are maintained within the Customer Information System ("CIS"). HONI's CIS contains all customer related information, including usage history, rate class, customer and service address, meter number, and customer number.

Geographic Information System

The Geographic Information System ("GIS") is a comprehensive special database of HONI's physical assets (e.g., poles, transformers, feeders, distribution stations, meters etc.).[7] The GIS contains a number of other datasets including: municipal boundaries; roads and major highways; neighbouring local distribution company ("LDC") boundaries; and topography. The recent availability of the GIS data was integral to LEI and PNXA completing this study.

Outage Response Management System

The Outage Response Management System ("ORMS") is HONI's trouble call management database. The ORMS contains detailed information on service calls including: records of events (with and without customer interruptions), date, location, and type of event (e.g., equipment failure, planned outages, etc.).

[7] Currently, 93 percent of distribution poles and 90 percent of distribution feeders are identified in the GIS.

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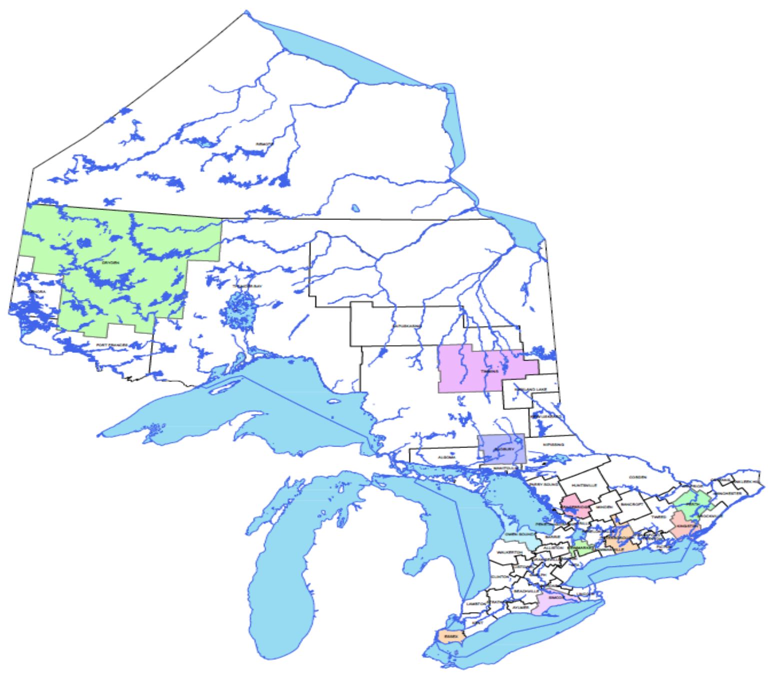
3 Summary of Econometric Analysis

As mentioned in Section 1.4, one component of the methodology was an econometric analysis of operating area level data. LEI and PNXA carried out an econometric analysis of OM&A and a proxy for capital costs associated with the 48 operating areas within HONI's distribution service territory. The purpose of this analysis was to demonstrate whether or not there is a statistically significant relationship between distribution service costs and customer density, correcting for other factors.

3.1 Introduction

One definition of econometrics (the science of econometric analysis) is that it is "the process of fitting mathematical economic models to real-world data".[8] In the context of this study, LEI and PNXA developed and estimated an economic model to explain the variability in distribution service costs across the operating areas within HONI's service territory, over a five year period.

Figure 1: Operating Areas in HONI's Distribution Service Territory



Note: The highlighted operating areas are those included in the direct cost assignment analysis. The econometrics analysis included data for all operating areas
Source: HONI

The functional form of the econometric model, in this case a "cost function", is chosen based on theory. The unknown parameters embedded within the cost function are then estimated using regression analysis.

[8] Stock, J. and M. Watson. *Introduction to Econometrics*. New York: Pearson Education, Inc. Book.

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Regression analysis includes techniques for modeling and analyzing the relationship between independent (causal or explanatory) variables and dependent variables. More specifically, regression analysis provides insight into how the value of a dependent variable changes when one of the independent variables changes (assuming all other independent variables are held constant). Econometric analysis is a commonly accepted practice within utility regulatory proceedings. While certain elements of the analysis can lead to contention (for example, the reasonableness of the underlying data, choice of parameters, model definition, etc.), the approach and the methods behind the concept are generally well accepted.

In Ontario, econometric analysis was accepted by the OEB as part of the second- and third-generation incentive rate mechanism ("2GIRM" and "3GIRM", respectively) proceedings.[9] In these proceedings it was used to benchmark utility cost performance and establish relative productivity trends across peer groups. There are also numerous examples from other jurisdictions across North America where econometric analysis has been relied upon in the context of distribution rate design.[10]

In this study, LEI and PNXA relied entirely on data pertaining to a single utility, HONI. As will be discussed in the next section, this approach goes a long way to eliminating one of the more common concerns with inter-utility cost studies.

3.2 Data for Econometric Analysis

A common point of contention that has arisen in Ontario around the use of econometric analysis, generally speaking, is the potential for inconsistent datasets as a result of different reporting standards across utilities. The OEB has taken steps to standardize reporting requirements in Ontario, but there are still areas where data is limited and concerns can arise (e.g., the treatment of shared services, different capitalization rules, etc.). The use of data exclusively from HONI eliminates this concern. LEI and PNXA understand that HONI maintains consistent data reporting and tracking standards across its entire service territory.

The data that LEI and PNXA relied upon for the econometric analysis comes from three primary systems within HONI, namely SAP, GIS and CIS. For the purposes of this econometric analysis, the operating area name acts as a primary key to link data from each of the independent data systems.

The majority of this data is available and was compiled at the operating area level.[11] The exceptions were:

9 EB-2006-0089 and EB-2007-0673

10 An abridged list of examples include: a study performed by Power Systems Engineering for the Illinois Citizens Utility Board, which evaluated the cost performance of Ameren Illinois Company; in 2009, Oklahoma Gas & Electric conducted a benchmarking study to gauge operating and maintenance cost performance; and in 2003, Ameren Missouri provided evidence in support of its cost performance using econometric techniques.

11 For some operating areas (e.g., Thunder Bay) data was compiled by aggregating sub-regions (e.g., Thunder Bay, Marathon and Geraldton).

- vegetation management costs, which are tracked on a feeder basis;
- distribution station costs, which are tracked at the provincial level;
- a handful of other OM&A work program costs that are also tracked at the provincial level;
- Customer Care costs, which are tracked at the provincial level; and
- Shared Services and general and administrative costs which are also tracked at the provincial level.

HONI provided datasets for the past five years (2006 through 2010) for the 48 operating areas.

Figure 2: Granularity of HONI Data

Provincial	Operating Area	Feeder
• Distribution stations OM&A and CAPEX • Shared services • Customer care • Operations	• Number of customers • Energy consumption • Lines OM&A and CAPEX • Acquired asset value • Cumulative depreciation • Asset counts • Geographic data	• Vegetation management

<u>Number of Customers</u>

HONI provided data from the CIS consisting of the number of customers in each of the rate classes in 2006 to 2010, by operating area.

<u>Energy Consumption</u>

Energy consumption data was provided by HONI for each of the existing rate classes within each operating area from 2006 through 2010.

<u>OM&A Costs</u>

OM&A costs within HONI are tracked through work programs. The two prominent sets of programs within the distribution company are lines and stations. The annual OM&A cost for each year and for each operating area was calculated as the total of the Lines OM&A, Stations OM&A, and vegetation management costs, the latter being a subset of Lines OM&A but tracked independently.

The majority (approximately 90 percent) of the Lines OM&A costs are naturally tracked by HONI at the operating area level, including costs associated with storms and trouble calls. Rather than assigning provincial-level costs to the operating areas, Lines OM&A costs that are tracked at the provincial level were excluded from the analysis.

Stations OM&A costs are all tracked at the provincial level. As such, total provincial stations OM&A costs were disaggregated to the operating areas based on the number of distribution stations within each operating area.

Vegetation management costs are reported within HONI at the distribution-feeder level. HONI provided details on the specific feeders contained within each operating area and the annual vegetation costs associated with each feeder over the past ten years. Given that vegetation costs can vary from year to year, LEI and PNXA calculated a ten-year levelized cost for each feeder.[12] The levelized feeder cost was calculated by inflating all of the annual feeder costs into 2010 dollars, using actual values of the Canadian consumer price index, and then taking an average. The feeder level costs were then aggregated to produce a total cost for each operating area in 2010 dollars. The levelized operating area cost was then adjusted for inflation to determine the annual levelized cost in nominal 2006, 2007, 2008, and 2009 dollars. This approach results in a smooth vegetation management cost for each year within a given operating area, while at the same time maintains the variability in vegetation management costs across different operating areas.

Econometric studies are based on observations of data from real world situations. Minimizing the number of adjustments to the data typically results in more robust and defensible results. With the exception of distribution stations OM&A and CAPEX, LEI and PNXA did not allocate provincial level costs to the operating areas for the econometric analysis. Hence, the majority of customer care costs, shared services, and operations expenses which are all tracked at the provincial level were excluded.

Total Capital Costs

There are a number of possible measures of "capital costs" for a distribution utility, for example both the net book value ("NBV") and replacement cost of all installed assets are plausible proxies.

For the purpose of this econometric study, LEI and PNXA developed an estimate of the annual depreciation and the return on regulated asset base associated with each operating area in each year (a "Capital Proxy"). This approach is reflective of the annual capital-driven costs that are embedded in HONI's distribution revenue requirement.

To develop this Capital Proxy, LEI and PNXA used data from SAP on the acquired value and the accumulated depreciation of assets in each operating area. SAP tracks groups of similar assets in an operating area rather than the individual assets themselves. It also maintains records of the year in which groups of assets were placed into service (asset vintage). The difference between the acquired value and accumulated depreciation yields the net book value for each asset vintage.

12 The vegetation management cost data reflected the historical ten years average vegetation management cycle across HONI's service territory.

The capital cost measure for each operating area was calculated as the average of the end of year and beginning of year NBV, which takes into account annual capital additions in each year, times the OEB approved weighted average cost of capital ("WACC") for HONI in each year, plus the total depreciation taken in the year.

Equation 1

$$Capital\ Proxy = \mathrm{WACC} * \frac{\mathrm{NBV_{EOY}} + \mathrm{NBV_{BOY}}}{2} + Annual\ Depreciation$$

Other Asset and Geographic Data

HONI also provided additional data on the total number of assets within the operating areas. Specifically, and critical to this study, this included the total length of all feeders within the operating area and the physical size of the operating area. Additional data such as the number of distribution stations, number and rating of transformers was also made available.

Customer Density

LEI and PNXA calculated the customer density of each operating area from the customer count data and the asset and geographic data provided for each operating area for each year. Two parameters were calculated: (i) the total number of customers per square kilometre of the operating area and (ii) the total number of customers per circuit kilometre (including overhead, underground, and submarine feeders) of feeders in the operating area.[13] The customer densities represent an average for each of the operating areas.

Charts summarizing the operating area level data collected and used in the econometric analysis are provided in Appendix A.

3.3 Functional Form

The functional form used in this analysis is similar to those used in other econometric analysis performed in Ontario in relation to distribution utility costs. It is the same functional form that was used by Pacific Economics Group in its work for the OEB as part of the 2GIRM and 3GIRM proceedings.[14,15] The chosen functional form is "quadratic" and has the following general formula.[16]

13 The total size of the operating area and the total length of conductor were only available for 2010.

14 Pacific Economics Group. "Second Generation Incentive Regulation for Ontario Power Distributors." 2006.

15 Pacific Economics Group. "Sensitivity Analysis on Efficiency Ranking and Cohorts for the 2009 Year: Update." 2008.

16 The "double log" form is one of the simplest functional forms used when analyzing utility costs, as it assumes constant economies of scale. The double log form works with smaller datasets. The quadratic form is an expansion of the double log form. The quadratic form contains exponential terms which adjust for varying economies of scale and scope and non-linear relationships between dependent and independent variables. Typically a larger data sample is required when using this form. The "translog" form is a further expansion of

Equation 2

$$\ln C = a_0 + \sum_i a_i \ln Y_i + \sum_j a_j \ln W_j + \sum_k a_k \ln Z_k + a_t T + \frac{1}{2}\left[\sum_i b_i \ln Y_i \ln Y_i + \sum_j b_j \ln W_j \ln W_j\right] + \varepsilon$$

Here, "Y_i" denotes a variable that quantifies output and "W_i" denotes an input price. The "Z" variable denotes additional business conditions, "T" is a trend variable, and "ε" denotes the error term. The "a" and "b" terms represent the estimated coefficients. Note, that because each of the independent and dependent variables is represented as a natural logarithm ("ln") the coefficients are "elasticity" estimates.[17]

LEI and PNXA analyzed two specific cost functions, one where C denotes OM&A costs only and the other where C denotes OM&A and the Capital Proxy.

3.4 Included Variables

The refining of the cost function was an iterative process, where a number of different model specifications were tested. In determining which variables to include in a final model, economists weigh concerns such as the sign of the estimated coefficients, the statistical significance of the coefficients, and the overall "fit" of the regression.

It is important that the sign of the coefficients in the model be consistent with logical expectations. It is also important that the estimated coefficients be statistically significant. Statistically significant implies that with a high degree of confidence the coefficient is non-zero. Fit is most commonly measured by the "R-squared" of the regression -- a value from zero to one, with one being a perfect fit. The R-squared term measures the magnitude of the error between the predicted values and the actual values.

In addition, in order to obtain robust estimated coefficients, it is important to utilize independent variables that have a limited degree of multicollinearity. Multicollinearity occurs when one or more of the independent variables are correlated. Multicollinearity causes erratic results, as the model is not able to uniquely isolate the impact of the independent variables on the dependent variable.

The four parameters determined to produce the best fit cost function were customer density ("CD"), number of customers ("N"), energy density ("ED"), and a time, or trend, variable ("T"). Energy density is the average consumption per customer in each operating area. No input

the quadratic form. Translog functions allow for interaction between independent variables. The form also takes into account varying economies of scale and scope. The translog form is generally more flexible in terms of describing costs than the quadratic or double log functions. The translog form also requires a larger data sample than the quadratic or double log functional forms.

17 Elasticity represents the ratio of change of one variable with respect to another. It is used to measure the responsiveness of the dependent variable to changes to an independent variable.

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prices were considered as the input prices within HONI are generally the same across the operating areas. Number of customers is an output variable, thus the final model also includes its square term ("NN"). The inclusion of the square term allows for the modeling of a non-linear relationship between cost and number of customers. This choice of variables is consistent with other econometric analyses where customer density is considered as an independent variable.[18,19]

It should be noted that other operating area level data was considered for the analysis including asset age, net asset value, assets counts (distribution stations, transformers), conductor length, average customer distance from the service centre(s) and geography. The inclusion of these variables did not improve the results of the regression. The inclusion of additional variables resulted in erratic model behaviour, such as sign changes and lack of significance of the estimated coefficients. This is likely due to the overall size of the sample and the fact that many of the characteristic variables are correlated.

As will be discussed in Section 3.6, the simpler model specification produced robust and consistent results.

3.5 Estimation Procedures

Ordinary least squares ("OLS") is a method for estimating the unknown variables in a linear regression model. An OLS model seeks to minimize the sum of the squared differences between the observed values and the predicated values as determined by the regression. OLS is commonly used in econometric and engineering applications. OLS models typically work well when multicollinearity is minimized and when the model errors are homoskedastic.[20] Generalized least squares ("GLS") is similar to OLS, except it is typically applied when the variances of the observations are unequal (i.e., there is heteroscedasticity), or when there is a certain degree of correlation between the observations.

LEI and PNXA utilized a modified GLS algorithm to estimate the regression coefficients.

3.6 Results

The following four figures summarize the results of the regression analysis. Figure 3 and Figure 4 show the results of the model which considered OM&A costs only with density measured as number of customers per circuit kilometre and number of customers per square kilometre, respectively. Since a logarithmic form was used, the estimated coefficients are a measure of elasticity. The t-statistic is the ratio of the parameter estimate and the standard

18 Lawrence, Denis. Meyrick and Associates. "Efficiency Comparisons of Australian and New Zealand Gas Distribution Businesses Allowing for Operating Environment Differences." 2007.

19 Farsi, M.; Filippini, M.; Plagnet, M.; Saplacan, R..Centre for Energy Policy and Economics, Swiss Federal Institutes of Technology. "The Economies of Scale in the French Power Distribution Utilities." 2010.

20 Homoskedasticity occurs when the variances of the error term is not correlated with one of the variables of the function. If the variances of the error term are correlated with one or more of the variables of the function, the error terms are said to be heteroskedastic.

error. With 240 observations, a t-statistic in excess of an absolute value of 1.96 suggests that the explanatory variable is statistically significant at the 95 percent confidence level.

Figure 3: Econometric Parameter Estimates (OM&A Costs Model with Customer per Circuit Kilometre)

Number of Observations:	240
R^2:	0.73
Sample Period:	2006-2010

Explanatory Variable	Parameter Estimate	T-Statistic
N	3.756	4.79
NN	-0.297	-3.83
$CD_{line-km}$	-0.299	-8.47
ED	-0.109	-3.31
T	0.021	2.22

Source: LEI and PNXA analysis

The estimated coefficients in both models are statistically different from zero at the 95 percent confidence level, and exhibit signs that are consistent with the fundamental understanding of the costs of a distribution utility. For example, the model results show that as the number of customers served increases, the OM&A costs are expected to increase. Also, as the average size of a customer increases, as measured by the energy density term, the model predicts that OM&A costs would decrease.

Figure 4: Econometric Parameter Estimates (OM&A Cost Model with Customer per Square Kilometre)

Number of Observations:	240
R^2:	0.73
Sample Period:	2006-2010

Explanatory Variable	Parameter Estimate	T-Statistic
N	5.072	6.65
NN	-0.426	-5.66
CD_{km2}	-0.100	-8.01
ED	-0.072	-2.07
T	0.018	1.95

Source: LEI and PNXA analysis

Figure 5 and Figure 6 show the results of the model that considered both OM&A costs and the Capital Proxy with density measured as number of customers per circuit kilometre and number of customers per square kilometre, respectively.

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Figure 5: Econometric Parameter Estimates (OM&A Costs and Capital Proxy Model with Customer per Circuit Kilometre)

Number of Observations:	240
R^2:	0.71
Sample Period:	2006-2010

Explanatory Variable	Parameter Estimate	T-Statistic
N	3.975	4.80
NN	-0.305	-3.80
$CD_{line-km}$	-0.287	-9.10
ED	-0.026	-0.61
T	-0.023	2.05

Source: LEI and PNXA analysis

In these models the estimated coefficient for the energy density term is not significantly different from zero at the 95 percent level. The estimated coefficients for the customer density variables remain negative and significantly different from zero at the 95 percent level.

Figure 6: Econometric Parameter Estimates (OM&A Costs and Capital Proxy Model with Customer per Square Kilometre)

Number of Observations:	240
R^2:	0.74
Sample Period:	2006-2010

Explanatory Variable	Parameter Estimate	T-Statistic
N	5.596	5.74
NN	-0.460	-4.93
CD_{km2}	-0.121	-7.94
ED	0.028	0.64
T	0.020	1.88

Source: LEI and PNXA analysis

The following table summarizes the estimated density coefficients and the 95 percent confidence intervals for the four models.

Figure 7: Estimated Density Coefficients

Costs Modeled in Econometric Model	Density Measure	Estimated Coefficient	95 Percent Confidence Interval	
			Low	High
OM&A	$CD_{ciircuit-km}$	-0.299	-0.368	-0.23
OM&A	CD_{km^2}	-0.100	-0.124	-0.076
OM&A and Capital Proxy	$CD_{ciircuit-km}$	-0.121	-0.349	-0.225
OM&A and Capital Proxy	CD_{km^2}	-0.287	-0.151	-0.092

Source: LEI and PNXA analysis

The results shown in Figure 7 indicate that for a fivefold increase in the number of customers per square kilometre (e.g. an increase from 5 to 25 customers per square kilometre), all else being equal, costs (both OM&A and capital) would be expected to decrease by 143.5 percent.

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To put the magnitude of the increase in density into perspective, in the direct cost assignment analysis the high-density sample areas were 6.8 times denser on average than the medium-density sample areas. The medium-density sample areas were 7.2 times denser on average than the low-density sample areas.

The 95 percent confidence interval of the density coefficient in all four models exclude zero. Thus the model demonstrates that customer density, regardless of how it is measured, is inversely related to distribution service costs. As customer density decreases, the cost to serve the same number of customers, all other factors being equal, would be expected to increase. The opposite also holds true where customer density increases, the cost to serve the same number of customers, holding all other variables constant, would be expected to decrease.

The first objective of this study was to analyze the relationship between customer density and distribution service costs. The econometric analysis confirms that there is a statistically significant relationship, and that as customer density increases cost generally decrease, all else held equal. With this understanding, the direct cost assignment analysis described in the next chapter of this report attempts to confirm or refute this relationship at a more granular sample area level within selected operating areas. The direct cost assignment analysis also aims to explore the magnitude of the density-cost relationship.

4 Summary of Direct Cost Assignment Analysis

4.1 Introduction

In the first phase of this engagement, the feasibility of a direct cost assignment analysis was investigated. The conclusion of that work established that such an analysis was feasible, and, when tested in one operating area, provided results which were considered by LEI and PNXA to be credible. In the second phase of this engagement, the direct cost assignment analysis was extended to 62 sample areas selected from 11 operating areas across HONI's distribution service territory.

The purpose of the direct cost assignment analysis was to investigate how the cost to serve customers over a broad range of customer densities varies. Sample areas were selected to represent three levels of density high, medium, and low (referred to as "HD", "MD", and "LD" respectively in the figures in this report), as well as to capture a representative range of the normal operating conditions that exist across HONI's service territory.

OM&A costs were directly assigned to the sample areas using a number of "assignment factors" that reflect engineering practices and utility operations. The assignment factors were selected based on an understanding of distribution system operations, types of assets, topology, and hence the principal drivers of cost.[21] This assignment of OM&A costs allowed for the calculation of a per-customer OM&A cost for each sample area.

The "asset intensity" was also calculated for each sample area, as a proxy for capital (non-operating) costs. Asset intensity was defined as the replacement cost of the assets serving a sample area divided by the total number of customers contained within that sample area.

4.2 Data for Direct Cost Assignment Analysis

The direct cost assignment analysis utilized a number of datasets from within HONI. A brief description of the major datasets collected is provided below.

- The number and length of distribution feeders, whether they pass through a sample area, and the length inside and outside each operating area and sample area.
- The number of customers in each sample area and operating area.
- The number of poles in each sample area and each operating area, including pole ownership (e.g., HONI-owned, Bell Canada owned, customer-owned, etc.) and type of pole mount (i.e., rock, earth, other).[22]
- The total number and type of assets (e.g., transformers, switches, regulators, capacitors, re-closers, meters, etc.) in each sample area and operating area.

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21 Background information on distribution systems and common terminology can be found in Appendix B.

22 It is quite common for utilities to share poles. HONI and Bell Canada have a pole sharing agreement in a number of locations across the province. Typically the owner of the pole is responsible for ongoing maintenance.

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- The geographic coordinates of customers, poles, and service centers in each sample area and operating area.
- The number of interruptions and non-interruptions resulting from both storm and non-storm related events for each operating area and each feeder.[23]
- OM&A costs for each operating area and provincial-level programs.
- The typical replacement cost of assets currently used across HONI's network.

4.3 Selection of Operating and Sample Areas

Operating areas were selected to be representative of the range of conditions across HONI's distribution service territory. The number of sample areas is important to assure the statistical significance of the results. Based on the preliminary results from the initial phase of the engagement, LEI and PNXA estimated that, at a minimum, 45 sample areas would likely be required to achieve a reasonable degree of confidence in the results.

4.3.1 Operating Area Selection

To provide for a broad coverage of HONI's service territory a total of 11 operating areas were selected: Bracebridge, Dryden, Essex, Kingston, Newmarket, Owen Sound, Perth, Peterborough, Simcoe, Sudbury, and Timmins.

HONI operates across diverse terrain with a large variation in environmental, geographic, and other operating conditions. The operating areas were chosen to ensure that they represent a material cross section of the actual conditions, customers, and geography of HONI's service territory. Figure 8 and Figure 9 illustrate the chosen operating areas and their location across the province. The operating areas selected, include three in the north, three in the southwest, three from the central part of the province, and two in the east. They include a blend of agricultural, forested, and urban areas. Furthermore, the operating areas were selected to represent diversity in terms of geology, the prevalence of storms, and overall size.

[23] Non-interruptions refer to trouble calls where a work crew was dispatched but customers did not suffer a loss of power.

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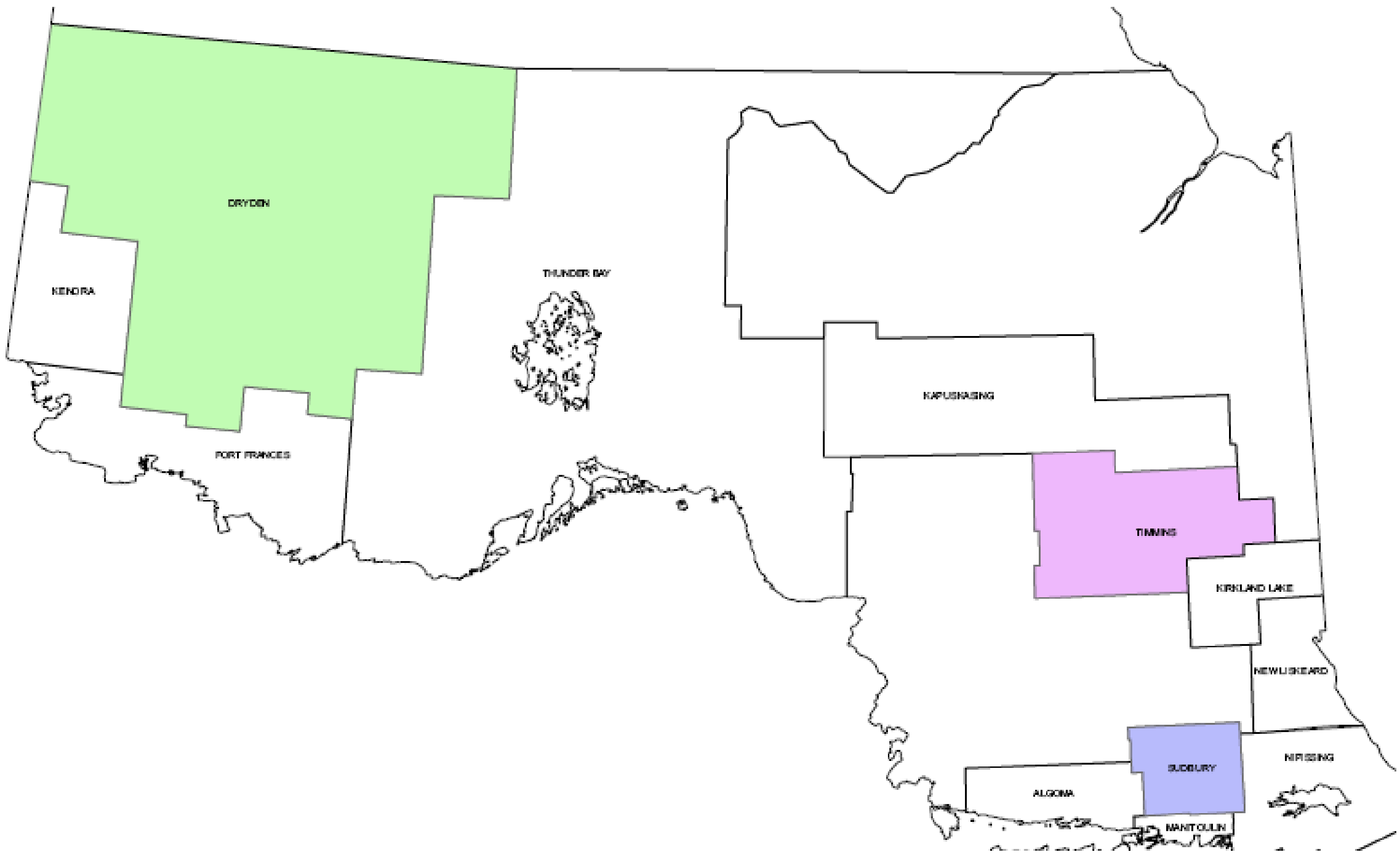
Figure 8: Operating Areas Selected from Northern Ontario



Source: HONI; LEI and PNXA analysis

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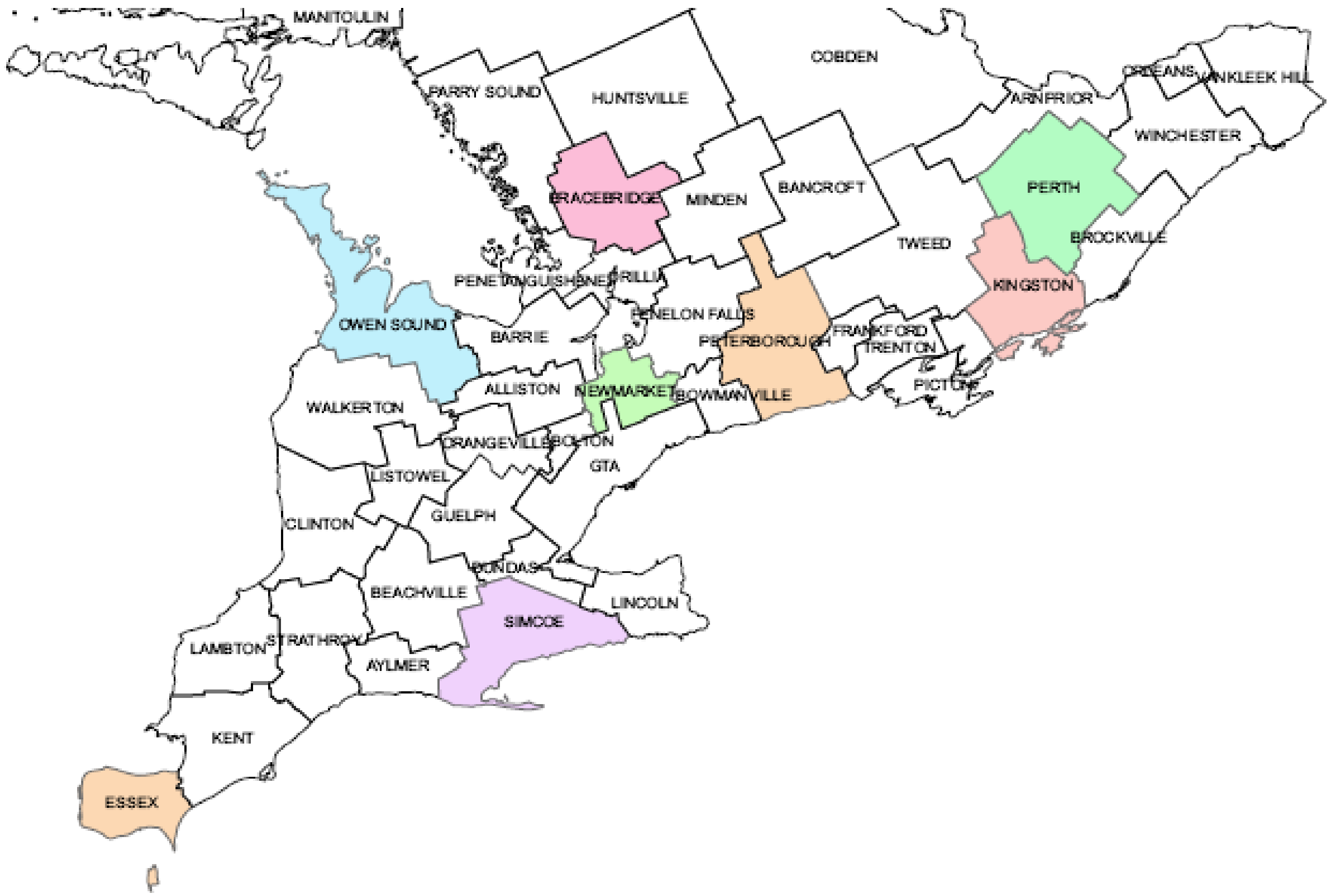
Figure 9: Operating Areas Selected from Southern Ontario



Source: HONI; LEI and PNXA analysis

4.3.2 Sample Area Selection

A total of 62 sample areas were selected; between four and seven from each of the 11 operating areas.

In order to test the hypothesis that there is a relationship between customer density and the cost to serve customers, sample areas having three distinct customer densities were defined. This was accomplished by using sample areas of approximately the same size and by selecting areas with varying numbers of customers. The selection of sample areas did not consider the existing rate classes or density definitions. When selecting the sample areas, LEI and PNXA followed the five general guidelines listed below:

- each sample area should be of a similar size, approximately 20 square kilometres;
- low-density sample areas should have between 100 and 200 customers;
- medium-density sample areas should have between 700 and 1,200 customers;
- high-density sample areas were found around any large "urban" concentration of customers within the operating area, resulting in sample areas with typically more than 2,000 customers.
- sample area boundaries should be selected to minimize the impact of network structure on the calculation of the assignment factors and/or asset intensity.

With respect to the last guideline, it was important to minimize the degree of judgment required to determine whether an asset served, or an outage affected, a given sample area.

The above criteria were formulated and used for the initial identification of potential sample areas. Additional low-density sample areas with fewer customers (i.e., less than 100) were also included to better capture the actual variability of customer density in rural areas.

The process of selecting operating areas and sample areas within them was carried out by LEI and PNXA.

4.3.3 Summary Characteristics

Summary characteristics for each of the individual sample areas, including the number of customers, area, total circuit kilometres, and customer density are provided in Figure 10. The smallest sample area contained 20 customers while the largest contained over 13,000. Customer density, measured as customers per square kilometre, ranges from 0.7 to 667.9. Likewise, customer density, measured as customers per circuit kilometre, ranges for 0.4 to 79.5.

Figure 11 provides a summary of the sample area characteristics, by density class (i.e., low, medium, or high). The average customer density of the low-density sample areas is 6 customers per square kilometre or 3 customers per circuit kilometre. The average customer density of the medium-density sample areas is 43 customers per square kilometre or 16 customers per circuit kilometre. The average for the high-density sample areas is 291 customers per square kilometre or 40 customers per circuit kilometre.

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Figure 10: Summary Characteristics of Individual Sample Areas

Operating Area	Sample Area	Number of Customers	km^2	Circuit km	Customers per km^2	Customers per Circuit km
Bracebridge	LD1	154	18.2	25.7	8.5	6.0
Bracebridge	LD2	102	21.4	27.9	4.8	3.6
Bracebridge	LD3	111	19.2	31.9	5.8	3.5
Bracebridge	MD1	1,125	21.7	94.5	51.9	11.9
Bracebridge	MD2	1,417	22.5	74.7	62.9	19.0
Bracebridge	MD3	727	28.8	77.2	25.2	9.4
Dryden	LD1	103	22.4	43.4	4.6	2.4
Dryden	LD2	20	29.4	47.9	0.7	0.4
Dryden	MD1	872	16.9	43.5	51.6	20.1
Dryden	MD2	1,057	17.4	65.0	60.7	16.3
Dryden	HD1	3,608	22.7	106.1	158.8	34.0
Essex	LD1	179	22.8	38.0	7.8	4.7
Essex	LD2	174	15.0	73.9	11.6	2.4
Essex	MD1	886	21.0	49.4	42.2	17.9
Essex	MD2	912	17.9	44.7	50.9	20.4
Essex	HD1	2,279	20.9	95.1	109.2	24.0
Essex	HD2	1,973	20.5	111.7	96.1	17.7
Kingston	LD1	84	19.3	36.9	4.4	2.3
Kingston	LD2	84	18.8	34.8	4.5	2.4
Kingston	MD1	662	22.8	52.2	29.1	12.7
Kingston	MD2	858	24.0	63.1	35.7	13.6
Kingston	HD1	11,260	16.9	237.3	667.9	47.5
Newmarket	LD1	259	17.4	56.6	14.9	4.6
Newmarket	LD2	271	19.4	33.8	14.0	8.0
Newmarket	LD3	164	18.5	21.7	8.9	7.6
Newmarket	MD1	911	16.7	68.7	54.4	13.3
Newmarket	HD1	3,593	16.5	91.2	218.1	39.4
Newmarket	HD2	8,956	18.0	170.6	498.7	52.5
Newmarket	HD3	8,463	17.2	168.2	492.7	50.3
Newmarket	HD4	3,876	21.3	145.7	181.9	26.6
Owen Sound	LD1	78	19.7	22.1	4.0	3.5
Owen Sound	LD2	63	17.4	30.7	3.6	2.1
Owen Sound	MD1	598	22.0	76.7	27.2	7.8
Owen Sound	MD2	514	19.5	75.2	26.3	6.8
Owen Sound	HD1	10,062	22.4	237.9	448.7	42.3
Perth	LD1	92	20.7	37.6	4.4	2.4
Perth	LD2	130	20.6	33.2	6.3	3.9
Perth	MD1	810	24.3	69.5	33.3	11.7
Perth	MD2	547	24.8	80.1	22.0	6.8
Perth	HD1	3,811	17.5	132.4	217.5	28.8
Perth	HD2	5,366	20.5	193.9	261.2	27.7
Peterborough	LD1	126	24.4	64.8	5.2	1.9
Peterborough	LD2	162	24.7	54.7	6.6	3.0
Peterborough	MD1	949	20.1	58.9	47.2	16.1
Peterborough	MD2	1,182	20.9	71.6	56.5	16.5
Peterborough	MD3	1,237	23.2	63.5	53.4	19.5
Simcoe	LD1	153	20.9	25.2	7.3	6.1
Simcoe	LD2	128	20.5	40.3	6.2	3.2
Simcoe	MD1	938	24.4	54.8	38.5	17.1
Simcoe	MD2	936	13.2	17.5	70.9	53.6
Simcoe	MD3	446	20.0	34.9	22.3	12.8
Sudbury	LD1	137	18.2	32.2	7.5	4.3
Sudbury	LD2	90	19.5	30.9	4.6	2.9
Sudbury	MD1	938	22.2	57.0	42.2	16.4
Sudbury	MD2	808	20.5	52.0	39.4	15.5
Sudbury	HD1	4,674	21.5	106.4	217.7	43.9
Sudbury	HD2	3,361	20.3	100.2	165.7	33.5
Sudbury	HD3	2,032	24.2	51.4	83.9	39.5
Timmins	LD1	123	20.9	25.8	5.9	4.8
Timmins	LD2	39	24.2	26.8	1.6	1.5
Timmins	HD1	13,057	19.7	164.2	663.5	79.5
Timmins	HD2	2,983	17.4	55.1	171.1	54.1

Source: HONI; LEI and PNXA analysis

By design, the average customer-per-square-kilometre densities of the sample area groupings are distinct and there is no overlap at the individual sample area level. For example, within the

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medium-density sample area group the lowest density is approximately 22 customers per square kilometre, whereas within the low-density sample area group the highest density is approximately 15 customers per square kilometre. Likewise within the high-density sample area group the lowest density is approximately 83 customers per square kilometre compared to 71 customers per square kilometre, which is the highest density within the medium-density sample area group.

Figure 11: Summary Characteristics of All Sample Areas

	Number of Customers		Area (Square Kilometres)		Circuit Kilometres	
	Average	St. Dev	Average	St. Dev	Average	St. Dev
Low Density	126	59	21	3	37	14
Medium Density	879	240	21	3	61	17
High Density	5,585	3,567	20	2	135	57

	Customers per Square Kilometre		Customers per Circuit Kilometre	
	Average	St. Dev	Average	St. Dev
Low Density	6	4	3	2
Medium Density	43	14	16	9
High Density	291	197	40	15

Source: HONI; LEI and PNXA analysis

The average customer per-circuit-kilometre densities of the sample area groupings are also distinct. However, there is some overlap at the individual sample area level. Out of 61 sample areas, three overlap.[24] Two low-density sample areas have a density of more than 6.8 customers per circuit kilometre, which is the lowest density of the medium-density sample areas. Only one high-density sample area has a density of less than 20.4 customers per square kilometre, which is the highest density of the medium-density sample areas.

Figure 12: Summary Characteristics of 11 Operating Areas in Study

Operating Area	Number of Customers	km^2	Circuit km	Customers per km^2	Customers per Circuit km	% Wooded Area	% Water Area
Bracebridge	19,382	3,014	2,481	6.4	7.8	76%	16%
Dryden	12,245	101,121	1,758	0.1	7.0	65%	17%
Essex	34,293	1,939	2,663	17.7	12.9	6%	3%
Kingston	48,240	3,019	3,578	16.0	13.5	42%	13%
Newmarket	49,876	1,486	3,098	33.6	16.1	30%	1%
Owen Sound	46,770	4,749	4,801	9.8	9.7	44%	5%
Perth	38,821	4,368	4,207	8.9	9.2	54%	9%
Peterborough	38,359	4,024	5,046	9.5	7.6	36%	9%
Simcoe	15,517	3,596	2,003	4.3	7.7	19%	4%
Sudbury	33,969	7,034	2,724	4.8	12.5	72%	11%
Timmins	22,517	20,004	1,646	1.1	13.7	94%	5%

Source: HONI; LEI and PNXA analysis

24 This excludes one outlying medium density sample area in the Simcoe operating area, which has a disproportionately small amount of distribution circuitry relative to the other medium density sample areas.

This differentiation between the sample areas groups (i.e. the lack of high-, medium-, and low-density sample areas with overlapping customer densities) contributes to the robustness of the study by limiting boundary concerns.

Figure 12 provides the same data as Figure 11, but for each of the 11 operating areas as a whole. As evident, the selected operating areas reflect a broad range of defining characteristics, including size, total circuit length, density, wood cover, and water cover.

4.4 Calculating Assignment Factors

A total of seven distinct assignment factors were developed. A brief description of each assignment factor is provided below and the detailed method for determining the assignment factors is provided in Appendix C. In addition to the individual assignment factors, LEI and PNXA used combined factors. The combined factors were calculated by multiplying individual assignment factors.

Customer Ratio across Entire HONI Service Territory ("CRT")

This assignment factor represents the proportion of the total number of HONI customers across the entire service territory contained within an individual sample area. It is used to assign certain provincial-level OM&A costs.

Customer Ratio within each Operating Area ("CROA")

This assignment factor represents the proportion of the total number of HONI customers in a given operating area contained within an individual sample area. It is used to assign certain operating area OM&A costs.

Customer Distance Ratio ("CDR")

This ratio represents the total distance to the customers in a sample area relative to the total distance to all customers in the operating area. The purpose of this ratio was to assign operating area level OM&A costs to customers in each sample area, recognizing that work crews typically have to travel some distance to customer locations to carry out specific tasks. The ratio is based on "straight-line" distances between customers and the closest service centre, which is an approximation of the actual time it takes for a work crew to reach a given customer.

Underground Conductor Ratio ("UGR")

The purpose of this ratio was to assign operating area level OM&A costs related to underground cables. It represents the proportion of the kilometres of underground cable in a sample area relative to the total operating area.

Pole Distance Ratio (all poles) ("PDRT")

This ratio represents the total distance to the poles in a sample area relative to the total distance to all poles in the operating area. The purpose of this ratio was to assign asset related operating area level OM&A costs to each sample area, recognizing that crews typically have to travel some distance to get to an asset to carry out specific tasks. Examples of this would include repairing or replacing poles or conductor after storm damage. Similar to the customer distance ratio, this assignment factor is based on the straight-line distance between an asset and the service center as an approximation for the time it takes a work crew to reach an asset.

LEI and PNXA performed a sensitivity analysis to determine whether straight-line distance was a reasonable approximation for estimated driving time. The results of this analysis are provided in Section 4.9.

Interruption Ratio Non- Storms ("IRNS")

The purpose of this ratio was to assign operating area level trouble call related work program costs that are non-storm related. It represents the proportion of non-storm related trouble calls (interruptions and non-interruptions) in an operating area that relate to an individual sample area.

Interruption Ratio Storms ("IRS")

The purpose of this ratio was to assign operating area level trouble call related work program costs that are storm related. It reflects the proportion of storm related trouble calls (interruptions and non-interruptions) in an operating area that relate to an individual sample area.

Detailed calculation methodologies as well as the specific sample area assignment factors are provided in Appendix C. It should be noted that 2010 data (customer counts, asset counts, replacement costs) was used to develop the assignment factors, with the exception of interruption ratios, which were calculated for each specific year based on the interruption/non-interruption data for that year.

4.5 Direct Assignment of OM&A Costs

OM&A costs were directly assigned to individual sample areas on the basis of the assignment factors discussed above. The direct cost assignment analysis focused primarily on OM&A expenses related to sustainment activities. Sustainment activities include distribution line maintenance, distribution station maintenance, and vegetation management. Sustainment activities represented approximately 57 percent of HONI's estimated 2010 OM&A expenditure.[25]

The OM&A costs that were included in the direct cost assignment analysis provide a reasonable basis for assessing whether there is a relationship between distribution service costs and customer density. The balance of the OM&A costs are customer care, shared services, operations, and development related, and as such are generally not expected to vary on a per-customer basis with density. However, as described in Section 5, it is necessary to take these

25 HONI. "Cost of Service Summary: Exhibit C1, Tab 1, Schedule 1 (EB-2009-0096)". September 2009.

costs into consideration when analyzing the existing rate classes and the appropriateness of the existing density weighting factors.

OM&A costs are generally tracked at one of three levels: provincial (e.g., engineering services, etc.); operating area (e.g., line patrols and asset maintenance, etc.); or by feeder (i.e., vegetation management). Certain assignment factors could be directly applied to provincial-level costs, for example customer distance ratio. Other assignment factors are only relevant to operating area level costs. Figure 13 summarizes the specific assignment factors that were used to assign the range of OM&A costs considered.

Figure 13: Mapping of OM&A Cost Categories and Assignment Factors

OM&A Cost Category	Assignment Factor
Cable Locates	UGR
Corrective Maintenance	PDRT
Customer Disconnects and Reconnects	CDR
Distribution Lines Patrol	PDRT
Field Meter Reading and Ancillary Services, inc. Meter Replacement	CDR
Field Collections and Special Investigations	CDR
Sentinel Light Maintenance	CDR
Small External Demand Requests	CDR
Wood Pole Testing	PDRT
Trouble Calls	IRNS*PDRT
Storm Maintenance Costs	IRS*PDRT
Distribution Station Operation and Maintenance Costs	CROA
Provincial Level Operation and Maintenance Costs	CRT

Source: LEI and PNXA analysis

LEI and PNXA collected OM&A cost data for a total of five years (2006 through 2010). Originally available in nominal dollar values, the annual data was adjusted to 2010 dollar values using the Canadian consumer price index. As will be discussed in more detail in the context of the results, this allowed for averaging across years.

Vegetation management costs were assigned to the sample areas in a slightly different manner. Vegetation processes in HONI address tree clearing and brush control on a planned and proactive basis. Historic cost data for tree clearing and brush control covering a 10-year period were provided by HONI for the feeders that serve customers in the sample areas that were selected. The annual cost data was put on a common 2010 dollar basis using the Canadian consumer price index. Brush control and tree clearing costs were totalled and divided by 10, the historical average duration of a clearing cycle, to provide a levelized annual vegetation control cost for each feeder.[26]

The total length of the feeders and the length of the feeders within each sample area were obtained from the GIS. The total vegetation control costs for each sample area were then

26 Vegetation control cycles vary across the province. HONI recommended the use of 10 years as it reflects the historical average for the entire service territory.

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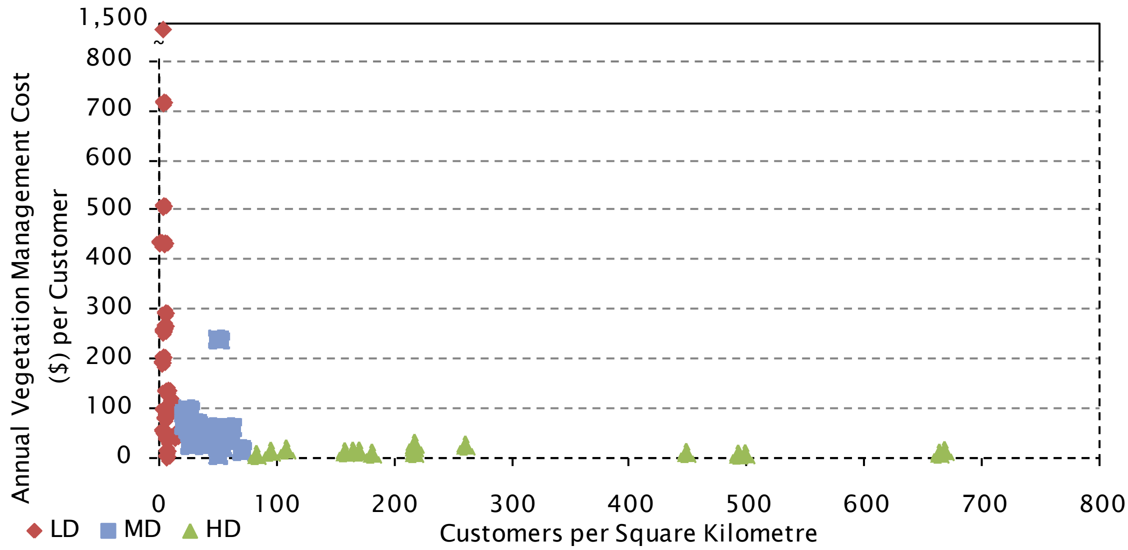
calculated as a proportion of the total feeder cost equivalent to the proportion of the total length of feeder within the sample area.[27] Vegetation management costs (on a per-customer basis) for each of the sample areas are plotted against the density of the sample area in Figure 14.

Figure 14: Annualized per-customer Vegetation Costs for All Sample Areas



Source: HONI; LEI and PNXA analysis

4.6 Asset Intensity

The asset intensity analysis estimates the replacement cost of existing HONI distribution assets attributable to the individual sample areas. Assets located within the sample areas were identified using the GIS. Based on current replacement costs, the total value of assets used to serve a sample area was calculated. The total replacement cost value was then divided by the total number of customers in the sample to obtain the per-customer replacement cost (the "asset intensity").

The choice of replacement cost as opposed to another proxy for capital cost such as net book value is not expected to have a material impact on the results. LEI and PNXA do not have reason to believe that the assets serving low-density sample areas are consistently older or newer than the assets serving medium- or high-density sample areas. Statistical analysis of operating area level data compiled for the econometric analysis suggests that there is only a weak correlation (< 0.3) between age and customer density.

Note that the asset intensity analysis is based on the number of assets physically located within the sample areas. This assumption tends to lead to lower asset intensity results for sample areas that are remote from distribution stations, as typically there would be a long radial feeder and other assets outside of such sample areas that are used to serve customers in these areas. Conversely, high-density areas are typically located in proximity to a distribution station and all

[27] M Class feeders passing through the sample areas were also included in this calculation.

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the equipment serving customers in the high-density area is more likely to be physically located within the high-density sample area.

The replacement costs of assets used in this study are summarized in Figure 15. The costs reflect the average cost to replace typical assets in use by HONI across a wide range of conditions.

Figure 15: Replacement Cost used to Calculate Asset Intensity

	Asset Replacement Cost
High Voltage Distribution Station	$3,500,000
Low Voltage Distribution Station	$2,500,000
Transformer	$4,700
Pole	$7,350
Overhead Conductor (per km)	$1,000
Underground Cable (per km)	$10,000
Submarine Cable (per km)	$56,000
Regulator	$7,750
Recloser	$7,750
Capacitor	$8,600
Fuse	$100
Switch	$30,000
Smart Meter	$100
Smart Meter Repeater	$250
Smart Meter Collector	$1,800

Source: HONI; LEI and PNXA analysis

Costs associated with both the high- and low-voltage distribution stations were assigned to all customers served by the distribution station. The proportion of the distribution station replacement cost attributable to an individual sample area was calculated based on the proportion of the total number customers supplied from the distribution station that are physically located within the sample area.

4.7 Results

The annual results for the individual sample areas for 2006 through 2010 were averaged to minimize the impact of the cyclical nature of some work programs on the study results.

The low-density sample area assigned OM&A costs range from $89 to $1,868 per customer, with a mean value of $379. The medium-density sample area assigned OM&A costs range from $83 to $342 per customer, with mean value of $156. The high-density sample area assigned OM&A costs range from $56 to $157 per customer, with mean value of $89.

The low-density sample area asset intensities range from $7,083 to $61,279 per customer, with a mean value of $27,925. The medium-density sample area asset intensities range from $4,848 to $18,338 per customer, with mean value of $10,792. The high-density sample area OM&A costs range from $2,265 to $9,037 per customer, with mean value of $5,244. Individual sample area results are provided in Figure 57, Figure 58, and Figure 59 in Appendix C.

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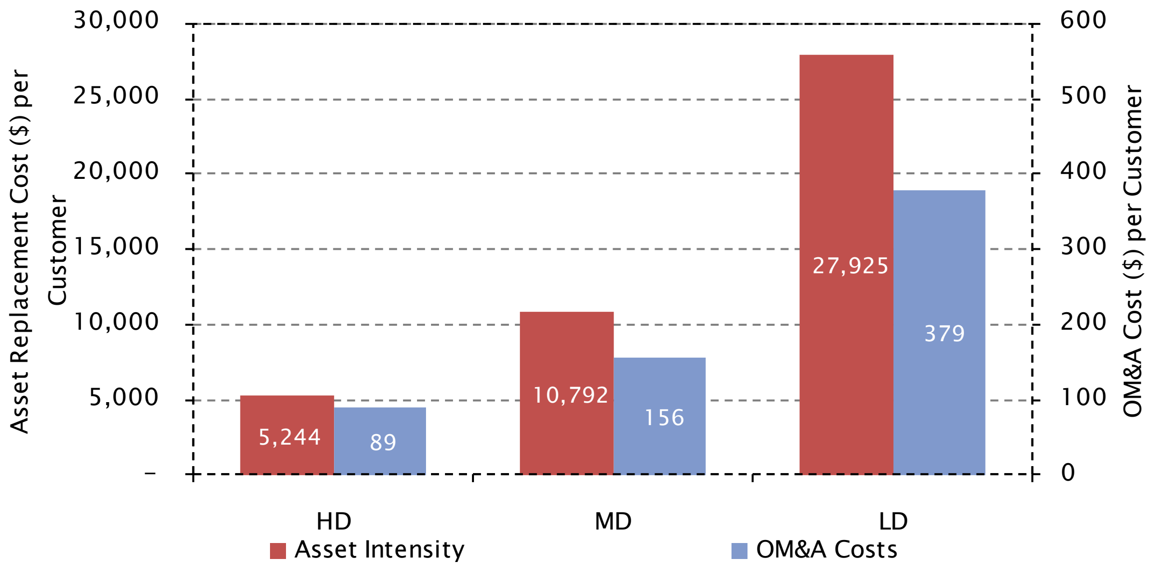
As can be seen in Figure 16, each sample area group appears to have a distinct mean value for both OM&A and asset intensity. The mean value of the high-density sample areas appears to be lower than the mean value for the medium-density sample areas, which in turn is lower than the mean value for the low-density sample areas.

Figure 16: Comparison of Sample Area Mean Costs

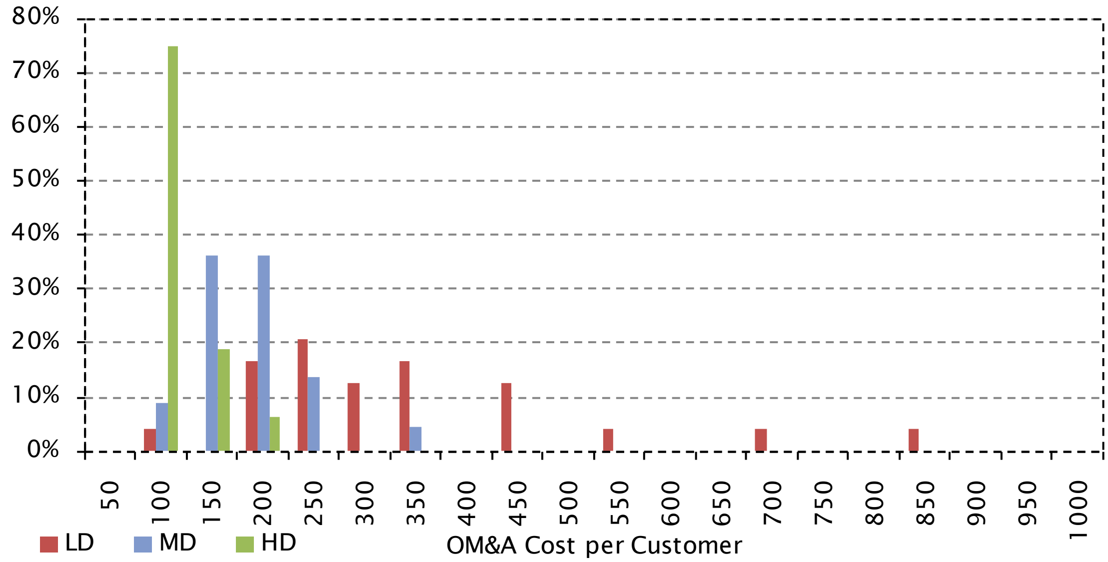


Source: LEI and PNXA analysis

As discussed above, there are a range of costs associated with the high-, medium-, and low-density sample areas. Plots of the distribution (histograms) of the low-, medium-, and high-density sample area results, for both OM&A costs (Figure 17) and asset intensity (Figure 18), reveal that there is some overlap.

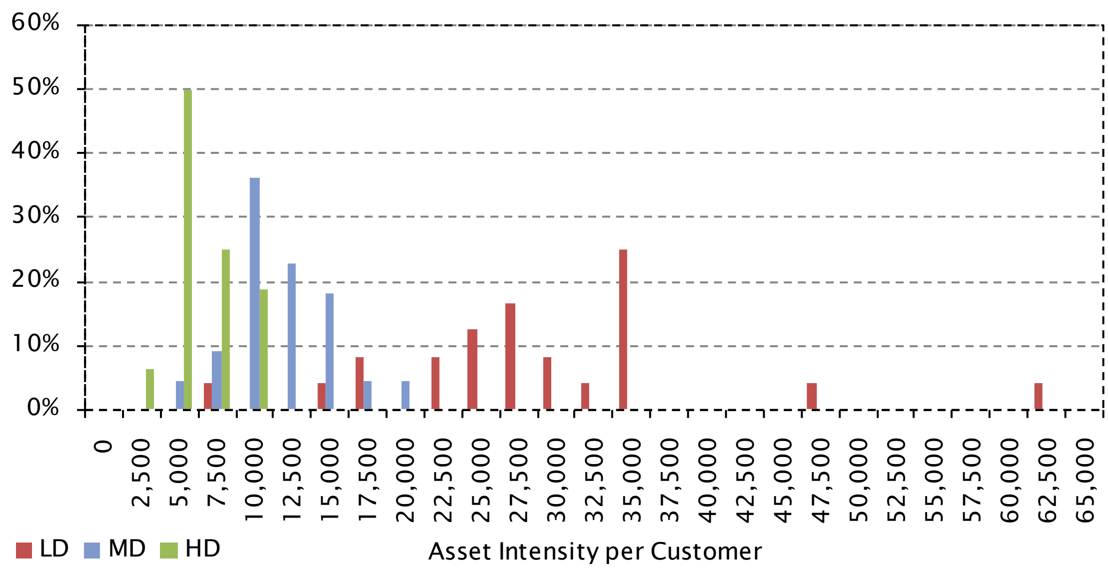
With this overlap present, further analysis was required to determine if the mean values of the distributions are in fact different, from a statistical standpoint. That is, could it be reasonably concluded that the high-density sample area mean value is different and less than the medium-density sample area mean value, and similarly when comparing the high- and low-density and medium- and low-density sample area mean values.

Figure 17: Distribution of per-customer Assigned Sample Area OM&A Costs



Source: LEI and PNXA analysis

Figure 18: Distribution of Asset Intensity Results



Source: LEI and PNXA analysis

The t-test was used to determine if the distributions of the low-, medium-, and high-density sample area results could have come from the same underlying population or not, and with what confidence a conclusion could be stated. The calculation was carried out with the hypothesis that the two sample area result distributions were drawn from the same underlying population.

When the t-test was applied to the low-density and medium-density OM&A results, at the 99 percent confidence level the t-statistic was 3.014. This implies that the probability of the

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hypothesis being true was 0.0060 on a two tail or absolute value basis, and 0.0030 on a one tail basis. Hence, when comparing these two distributions it can be concluded, with 99 percent confidence, that the two distributions are drawn from two underlying populations that are different and that have different mean values.

Similar results were obtained when comparing the medium-density and high-density OM&A results and for all the asset intensity results. Therefore although these three distributions appear to overlap, as illustrated in the figures above, the t-test reveals that all three of the distributions are drawn from different underlying populations.

Figure 19: Summary of Statistical Analysis

	OM&A			Asset Intensity		
	t-Stat	1 Tail	2 Tail	t-Stat	1 Tail	2 Tail
Low versus Medium	3.0140	0.0030	0.0060	7.3518	0.0000	0.0000
Medium versus High	5.1275	0.0000	0.0000	6.6359	0.0000	0.0000

Note: Results rounded to 4 decimal places
Source: LEI and PNXA analysis

Hence, the results of the direct cost assignment analysis demonstrate that there is a statistically significant inverse relationship between customer density and the cost to serve distribution system customers.

4.8 Impact of Very Low Customer Density

In the direct cost assignment analysis, the low-density sample areas were chosen with varying distances from a service centre and typically 100 to 200 customers, although some sample areas with as few as 20 customers were also considered. However, in some of the larger operating areas there are sparsely populated areas that are both a substantial distance away from a service centre and have far fewer customers. Based on the selection criteria presented above in Section 4.3, such remote and sparsely populated areas were avoided. However, to get a sense of the costs associated with serving HONI's more remote customers, a very low-density sample area was analyzed. The sample area, located in the Dryden operating area, was not included in the results of the direct cost analysis because of the extremely low customer density.

The sample area contains a total of three customers and has an area of 21.4 square kilometres, which is close to the notional 20 square kilometres used for the rest of the sample areas in this study. The costs per customer for this sample area have been calculated using the same methodology as for the rest of sample areas, and are presented below in Figure 20.

Figure 20: Per-customer Results for Very Low Density Sample Area

	OM&A	Asset Intensity
Very Low Density ("VLD") Sample Area	4,574	368,467
Average of all Low Density Sample Areas (excluding VLD)	379	27,925
Maximum of all Low Density Sample Areas (excluding VLD)	1,868	61,279
Ratio VLD to Average of all Low Density Sample Areas	12	13
Ratio of VLD to Max of all Low Density Sample Areas	2	6

Source: LEI and PNXA analysis

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The results clearly show that both the OM&A costs and the asset intensity per customer are significantly higher than the rest of the sample areas analyzed. The asset intensity is approximately six times greater than the maximum of all of the low-density sample areas. The OM&A cost per customer is approximately twice the maximum of all of the low-density sample areas.

These results demonstrate that if wider selection criteria for the low-density samples areas were adopted, the mean and the standard deviation of the low-density sample area results likely would have been higher.

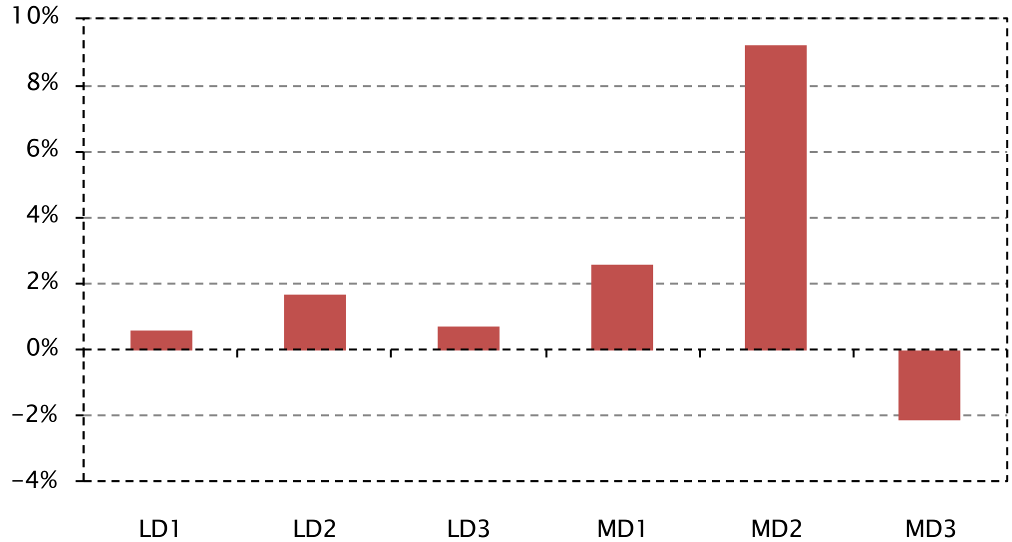
4.9 Driving Time versus Straight-line Distance

One of the assumptions in the direct cost assignment method is that some of HONI's OM&A expenses are proportional to the distance from the customer (or asset) to the closest service centre. Costs relating to trouble calls, pole maintenance, patrol and inspection, etc. were all assigned using distance from the customers to the service center, or distance from the pole to the service center. All of the assignment factors used a "straight-line" or as the "crow flies" distance based on coordinates obtained from the GIS. Depending on the roads, weather, traffic conditions and work location scheduling, the driving time to and from customers or to and from equipment can change significantly.

To test the sensitivity of the results to this approach, LEI and PNXA re-estimated the results for one operating area using assignment factors based on estimates of "drive time" as opposed to straight-line distance. The operating area that was selected for the sensitivity was Bracebridge. With all the lakes in the Bracebridge operating area it was thought that this would represent the extreme in terms of the difference between driving time and straight-line distance.

As illustrated in Figure 21, the use of driving time instead of straight-line distance has a marginal impact on the results of the assignment of OM&A costs. There does not appear to be a uniform or consistent relationship between the impact on the results and the density of the sample areas. Furthermore the results of this sensitivity illustrate that while some assigned sample area costs might increase if straight-line distance was replaced with driving time, others of like density could decrease. Hence, the use of straight-line distance for allocating costs appears to be reasonable.

Figure 21: Percent Change in Directly Assigned per-customer OM&A Costs



Source: LEI and PNXA analysis

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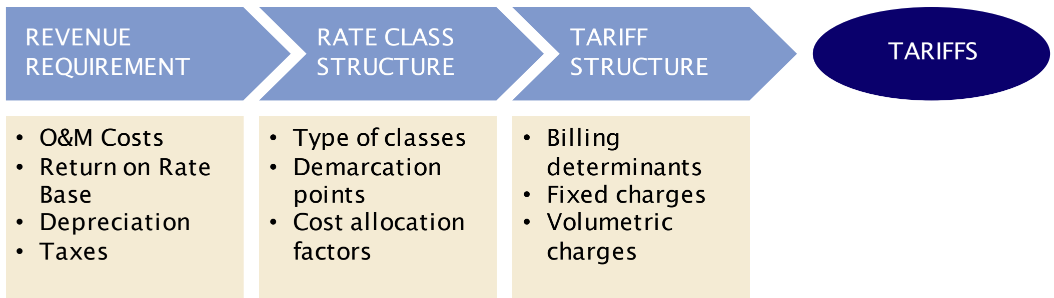
5 HONI's Current Tariff Design

In general, distribution utility tariff (or rate) design consists of three steps:

- calculating the revenue requirement,
- determining rate classes and allocating appropriate costs to them, and
- formulating a structure for the tariffs.

Figure 22: Components of Standard Distribution Tariff Design



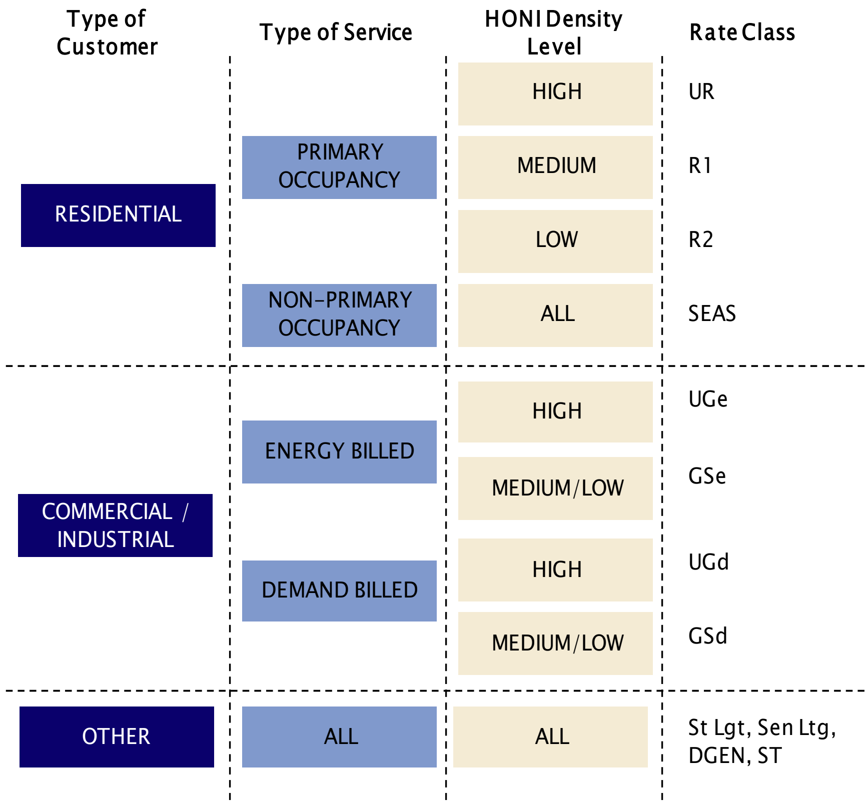
The analysis presented in this report offers insights into the appropriateness and reasonableness of the rate class structure component of HONI's existing tariff design. The analysis undertaken was not intended to nor does it allow for any direct inference to be drawn as to the appropriateness and reasonableness of the revenue requirement or tariff structure components.

There are three elements to HONI's existing rate class structure to consider:

- the number and type of rate classes that are utilized;
- the demarcation points between the various rate classes; and
- the cost allocation factors that assign costs to the different classes.

HONI has a total of 12 rate classes. A three-step segmentation process is used to classify distribution customers. The first level of segmentation is based on the category of customer: residential, commercial/industrial (i.e., general service), or other. The second level of segmentation is based on the functionality of service: energy billed or demand billed for general service customers; and primary or non-primary occupancy for residential customers. Finally, the third level of segmentation involves classification based on customer density. HONI defined three levels of density for year-round residential customers and two levels of density for general service customers. All seasonal customers are placed within the same rate class with its own average density.

Figure 23: Structure of HONI's Current Distribution Rate Classes



Demarcation points are established to facilitate the segmentation of customers based on density. Currently, an "urban" zone (consisting of the UR, UGe, or UGd rate classes) is defined to be an area containing more than 3,000 total customers and having a line density of at least 60 customers per circuit kilometre. General Service customers outside of an urban zone are all classified as non-urban and segmented into the GSe or GSd rate classes. For year-round residential customers, there is an intermediate density level (consisting of the R1 rate class) defined to be areas containing more than 100 total customers and having a density of at least 15 customers per circuit kilometre. Finally, the remaining year-round residential customers are segmented into the lower density R2 rate class.

The OEB's distribution CAM establishes a province-wide approach to allocating costs to the individual rate classes. HONI has modified the CAM to take into account customer density segmentation. This modification includes establishing new rate classes as well as incorporating density weighting factors to assign costs to the individual rate classes. Details of the modifications HONI has made to the CAM are available on HONI's website. An extract of the discussion from HONI's 2010/2011 distribution rate application is provided in the text box below.

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Density Weighting Factors - Excerpts from HONI 2010/2011 Rate Application

"Density factors have been incorporated as weighting factors for overhead lines and transformer related costs."

"For lines, customer density weighting factors were developed by calculating for all feeders the number of customers by customer class on each feeder and assigning the total distance of the feeders to the various customer classes proportionally. A similar method was used to develop demand density weighting factors, by using energy by customer class by feeder and total energy supplied by feeder to assign the feeder length for each feeder to customer classes proportionally."

"For transformers, customer density weighting factors were developed by calculating net book value of transformation assets by feeder and assigning the total net book value of transformation assets by feeder to the various customer classes proportionally. A similar method was used to develop demand density weighting factors, by using energy by customer class by feeder and total energy supplied by feeder to assign the net book value of transformation assets for each feeder to customer classes proportionally."

Source: HONI 2010/2011 Distribution Rate Application (EB-2009-0096), Application and Pre-filed Evidence, Exhibit G2, Tab 1, Schedule 1.

To fulfill the second objective of this study, as defined in Section 1.1, this chapter of the report discusses each of the three components of HONI's rate class structure identified above in the context of the analysis and results presented in previous chapters.

5.1 Rate Classes and Demarcations

5.1.1 Density as a Differentiator

Question: Is it reasonable to have rate classes that are differentiated by customer density?

One of the principal objectives when defining rate classes is to ensure "fairness of the specific rates in the apportionment of total costs of service among different ratepayers so as to avoid arbitrariness and capriciousness and to attain equity".[28] Of particular relevance to this study, are the concepts of "horizontal equity" (i.e., equals treated equally) and "vertical equity" (i.e., non-equals treated unequally). The first objective of the study, to evaluate the relationship between customer density and distribution service costs, is in effect asking the question of whether or not customers with dissimilar densities are unequal with respect to the costs incurred by HONI to serve them.

The results of the econometric and direct cost assignment analysis demonstrate that the cost to serve customers of different "densities" is in fact different. As such, in keeping with cost-causation principles it appears reasonable for HONI to use rate classes that are differentiated based on customer density.

[28] Bonbright, James C., Alberta L. Danielson and David R. Kamerschen. The Principles of Public Utility Rates (Second Edition). Public Utilities, Inc.,1988. Print. pp 383-384.

5.1.2 Number of Density-based Rate Classes

Question: How many density-based rate classes (e.g., high, medium, and low vs. high and low, etc.) are reasonable?

HONI currently has three density-differentiated rate classes for year-round residential customers and two density-differentiated rate classes for general service customers. While neither the econometric nor the direct cost assignment analyses are able to directly address this question, the results offer some insights.

As discussed in Section 4.7, the direct cost assignment analysis has shown that there are statistically significant differences between the mean assigned costs for the high-, medium-, and low-density sample areas. Based on this evidence it is reasonable to conclude that three density differentiated rate classes (a low, medium, and high) appears justified.

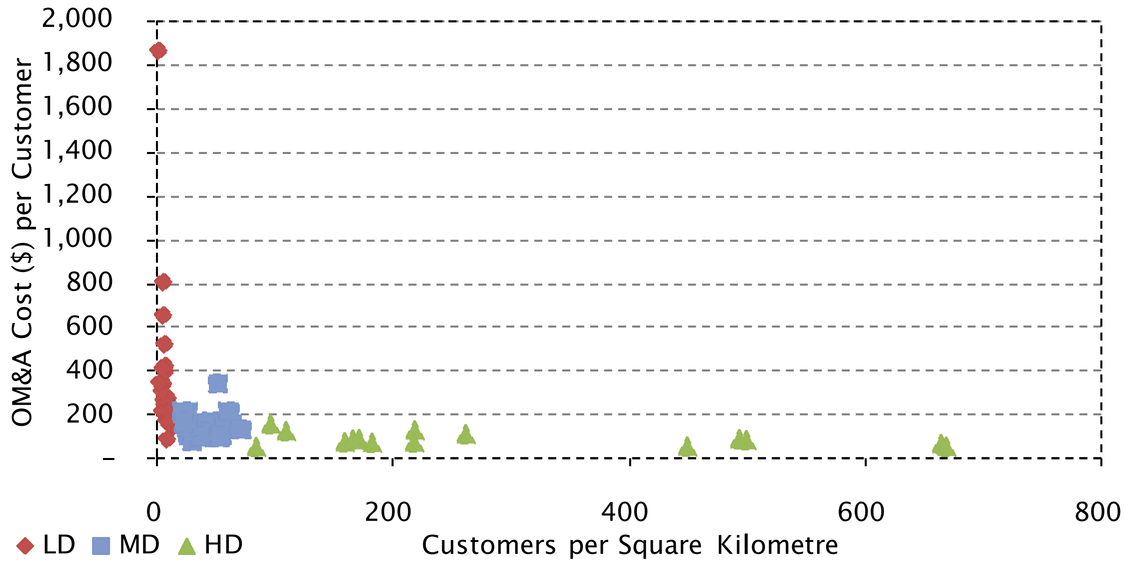
Selecting the appropriate number of rate classes requires a careful balance between minimizing the degree of cross subsidisation and maintaining a reasonable number of customers in each class. Given that HONI has substantially fewer general service customers (~110,000) when compared to the number of residential customers (~1,100,000), limiting the number of density-based general service rate classes to two is reasonable.

Figure 24 below illustrates the relationship between the per-customer assigned OM&A costs and customer density (measured by the number of customers per square kilometre) for the sample areas. Similarly, Figure 25 shows the relationship between the per-customer asset replacement costs and customer density for the sample areas. The two graphics reveal similar patterns, the variability of the estimated sample area assigned cost decreases as density increases. The results yield the same conclusions when considering density based on the number of customers per circuit kilometre, as shown in Figure 60 and Figure 61 in Appendix C.

The variability of the assigned costs within a given density group (high, medium, low) can be taken to represent the degree of cross-subsidisation that potentially exists. Variability in the assigned costs is representative of the range of costs associated with serving individual customers in a group or class. As the range increases, or widens, the average cost to serve may remain constant, however, the low-cost customers provide a larger subsidy to the high-cost customers. Conversely, as the range decrease, or tightens, the subsidy diminishes.

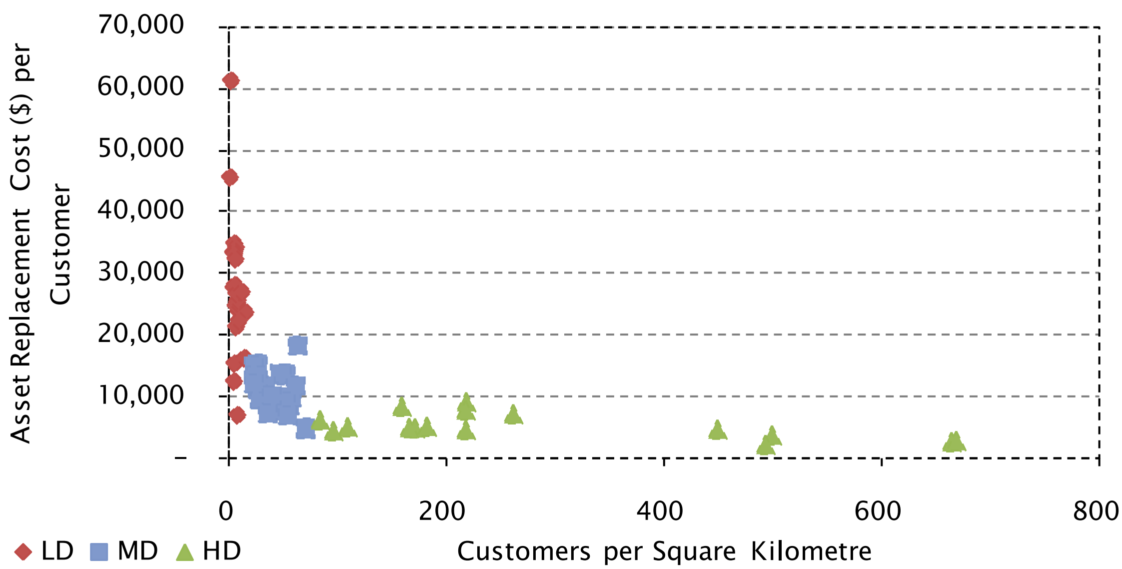
As illustrated by Figure 24 and Figure 25, there is only a small variation in the estimated cost to serve sample areas when customer density is above 100 customers per square kilometre. While there is more variability across the medium-density sample areas than across the high-density sample areas, this level of variability is still rather limited.

Figure 24: Relationship between per-customer Assigned OM&A Costs and Customer Density



Source: LEI and PNXA analysis

Figure 25: Relationship between per-customer Asset Replacement Cost and Customer Density



Source: LEI and PNXA analysis

There is considerably more variability in the assigned costs for the low-density sample areas. This suggests that there may be a greater degree of cross subsidization within low-density rate classes. One possible way to minimize the degree of cross subsidization would be to introduce additional low-density rate classes.

While creating additional rate classes may reduce potential cross subsidies within the low-density rate classes, there are other factors that need to be considered. Cost allocation is a zero-sum game, hence if one rate goes down another must go up to balance the total revenue

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generated. Cost allocation is rarely perfect, and some degree of cross subsidization within a rate class is also to be expected. These factors need to be taken into account when considering measures to reduce potential cross subsidies within HONI's current rate classes.

Overall, however, based on the results of this study, there does not appear to be an immediate or pressing need to change the number of existing density-based rate classes.

5.1.3 Demarcation Points

Question: What should form the cut-off point between the density-based rate classes?

The study was not specifically designed to address this question. As such additional data and analysis would be required to conclusively determine the reasonableness of HONI's existing demarcation points or determine alternatives. It should be noted however, that the study did not provide strong evidence to support changing the existing demarcation points. While minor adjustments could be made, there are costs and benefits associated with such a transition.

HONI's current demarcation rules allow for interpretation, in particular when determining the specific geographic boundary between two rates classes. This has led to some discussion around the use of municipal or other political boundaries, which are "better" defined and understood by customers. The issue of alternate rate classes and demarcations is discussed in additional detail in Section 6.

5.2 Cost Allocation Factors

Question: Do HONI's existing density weighting factors accurately reflect the relationship between customer density and cost of service, as reflected in this study?

To judge the reasonableness of the existing density weighting factors, LEI and PNXA compared the overall outcome of HONI's CAM to the results of the direct cost assignment analysis.[29]

Figure 26 summarizes the results of the CAM used by HONI in its 2010/2011 distribution rate application. The costs allocated to the UR class are equivalent to $419 per customer, whereas the costs allocated to the R1 and R2 classes are equivalent to $663 and $1,176 per customer, respectively. The costs allocated to the Seasonal residential class are $612 per customer, slightly lower than the per-customer cost allocated to R1 customers. The per-customer costs allocated to the GSe and GSd rate classes are higher than those assigned to the UGe and UGd rate classes.

[29] The results of the econometric analysis (i.e. the estimated coefficients) can be used to predict the cost to serve groups of customers of different densities. This is done by inputting values for the parameters in the cost function and calculating the predicted cost based on the formula. However, LEI and PNXA concluded that utilizing the results of the econometrics for the purpose of establishing the reasonableness of HONI's existing cost allocation factors was not feasible. In order to utilize the econometric results to answer this question, a discrete average customer density would have to be established for each rate class. In order to do this, the geographic areas associated with each rate class would have to be established and measured. The length of conductor in that geographic area would also have to be calculated. HONI's GIS does not currently contain this information, as the geographic boundaries between the rate classes are not necessarily well defined. This is particularly true for the R1 and R2 year-round residential classes and for the Seasonal rate class.

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Figure 26: Results of HONI Cost Allocation Model

Rate Class	($ million)	($ per customer)	Ratio Relative to Urban Class*
Residential – UR	$59.0	$419	1.0
Residential – R1	$273.4	$663	1.6
Residential – R2	$431.7	$1,176	2.8
Residential – Seasonal	$96.0	$612	1.5
General Service – UGe	$8.7	$817	1.0
General Service – UGd	$12.6	$11,127	1.0
General Service – GSe	$121.5	$1,230	1.5
General Service – GSd	$128.8	$17,491	1.6

* Residential rate classes are compared to UR, General Service rate classes are compared to UGe and UGd respectively
Source: HONI OEB Cost Allocation Model, 2010/2011 Distribution Rate Application

As previously discussed in Section 4.6, the direct cost assignment analysis did not take into account all of the costs that are allocated by HONI's CAM. Also, the direct cost assignment analysis was based on five years of actual historical cost data, whereas the CAM is based on estimates of going forward costs. It is possible, however, to make some adjustments to the results of the direct cost assignment analysis to take these factors into account.

To begin with, the issue of historical versus going-forward costs can be meliorated by focusing on the ratio of per-customer costs as opposed to the absolute value (e.g., the ratio between UR and R2 per-customer allocated costs is 2.8). This is a reasonable approach, provided the structure of the costs incurred by HONI over the past five years are not expected to be drastically different from the structure of the costs it will incur in the future.[30]

Two additional adjustments need to be made in order to compare the results of the direct cost assignment analysis to the results of HONI's CAM.

- The OM&A costs for the high-, medium-, and low-density sample areas need to be adjusted to reflect all of the costs considered in the CAM. The excluded costs, which primarily consist of shared services and customer care, are estimated to be approximately $162 ($2010) per customer, on average between 2006 and 2010.

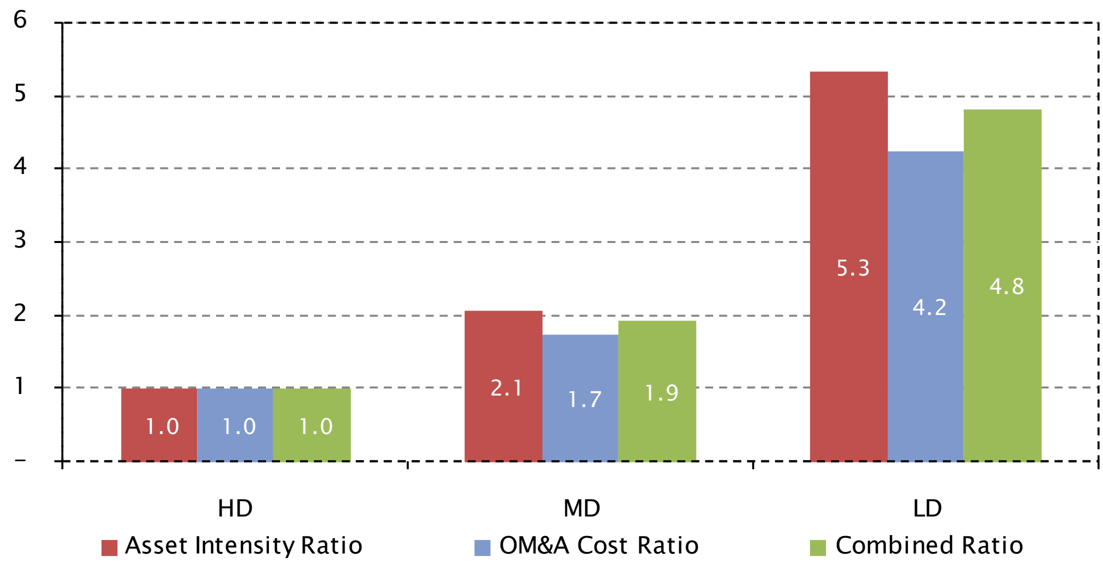
- The asset intensity and OM&A values need to be combined, to reflect the combined allocation of both OM&A and capital costs in the CAM. In HONI's 2010/2011 rate filing, OM&A costs represented 46 percent of the total revenue requirement, while

30 LEI and PNXA do not expect that HONI's cost structure will materially change in the near term. However, it should be noted that technological changes can lead to shifts in the underlying cost structure for a utility. For example, advanced metering infrastructure can reduce the need for in-person meter reading, lowering the OM&A component of a utility's cost structure. On the other hand, the large investments required typically increase the capital cost component of the cost structure. HONI is currently going through this transition. While some shift between OM&A and capital costs may occur as a result, it is not expected to lead to a drastically different cost structure.

capital costs represented 54 percent. This weighting factor is applied to combine the OM&A and asset intensity results from the direct cost assignment analysis.[31]

Figure 27 illustrates the ratios between the mean high-, medium-, and low-density sample area assigned costs before including shared services and customer care OM&A costs.

Figure 27: Unadjusted Ratio of Average Sample Area Costs



Source: LEI and PNXA analysis

Figure 28 illustrates the ratios after including the uniform adjustment for shared services and customer care OM&A costs. The ratio between the low- and high-density sample area combined mean directly assigned asset intensity and OM&A cost is 3.9, whereas the ratio between the medium- and high-density sample area is 1.7.

In the direct cost assignment analysis, the sample areas were selected based on density considerations alone, irrespective of the type of customers that were contained within them. This was done intentionally in order to demonstrate the relationship between customer density and cost of service.

A consequence of this is that the mean density of the sample areas is not necessarily consistent with the mean density of the existing customer rate classes. Based on the sample area selection criteria, the majority of the low-density sample areas have between 100 and 200 customers per 20 square kilometres. Only a small number of low-density sample areas containing fewer than 100 customers were included.

31 Given that asset intensity and OM&A costs per customer are of a different magnitude, ratios between the sample area averages are calculated prior to applying the weighting factors and determining a combined result.

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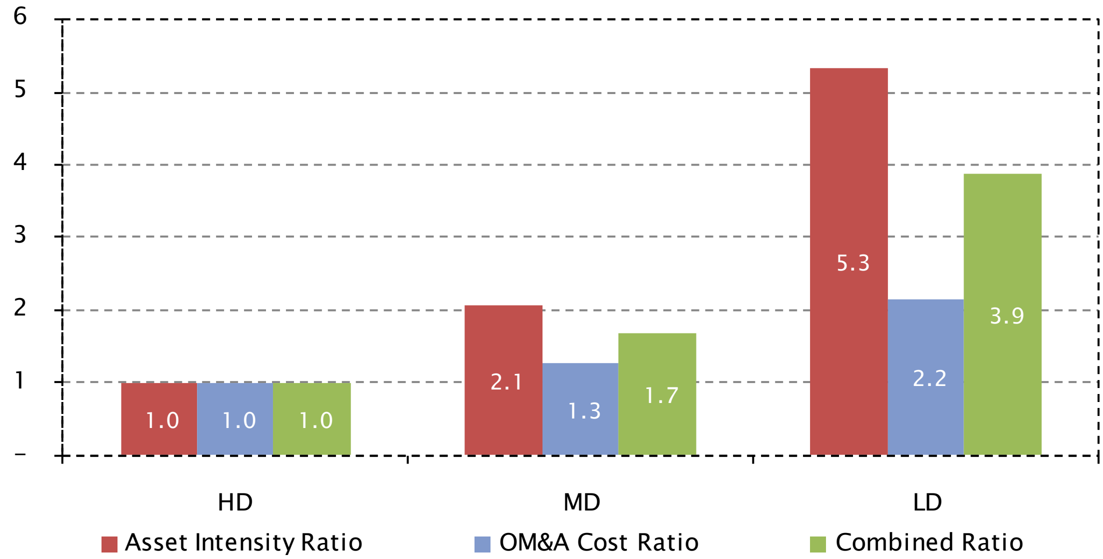
Figure 28: Adjusted Ratio of Average Sample Area Costs



Source: LEI and PNXA analysis

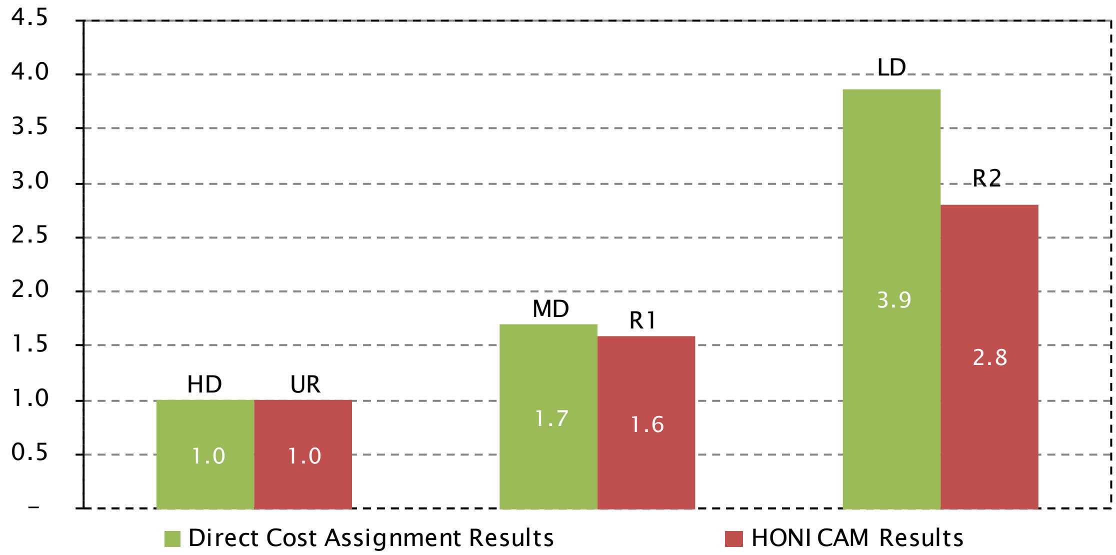
As a result, the proportion of HONI's service territory that has a density of less than 100 customers per 20 square kilometres is likely underrepresented by the low-density sample areas. As a result, the mean density of the low-density sample areas likely overstates the mean density of the service territory associated with R2 customers. Conversely, the mean density of the high-density sample areas likely understates the mean density of the service territory associated with UR customers. This latter assertion is based on the fact that when a number of high-density sample areas were selected, the boundaries had to be extended (i.e. the sample area made larger) in order to maintain a consistent size, which tended to lower the average density of the high-density sample areas.

With the above in mind, the ratio between the per-customer costs allocated to the existing rate classes in the CAM can be compared to the study results. Figure 29 plots the ratios of the sample area combined mean directly assigned asset intensity and OM&A cost, relative to the high-density sample area, and the ratios, relative to the UR class, of per-customer costs allocated to each of the existing year-round residential rate classes (UR, R1 and R2) in the CAM.

Directionally the results are consistent. The ratio between the medium- and high-density sample area mean assigned costs and the R1 and UR allocated costs are similar. The ratio between the R2 and UR allocated costs however, is lower than the ratio between the low- and high-density sample area mean assigned costs.

As mentioned previously, the mean density of the high-density sample areas likely understates the mean density of the UR class and the mean density of the low-density sample areas likely overstates the mean density of the R2 class. As this study has shown, HONI's distribution service costs are inversely related to customer density. Hence, the ratio of the mean assigned costs between the low-, medium-, and high-density sample areas is likely a conservative estimate of the difference in the costs to serve the R2, R1, and UR rate classes.

Figure 29: Comparison of Output from HONI CAM to Adjusted Ratios of Average Sample Area Costs



Source: HONI OEB Cost Allocation Model, 2010/2011 Distribution Rate Application; LEI and PNXA analysis

Based on the above, the results of the direct cost assignment analysis suggest that the existing density weighting factors may not capture the full difference between the mean cost to serve HONI's year-round low-, medium-, and high-density residential rate classes.

With respect to the Seasonal residential class, Figure 63, Figure 64, and Figure 65 in Appendix C suggest that the average customer density of the Seasonal rate class falls between that of the R1 and R2 classes. Hence, from a density perspective, the ratio of the per-customer cost to serve the Seasonal class, relative to the UR class, is expected to fall between the ratios of the per-customer costs to serve the R1 and R2 classes, relative to the UR class.

Similarly, Figure 66 and Figure 67 in Appendix C suggest that the average customer density of the urban general service classes (UGe and UGd) is similar to that of the UR class, whereas the average customer density of the non-urban general service classes (GSe and GSd) falls between that of the R1 and R2 classes. Hence, from a density perspective, the ratio of the per-customer cost to serve the non-urban general service rate classes, relative to the cost to serve and the urban general service classes, is expected to fall between that of the ratios of the per-customer costs to serve the R1 and R2 classes, relative to the UR class.

6 Discussion of Alternate Rate Structures

The final objective of this study was to qualitatively assess a handful of alternative rate structures. The alternative structures considered in this report include: adjustments to HONI's existing rate structure; adopting the use of municipal boundaries; and province-wide or regional postage-stamp rates.

A number of generally accepted criteria have to be weighted when considering distribution rate design or re-design.

- Allocation Efficiency: customers should be charged in proportion to the costs they impose and/or benefits they receive;
- Dynamic Efficiency: incentives for ongoing technological innovation and cost minimization should be consistently maintained;
- Equity: rates should be supportive of fundamental social welfare objectives;
- Administrative Practicality: the process of establishing customer charges should not be unduly burdensome; and
- Stability: predictable patterns over time allow for better planning by both consumers and producers.

Any change in the definition of the existing rate classes or density weighting factors will create winners and losers -- some customers will see their rates increase while others will see their rates decrease. While there may be allocation efficiencies or administrative practicality benefits associated with revising HONI's existing rate structure (e.g., reducing potential cross-subsidies, minimizing the need for "judgement" when defining boundaries, etc.), these need to be considered against the possibility that any change would be disruptive to customers.

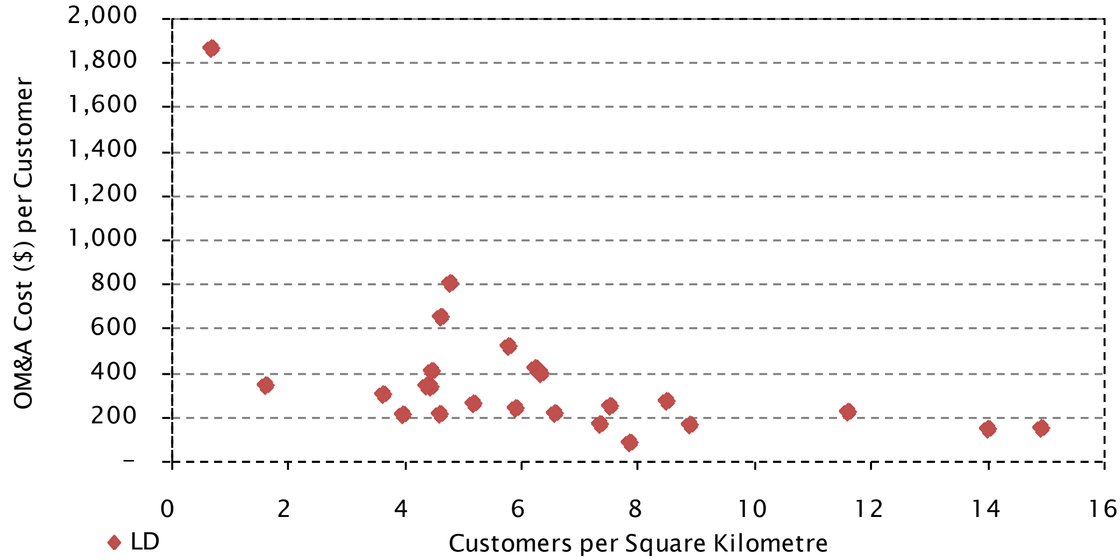
6.1.1 Adjustments to HONI's Existing Structure

As discussed in Section 5.1.2, the results of the direct cost assignment analysis reveal considerable variability in the estimated cost to serve low-density sample areas. While there is not enough evidence available in the current study to draw firm conclusions on this specific issue, additional low-density rate classes may be justified on the basis of fairness in allocating costs and to reduce the apparent levels of cross-subsidization.

It should be noted however, that the variability of costs within the low-density sample areas is not necessarily only the result of varying customer densities. Other factors such as distance from service centre, geography, drive time variations, etc., may lead to differences in the cost of providing service to low-density customers. Figure 30 and Figure 31 show the results of the direct cost assignment analysis (for both OM&A and asset intensity) for the low-density sample areas only. While the relationship between customer density and distribution service costs still appears to be relevant within this density group, it is not as apparent as when considering the full range of densities across HONI's territory. This would suggest that were additional low-density rate classes to be proposed, further analysis would be required to determine the most appropriate demarcations.

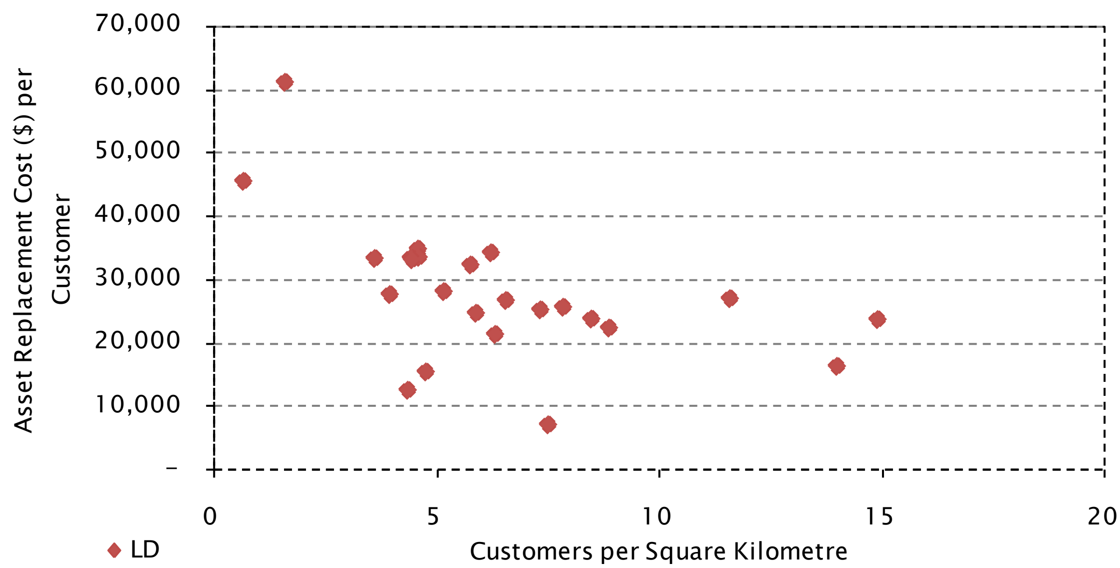
Another possible adjustment to HONI's existing structure could be to refine the demarcation point which establishes the high-density rate classes. The original basis for the 3,000 customer definition appears to be based on the average LDC size at the time the concept of urban-density zones was first created. The results of the direct cost assignment analysis revealed that across a range of high-density sample areas, including those with as few as 2,000 customers, there was limited variability in the directly assigned costs.

Figure 30: Low-Density Sample Area OM&A Costs



Source: LEI and PNXA analysis

Figure 31: Low-Density Sample Area Asset Intensity



Source: LEI and PNXA analysis

Finally, the current demarcation rules, while well defined, require some interpretation with respect to determining the specific geographic boundary between two rates classes. In general, the boundaries for the high-density zones are delineated by extending outwards from a high-density population cluster to a logical boundary such as a main road or river, while ensuring that the criteria for high density are maintained. One possible way to address this issue, which is elaborated upon in the next section, may be to transition towards a municipal (or other "better" defined) boundary.

6.1.2 Municipal Boundaries

Conceptually, the use of municipal (or other political) boundaries to define urban and rural rate classes within HONI is appealing. As stated in the Elenchus Research Associate Report prepared for HONI in July 2009, the use of *"municipal boundaries to define urban service areas has some advantages over [HONI's] density-based approach. In particular, it is probably simpler for customers to understand and therefore would result in a more transparent method from the perspective of customers"*.[32] However, the actual implementation of a design such as this is not necessarily as simple as it may appear at first glance.

To begin with, the majority of all residents in Ontario are located within some form of municipal boundary. The exceptions to this are Ontario residents, primarily in the north, who live within an "unorganized territory", where regional bodies of the provincial government provide services akin to most municipalities.[33] As a result, being located within a municipal boundary is not sufficient to differentiate a customer as "urban". Another metric, for example customer density, population, or population density, would also have to be incorporated into the rate design.

There are also three "tiers" of municipalities in Ontario, lower, single and upper. Depending on the size and history of the municipality, it may be called a city, town, township or village. Municipalities where there is another level of municipal government like a county or region involved in providing services to residents are referred to as "lower tier" (e.g., The City of Thorold within the Niagara Region). Municipalities where there is only one level of municipal government in an area are referred to as "single tier" (e.g., The City of Toronto). Counties or regions are referred to as "upper tier" municipalities as they typically provide services to a federation of local municipalities within their boundaries (e.g., the Niagara or Peel Regions). A municipal boundary based rate design would need to determine the treatment of the different tiers when assigning customers.

Another issue is the number of municipalities in Ontario -- there are a total of 444 today.[34] While LEI and PNXA did not evaluate the number of these municipalities that HONI currently

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32 Elenchus Research Associates. "Principles for Defining and Allocating Costs to Density-Based Sub-Classes". July 2009.

33 Territories without municipal organization (i.e. where there is no local government in place), are commonly referred to as "unorganized territories."

34 Association of Municipalities of Ontario. 19 August 2011. Web. <http://www.amo.on.ca/YLG/ylg/muniont.html>

serves, establishing a separate rate class even for half of them is neither realistic nor prudent. Hence, "like" municipalities will need to be grouped into a common rate class. Whether this grouping is done on a regional, density, or size basis would have to be examined through further analysis. There is likely a trade-off between simplicity, i.e. the number of rate classes, and the allocative efficiency of the rate design, i.e. the apparent level of cross-subsidies.

One approach that could be considered is to make the groupings appear similar to existing HONI rate classes. In other words, the population or density of a municipality can be used to delineate the classes. For instance, if the municipal population (or the number of customer served within the municipality) is greater than 3,000 and the density (again population or customer density) within the municipality is greater than 60 customers per line kilometre, then all customers within the municipality may be classified as UR. If the municipal population is less than 3,000 and the customer density within the municipality is greater than 15 customers per line kilometre but less than 60 customers per line kilometre, then all customers within the municipality may be classified as R1. This approach could also potentially minimize the implications of any changes that would have to be considered in respect of the application of the Rural or Remote Rate Protection ("RRRP") program.

Another issue that arises in the context of municipal boundary considerations is the extent to which the same rate design principles are extended to the other LDCs. While some LDCs only serve customers in a single municipality, many serve multiple municipalities, which can range in terms of size, density, etc. Moving HONI to a rate design which utilizes municipal boundaries, if explored, should be done on a province-wide basis taking into account other LDCs as well.

The Elenchus Research Associate report correctly points out that in "defining customer classes, it is desirable to minimize boundary issues that arise when the criteria for defining classes result in very similar customers falling on different sides of the break point between classes". Incorporating well-defined municipal boundaries into HONI's existing rate class design may help customers to better recognize and understand the delineation between classes, as the boundary would be much more explicit. However, it is still possible that "similar", proximate, customers will fall on different sides and thus be subject to different rates.

6.1.3 Regional Rates

Another alternative design that could be considered is one based on regional postage-stamp distribution rates. Regional distribution rates could be established by pooling the revenue requirements of all the LDCs serving customers in a given region. The combined revenue requirement would then be allocated to customer classes to establish a single series of rates for the region. The combined revenues would then be divided amongst the LDCs based on the proportion of the revenue requirement attributable to an individual LDC (or alternatively, based on electricity consumption within their service territories). Today a precedent exists for this approach in the form of the provincial transmission rates which are based on the revenue

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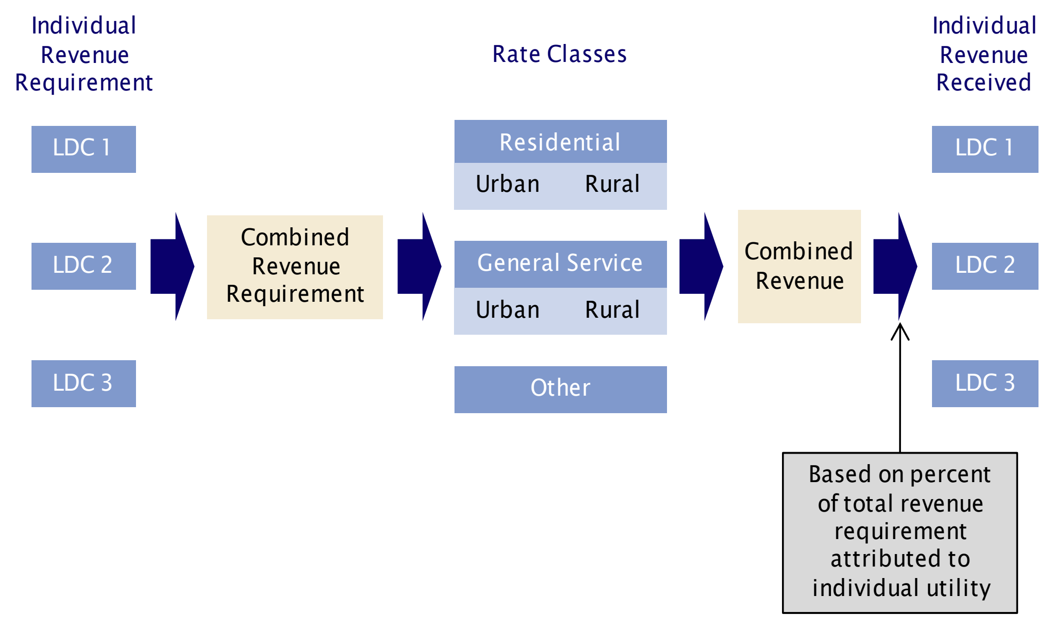
requirement and customer demands served by the four transmission companies.[35] This methodology has been successfully applied since the opening of the electricity market in 2002.

Figure 32: Summary of a Regional Rate Mechanism

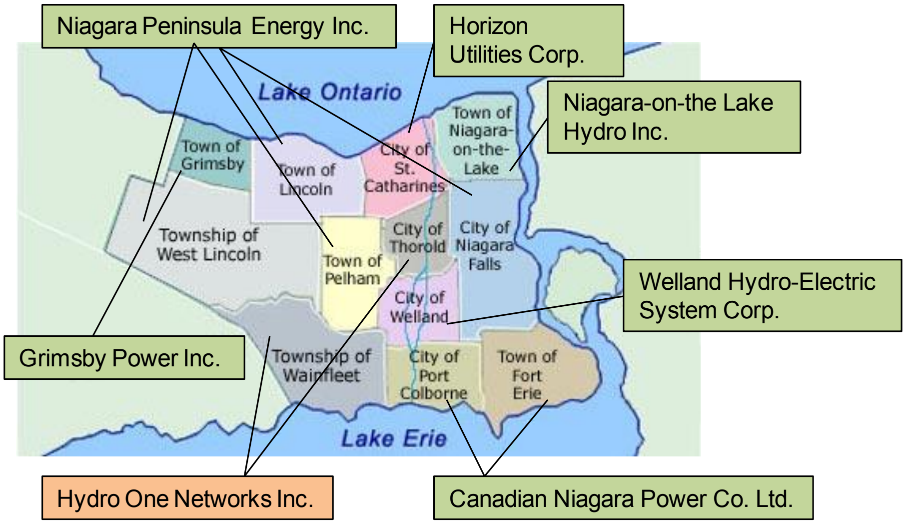


The rate classes could also be established to maintain differences between urban and rural (high- and low-density) customers. Again a precedent exists in the electricity transmission sector where there are separate rates for connection, transformation, and network services.

As an example, there are seven LDCs, including HONI that currently serve customers in the Niagara region. Hence, residential customers in this relatively small geographic region could have one of nine different rates (three possible rates for HONI customers and one each for customers in the other six utility's service territories. Harmonizing the rates would be a simplification for consumers. It may also promote further rationalization in terms of the number of LDCs that exist within the province.

35 OEB. "In the matter of an application by: Hydro One Networks, Inc. 2011 and 2012 Transmission Revenue Requirement and Rates". (EB-2010-0002). Toronto: December 23, 2010.

Figure 33: LDCs in the Niagara Region



Source: IESO

As in most instances of rate re-design, administrative simplicity comes at the cost of allocative efficiency. In the case of a move from LDC-specific to regional distribution rates, customers that were historically in the lower-cost LDCs' service territories could end up subsidizing customers in the higher-cost LDCs' service territories. This may make it more difficult to achieve consensus amongst LDCs with respect to support for a move towards regional distribution tariffs.

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7 Conclusions and Recommendations

As outlined in Section 1.1, the objectives of this study were to (i) evaluate the relationship between customer density and distribution service costs, (ii) assess whether HONI's existing density based rate classes and density weighting factors appropriately reflect this relationship, and (iii) consider, qualitatively, the appropriateness and feasibility of establishing alternate customer class definitions.

Both the econometric analysis and the direct cost assignment analysis establish that there is a statistically significant inverse relationship between customer density and distribution service costs across HONI's service territory. In both studies, distribution service costs were shown to decrease as the customer density of an operating area and/or a sample area increased. The comparison of the output from the HONI CAM with the results of the direct cost assignment analysis suggests that HONI's existing density based rate classes and density weighting factors reflect this relationship, although the density weighting factors may understate the actual difference between the cost to serve high-, medium-, and low-density customers.

Based on the results of this analysis, LEI and PNXA would not recommend wholesale changes to HONI's existing rate class definitions. However, adjustments to the weighting factors used in HONI's CAM could be justified to better capture the differences between the cost to serve high-, medium-, and low-density customers. In doing so, care will need to be taken to ensure that customers do not experience a sense of "rate shock". If the resulting change in rates is significant, a transition period over which the modification is gradually introduced may be required.

Other rate class definitions were also considered (i.e., municipal boundaries or regional rates), however, the move to such a design is a long-term decision that LEI and PNXA recommend be made in the context of a broader provincial dialogue.

Appendix A –Econometric Analysis Details

Introduction to Econometric Analysis

If one hypothesized that distribution service costs were linearly influenced by the number of customers and customer density, Equation 3 below would be the functional form. The parameter (or coefficient) "A" is the intercept term. The presence of a positive value for the "A" intercept means that there is a cost of doing business, regardless of the number of customers. The coefficient "B" represents the incremental cost of one additional customer. The coefficient "C" represents the incremental cost associated with one incremental unit of customer density.

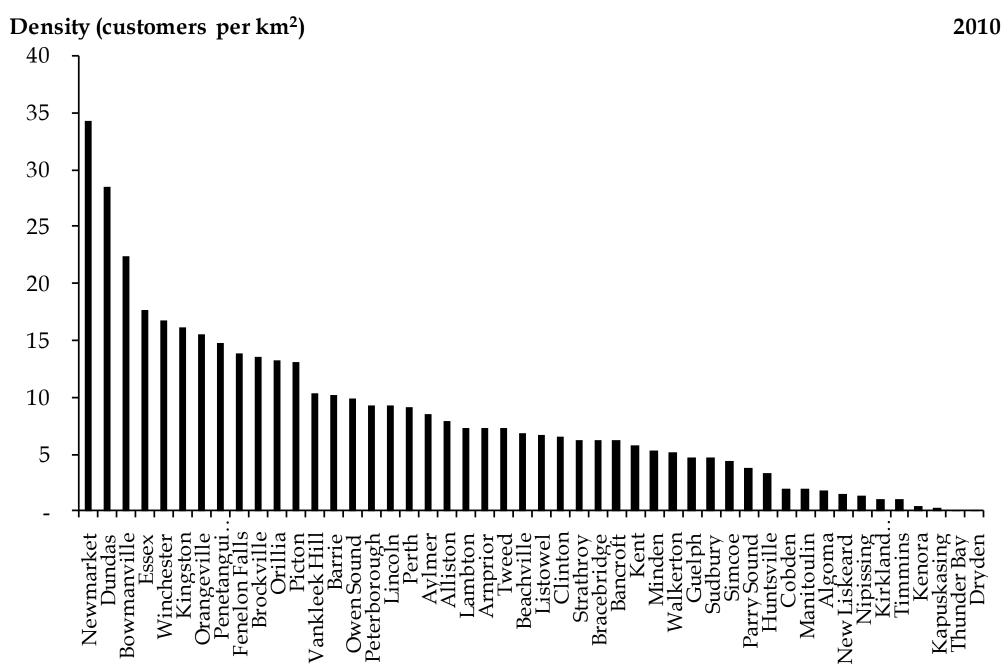
Equation 3

$$Distribution\ Service\ Cost = A + B * Number\ of\ Customers + C * Customer\ Density$$

Equation 3 is a simplification. However, it illustrates one of the advantages of econometric analysis, in the sense that the impact of individual factors (i.e., the number of customers or customer density) on distribution service costs can be simultaneously yet independently analyzed. The coefficients A, B, and C are estimated by collecting real-world data on distribution service costs, the number of customers served, and the customer density, and utilizing one of many possible regression estimation techniques.

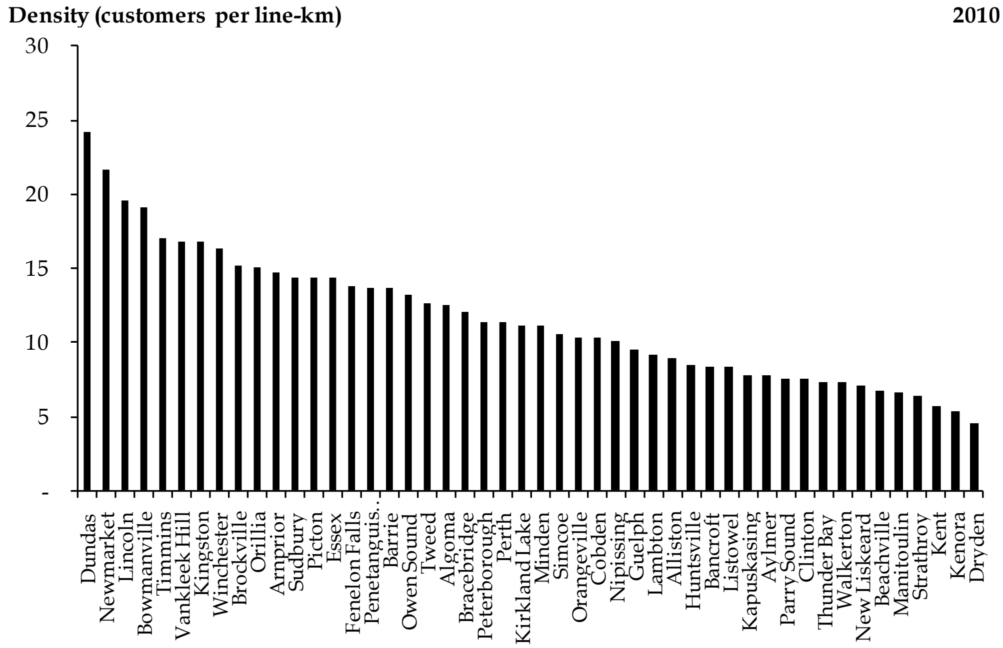
Sample Operating Area Data

Figure 34: Operating Area 2010 Customer Density (per square kilometre)



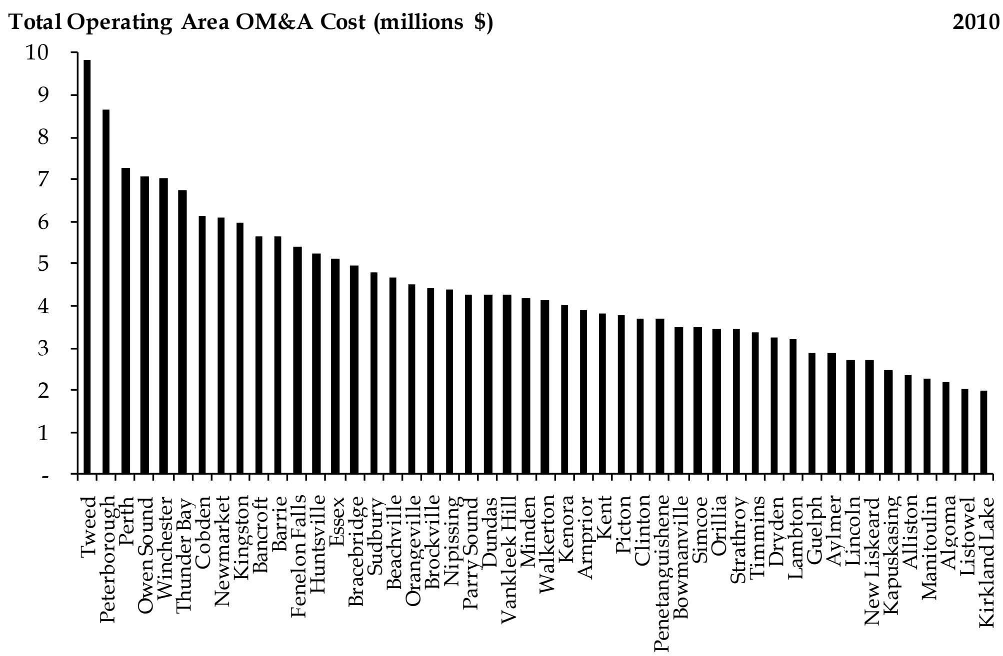
Source: HONI; LEI and PNXA analysis

Figure 35: Operating Area 2010 Customer Density (per circuit kilometre)



Source: HONI; LEI and PNXA analysis

Figure 36: Operating Area 2010 OM&A Cost



Source: HONI; LEI and PNXA analysis

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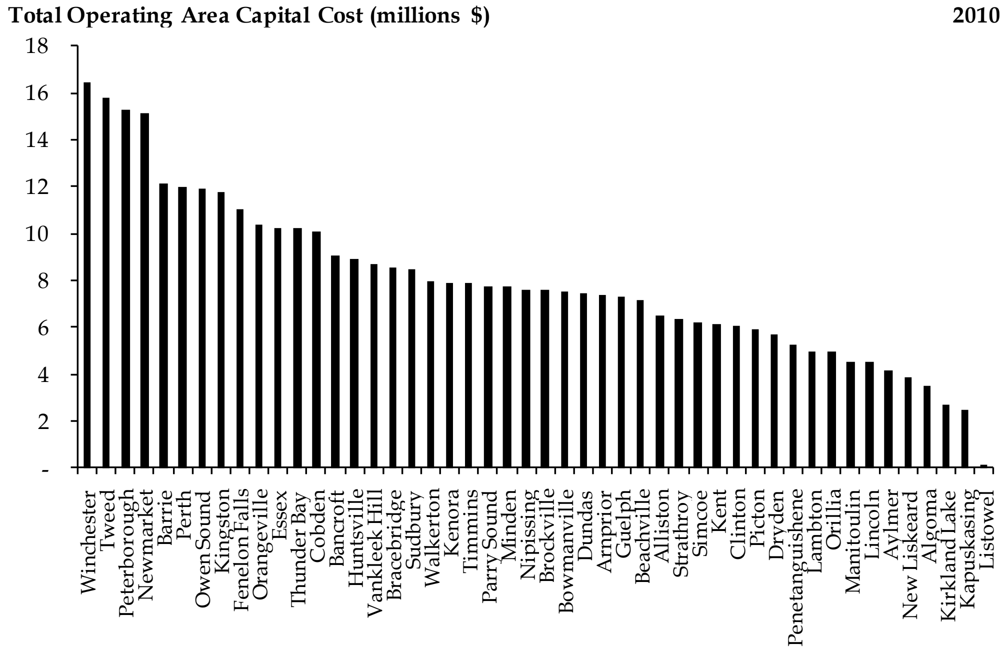
Figure 37: Operating Area 2010 Capital Proxy



Source: HONI; LEI and PNXA analysis

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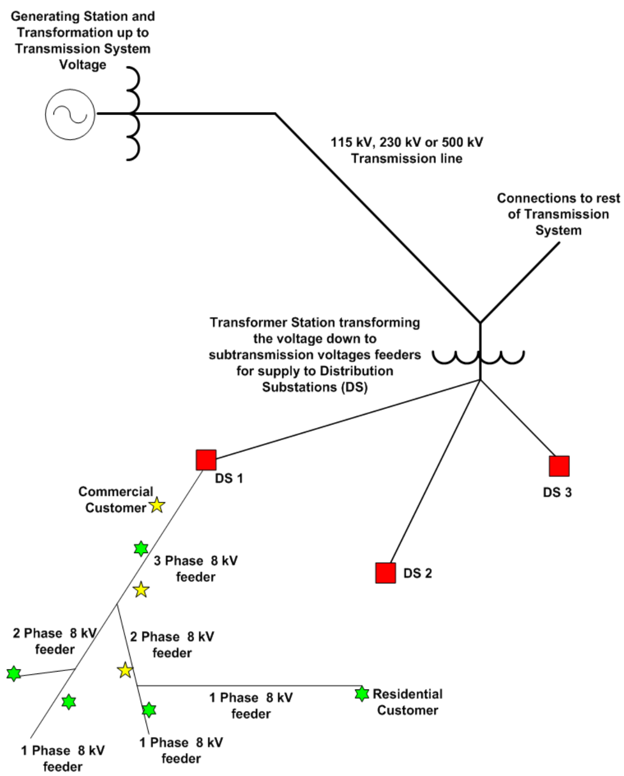
Appendix B – Background Information on Distribution Systems

Distribution System Topology and Equipment

Electricity is typically generated at relatively low voltages, in the range of 20 to 25 kilovolts ("kV") in major generating stations and immediately transformed up to higher voltages (115 kV, 230 kV and 500 kV) for transmission to load centres.

Figure 38: Simplified Generation/Transmission/Distribution Model



Source: PNXA

Transmission substations transform the voltage back down to typically 44 kV for bulk distribution of power via what are called sub-transmission or "M Class" feeders that supply distribution stations. Distribution stations further transform the voltage down to typically 8 kV for distribution feeder circuits that are used to supply customers. A simplified generation, transmission, and distribution system model is illustrated in Figure 38.

The transformation process then continues one further step down to the 600, 230 or 115 volt ("V") level used in customers' homes and businesses. This last transformation is done by pole-top or pad-mounted transformers located relatively close to the customers, as illustrated in Figure 39.

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Figure 39: Typical Single Phase Pole-Top Transformer

Source: PNXA files

The primary elements that make up a distribution system are the distribution feeders (lines or cables), distribution stations, and metering and control systems. However, each of these elements is comprised of many types of components. Overhead distribution lines, as illustrated in Figure 39, include aluminum primary conductors, porcelain or polymeric line insulators, fuses and fuse holders, pole-top transformers, secondary wiring, poles and pole hardware. Underground and submarine cables are used sparingly because they are significantly more costly than overhead lines. They include insulated primary cable, and pre-moulded terminations and splices.

Distribution stations vary in design and complexity depending on their location and the number of feeders connected by them. Figure 40 illustrates a typical open air distribution station.

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Figure 40: Typical Open Air Distribution Station

Source: PNXA files

Stations of this type include transformers, circuit breakers and/or re-closers, disconnect switches, grounding switches, bus conductors, protection, control and metering equipment, station cables to facilitate line entrances and exits, and structural elements. In built-up areas distribution stations may be enclosed in buildings or surrounded by improved appearance walls and other aesthetic treatments.

Power quality standards require that the voltage and frequency be maintained within prescribed limits. The frequency is controlled at the bulk transmission system level, however, voltage control is a concern on distribution systems. Current flowing on long distribution feeders causes a voltage drop along the feeder that is a function of loading. As well, loads with lagging power factors (inductive loads for example, motors, air conditioners, etc.) require reactive compensation in the form of capacitor banks which need to be switched in or out as required. Voltage regulators, such as the single phase unit illustrated in Figure 41, are in common use on long feeders to provide controlled voltage support when loads are high and series inductors to limit voltage levels when loads are low.

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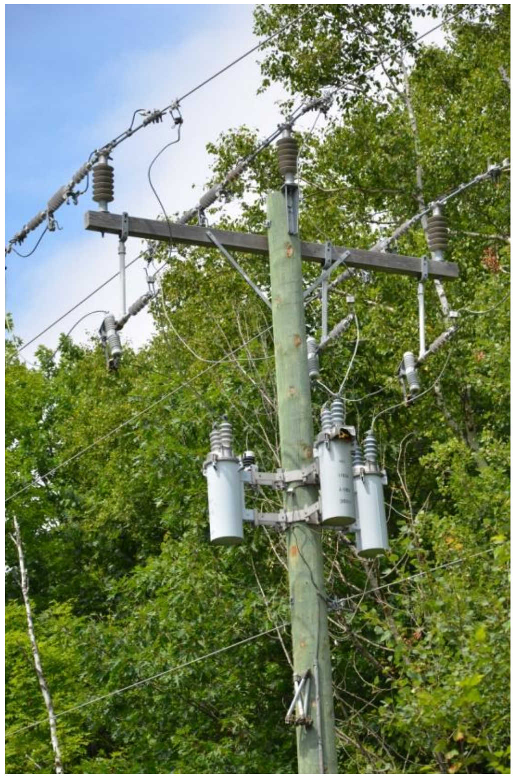
Figure 41: Single Phase Voltage Regulator (Left) and Three Phase Series Inductor (Right)



Source: PNXA files

<u>Operation and Maintenance of Distribution Systems</u>

Distribution infrastructure requires continual monitoring to ensure that the system is operating normally and within the prescribed operational limits. Loadings need to be monitored to ensure that currents and voltages are within equipment ratings, that loadings on the three phases of feeders are balanced, and that opportunities for lowering system losses and improving operational efficiencies are acted upon.

The condition of distribution station transformers needs to be monitored, circuit breakers and re-closers include moving parts which wear out and need to be replaced, wood poles rot and are attacked by insects and birds, and vegetation impinges on lines and needs to be removed or trimmed for safety and reliability concerns. In addition, failures and weather related outages occur, which require immediate action to repair because many cause customers to be without power for a period of time. The extent of operational maintenance and repair is influenced by the age of the infrastructure, the environment in the location in the province, and the geography of the location (e.g., heavily forested versus farm land). This latter factor also influences the topology of the system which affects work methods and accessibility.

The topology of distribution systems can vary considerably which may impact distribution operating and sustainment costs. Figure 42 is a snapshot view from HONI's GIS showing one of the distribution stations in the Bracebridge operating area and a number of feeders supplied from that distribution station, as well as the location of the transformers supplying customers on the feeders.

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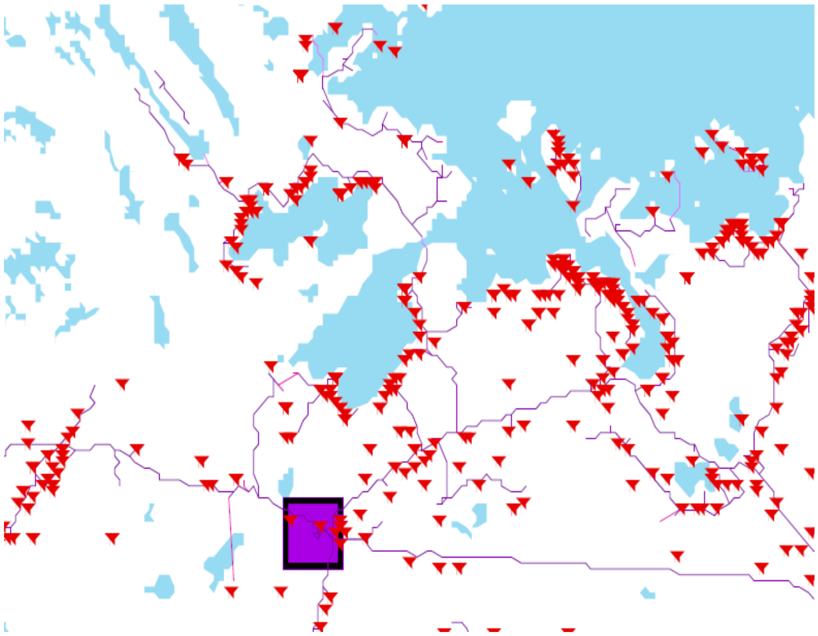
Figure 42: Typical Radial Feeder Topology in Northern Ontario



Notes: Feeders are shown as lines, triangles represent transformers feeding customers, and the purple rectangle indicates the distribution station
Source: HONI

In contrast, Figure 43 illustrates a typical feeder topology from the Simcoe operating area in southern Ontario. While both of these distribution systems are operated "radially" from the distribution stations, the grid-like regularity of the system in Simcoe offers opportunities for multiple interconnections of feeders, which in turn provides increased flexibility and operational reliability.[36] If the number of customers in a given area is large enough, most distribution utilities use a meshed system design (as shown in Figure 43) to reduce the number of customers affected by an outage and improve the reliability of supply.

36 A radial network consists of a series of "spokes" and "hubs". Distribution feeders leave a DS and pass through the network area with no normal connection to any other supply. This is typical of long rural lines with isolated load areas. An interconnected or "mesh" network is generally found in more urban areas and will have multiple connections to other points of supply. These points of connection are normally open but allow for various configurations through the opening and closing of switches.

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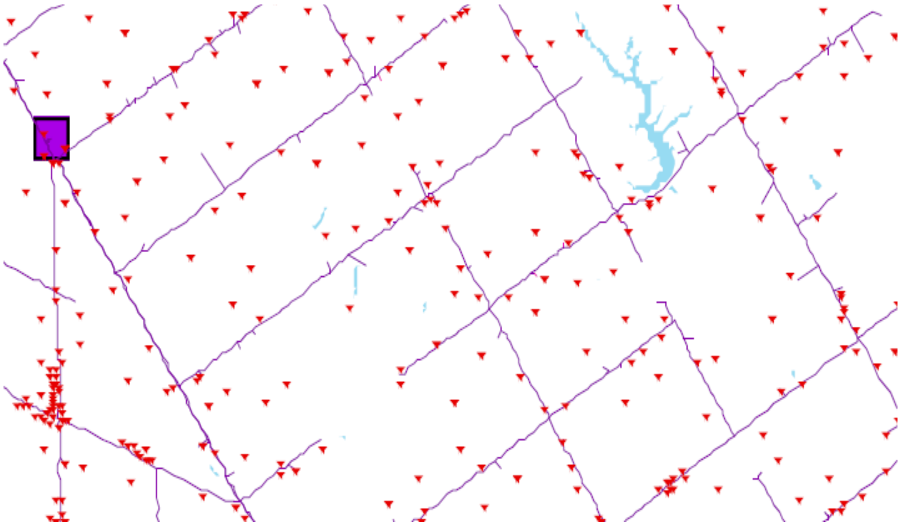
Figure 43: Grid-like Feeder Topology Typical in Southern Ontario



Notes: Feeders are shown as lines, triangles represent transformers feeding customers, and the blue rectangle indicates the distribution station
Source: HONI

In addition, feeders in the heavily forested and rocky areas may have greater off-road lengths, as illustrated in Figure 44, and require more rock and crib pole mounts, which are generally more difficult and costly to access and maintain.

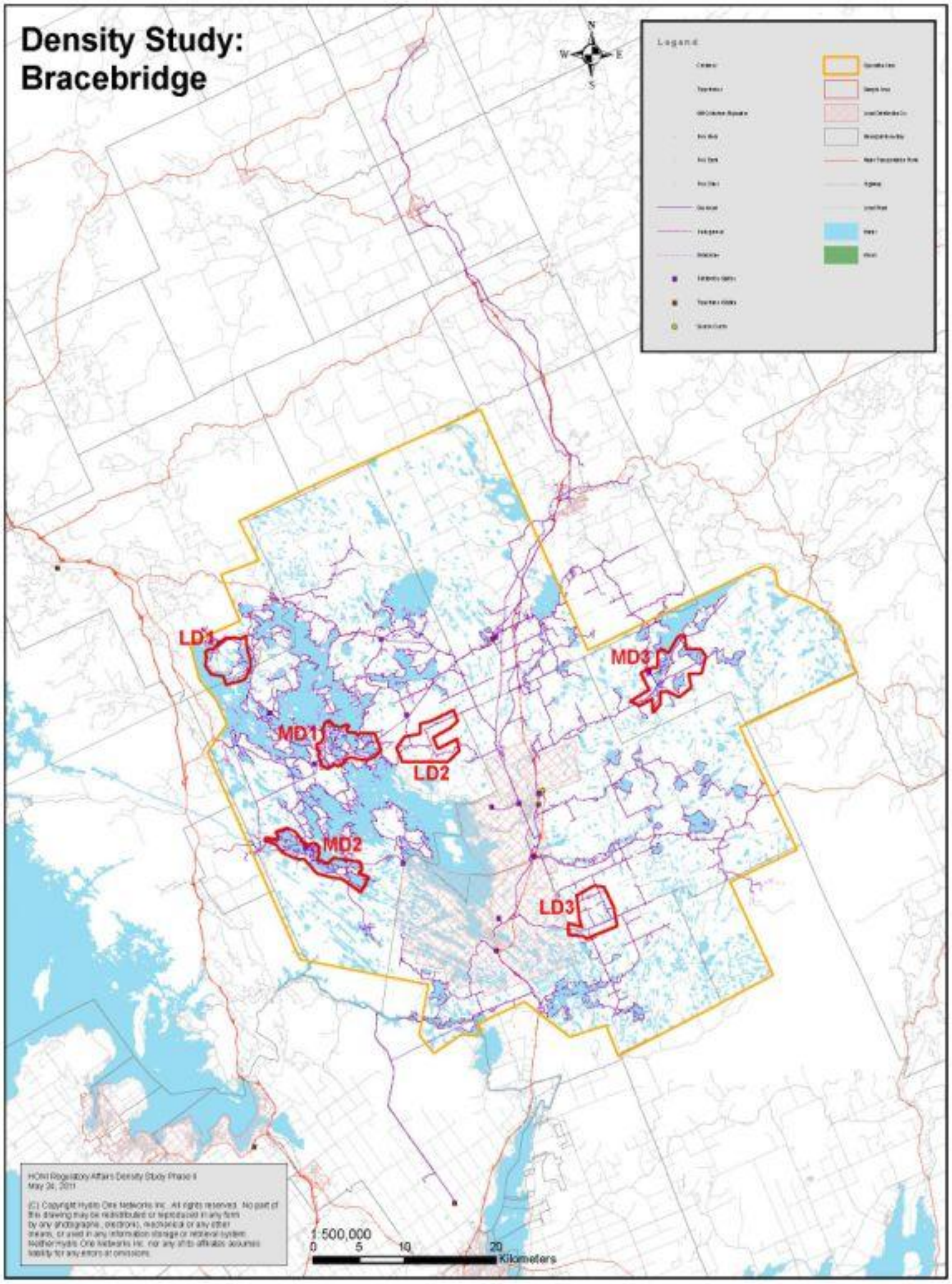
Figure 44: Typical Off Road Rights of Way

Source: PNXA files

Appendix C – Direct Cost Assignment Analysis Details

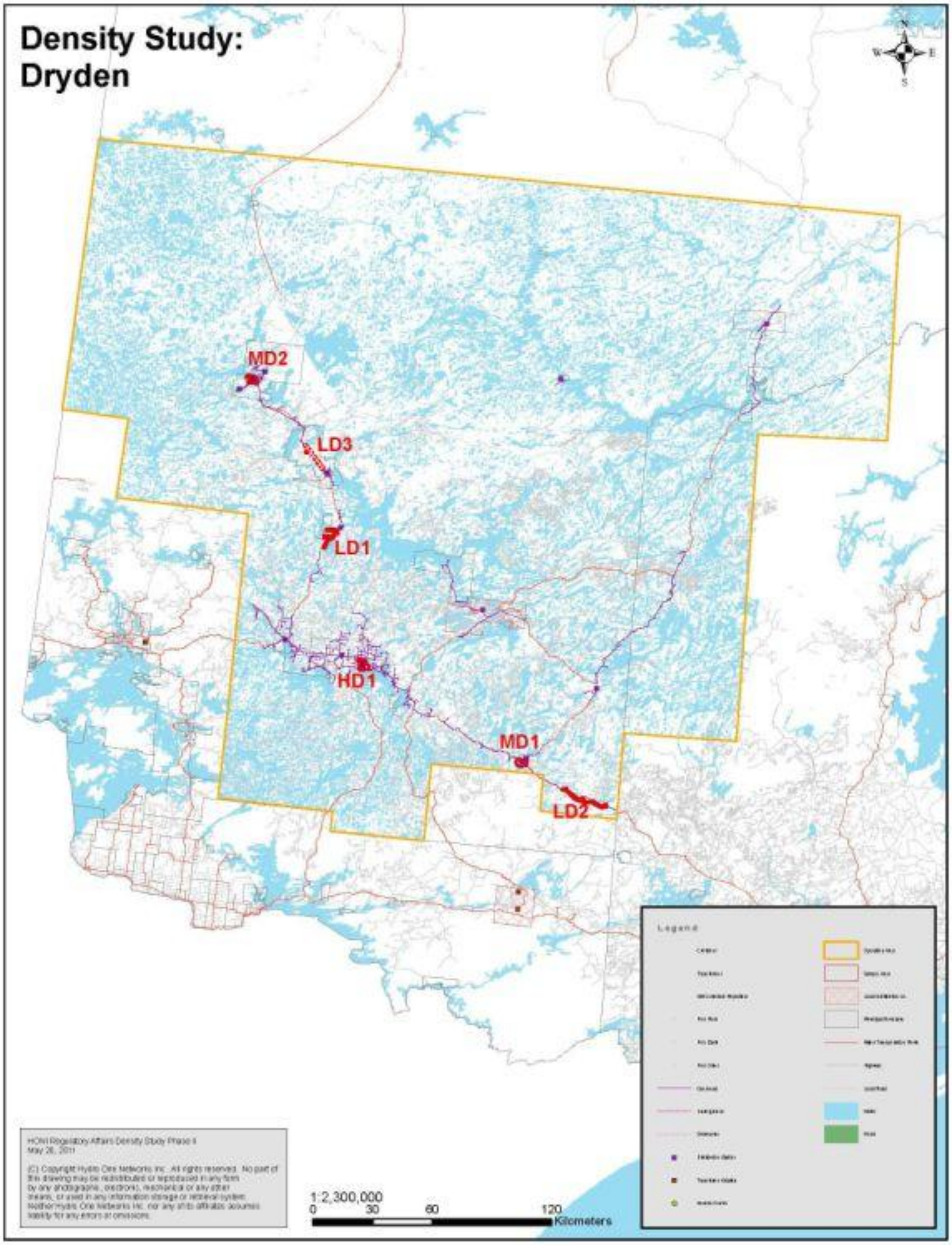
Sample Area Maps

Figure 45: Bracebridge Operating Area Map



Source: HONI

Figure 46: Dryden Operating Area Map



Source: HONI

Figure 47: Essex Operating Area Map

Source: HONI

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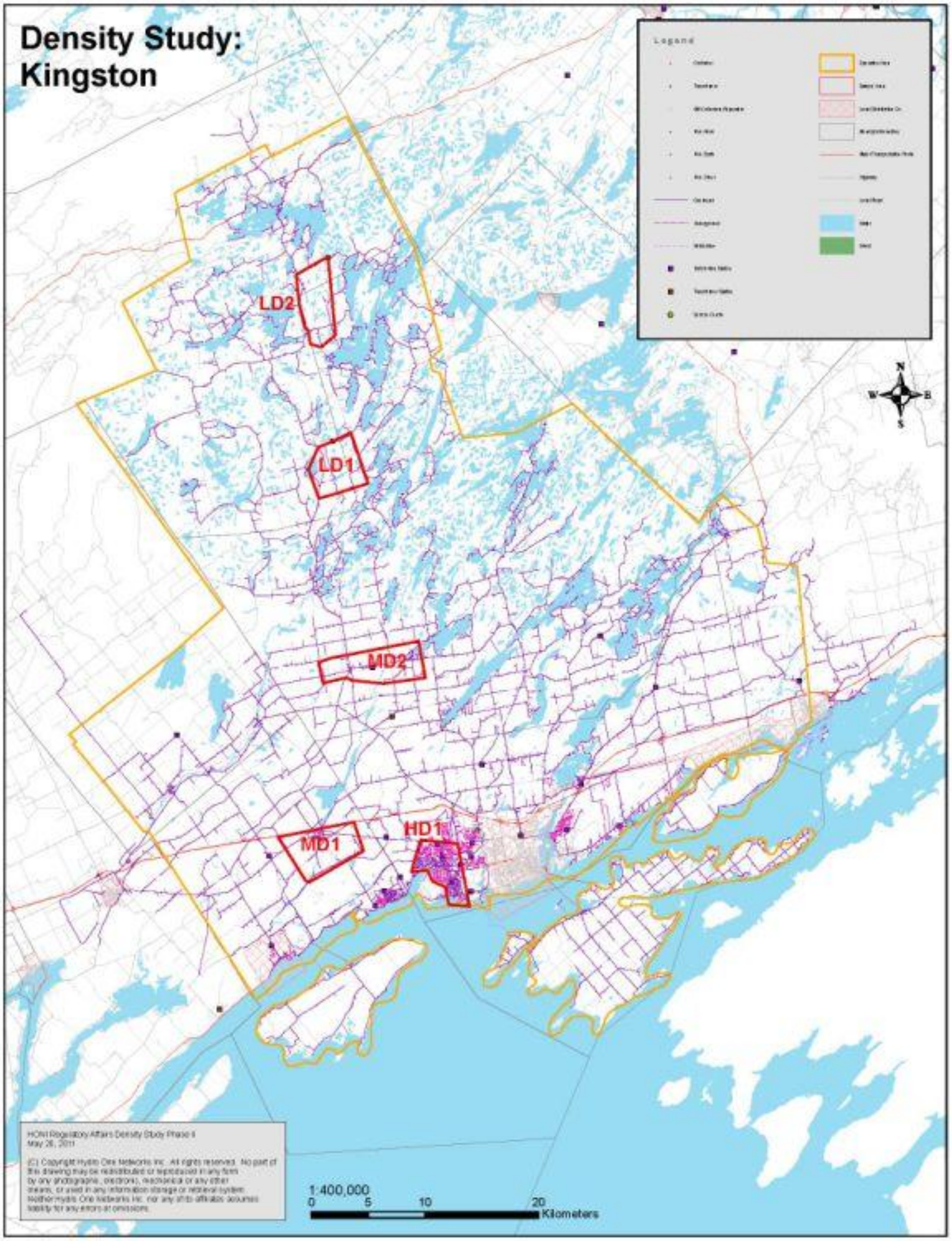
Figure 48: Kingston Operating Area Map



Source: HONI

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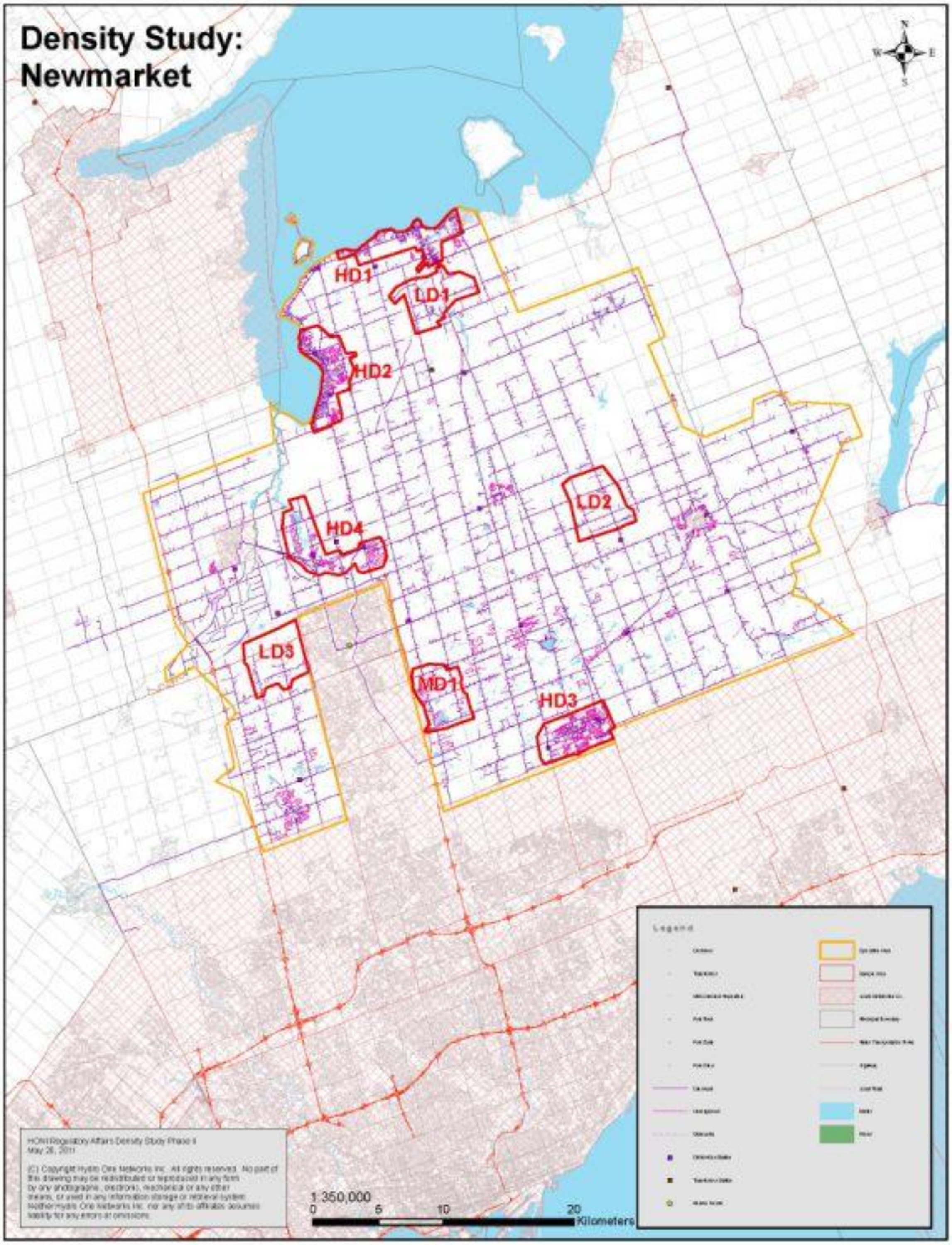
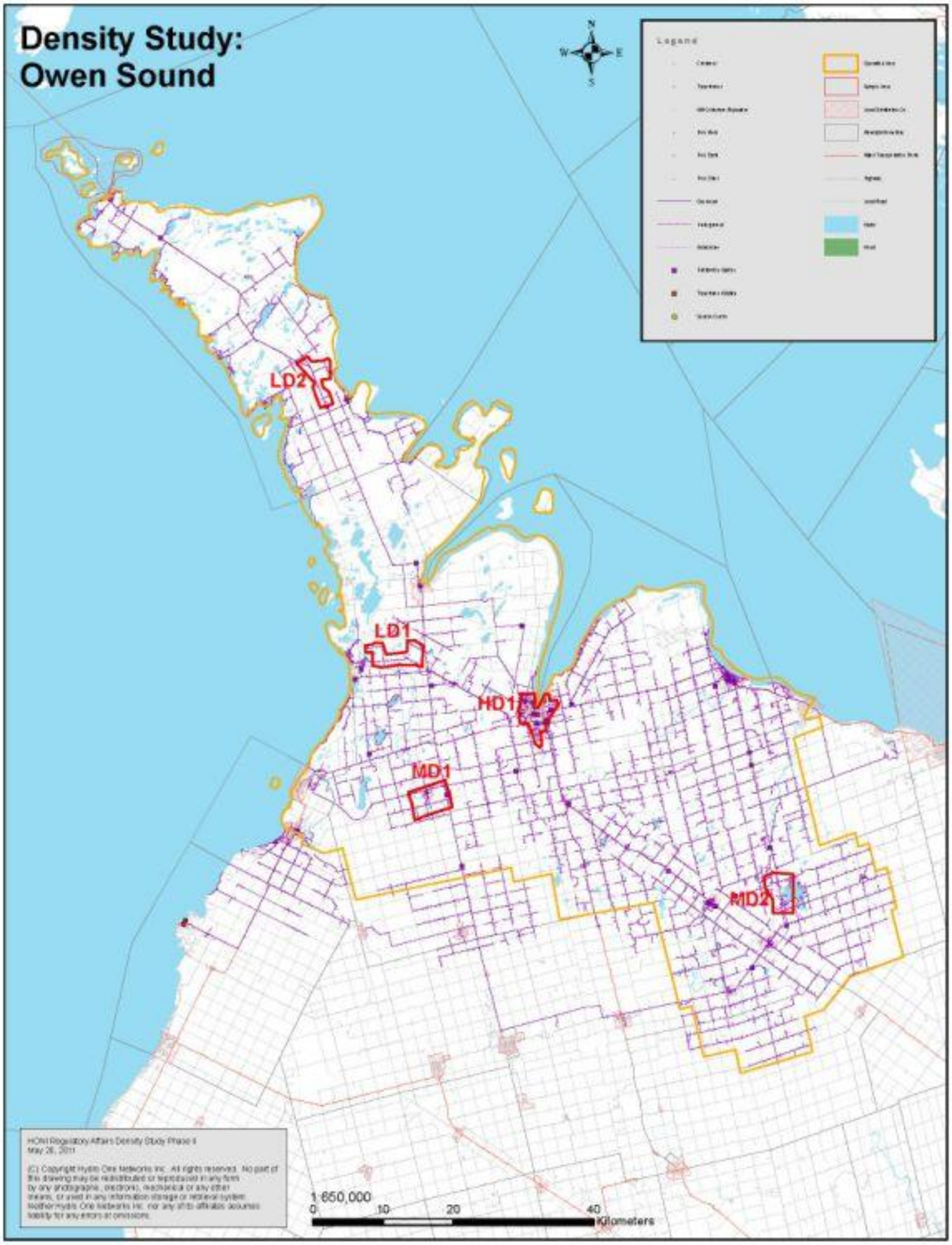
Figure 49: Newmarket Operating Area Map



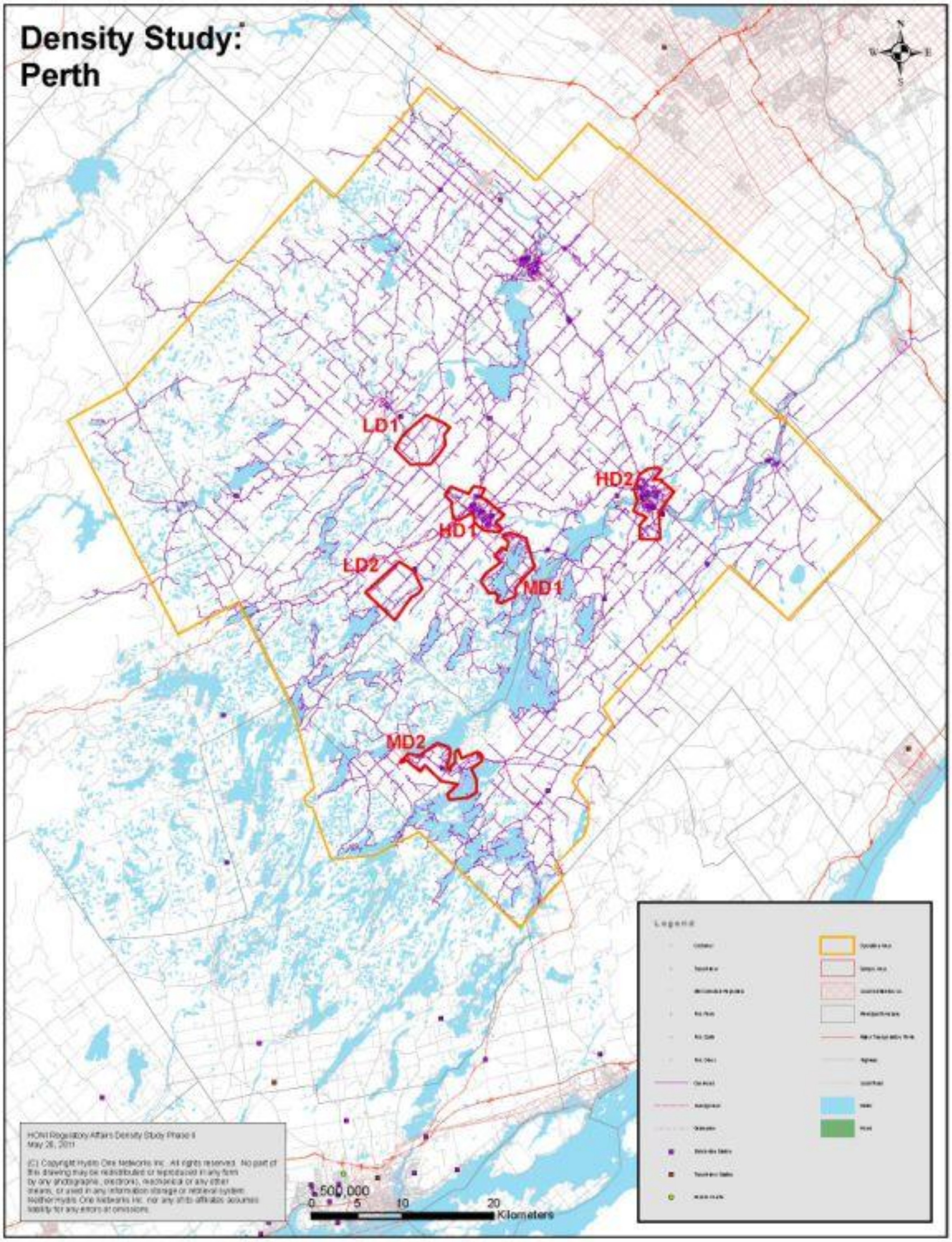
Source: HONI

Figure 50: Owen Sound Operating Area Map



Source: HONI

Figure 51: Perth Operating Area Map



Source: HONI

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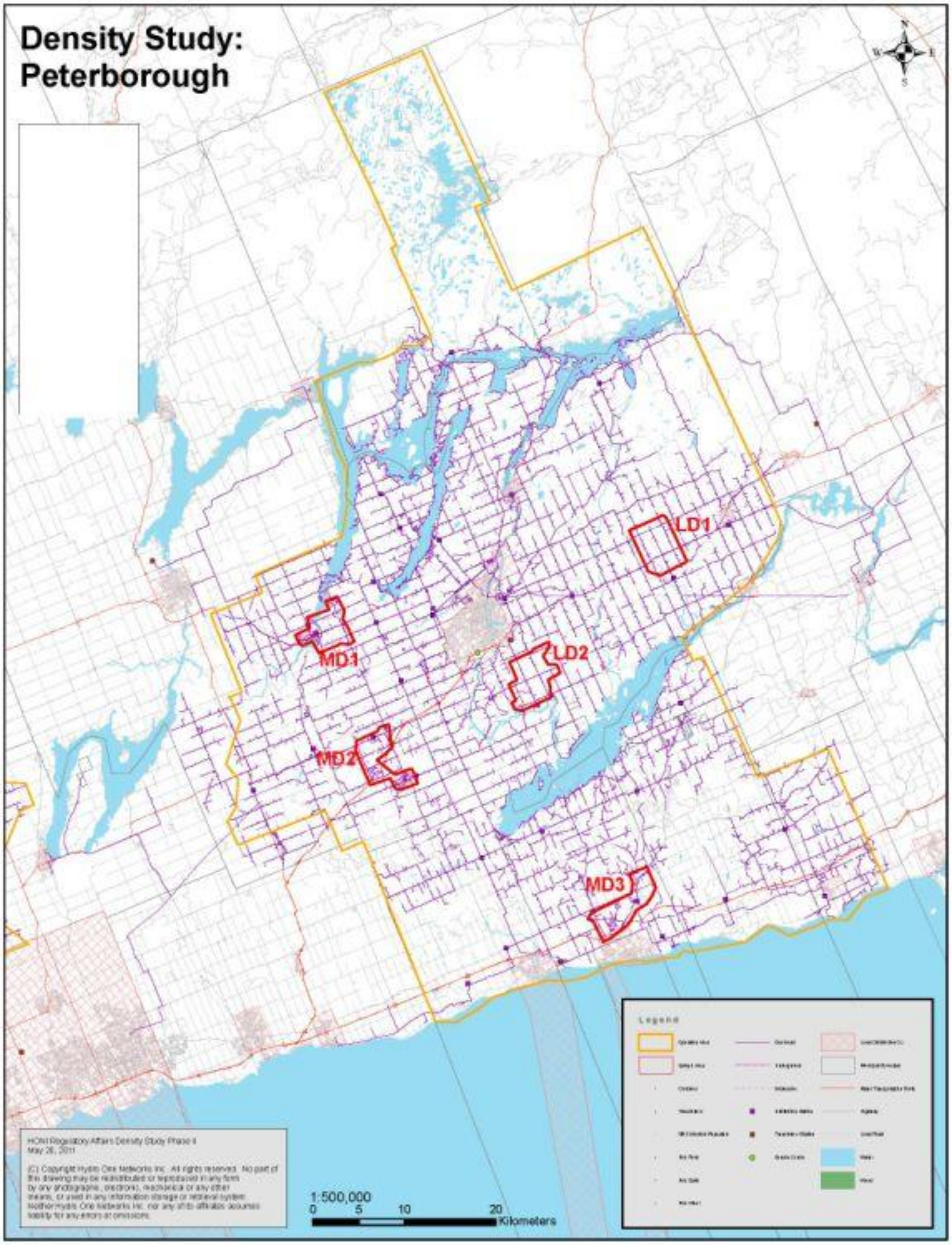
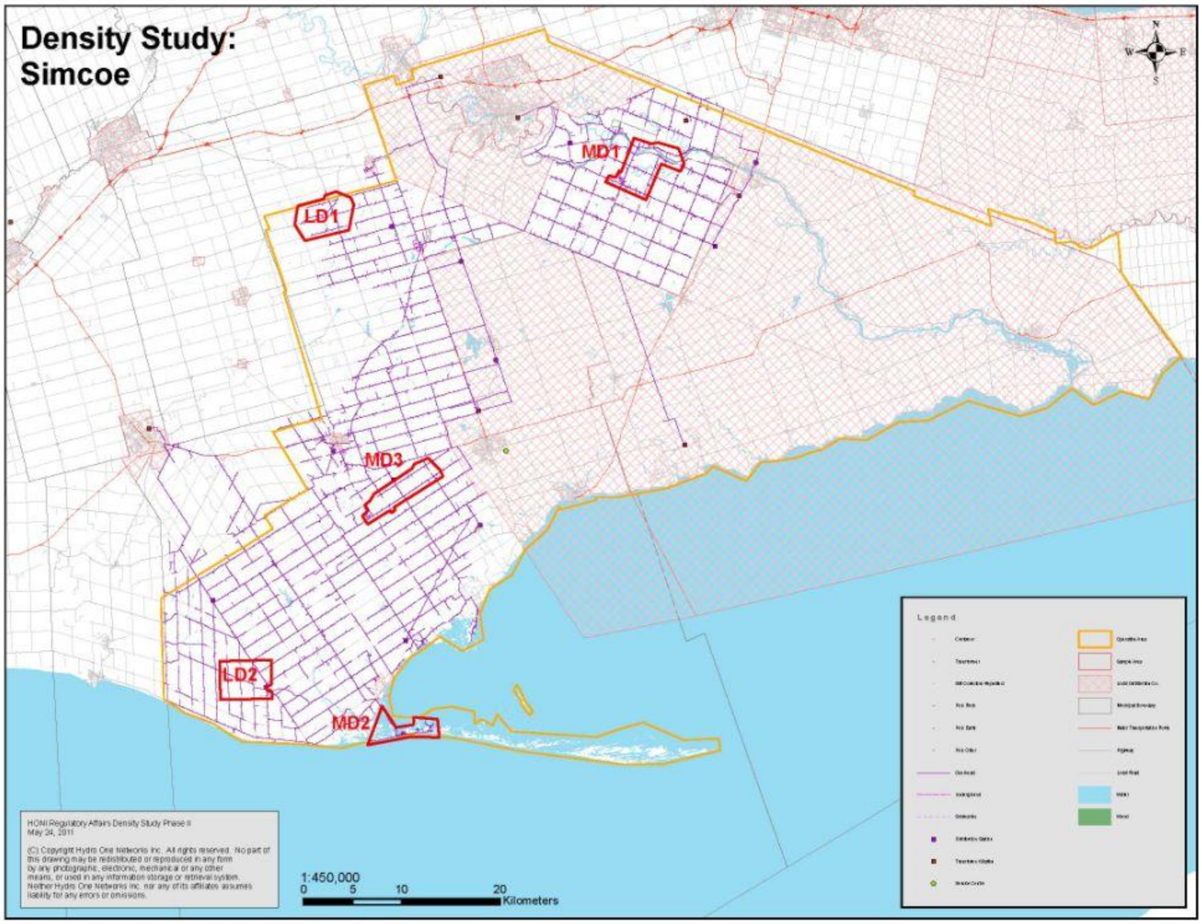
Figure 52: Peterborough Operating Area Map



Source: HONI

Figure 53: Simcoe Operating Area Map



Source: HONI

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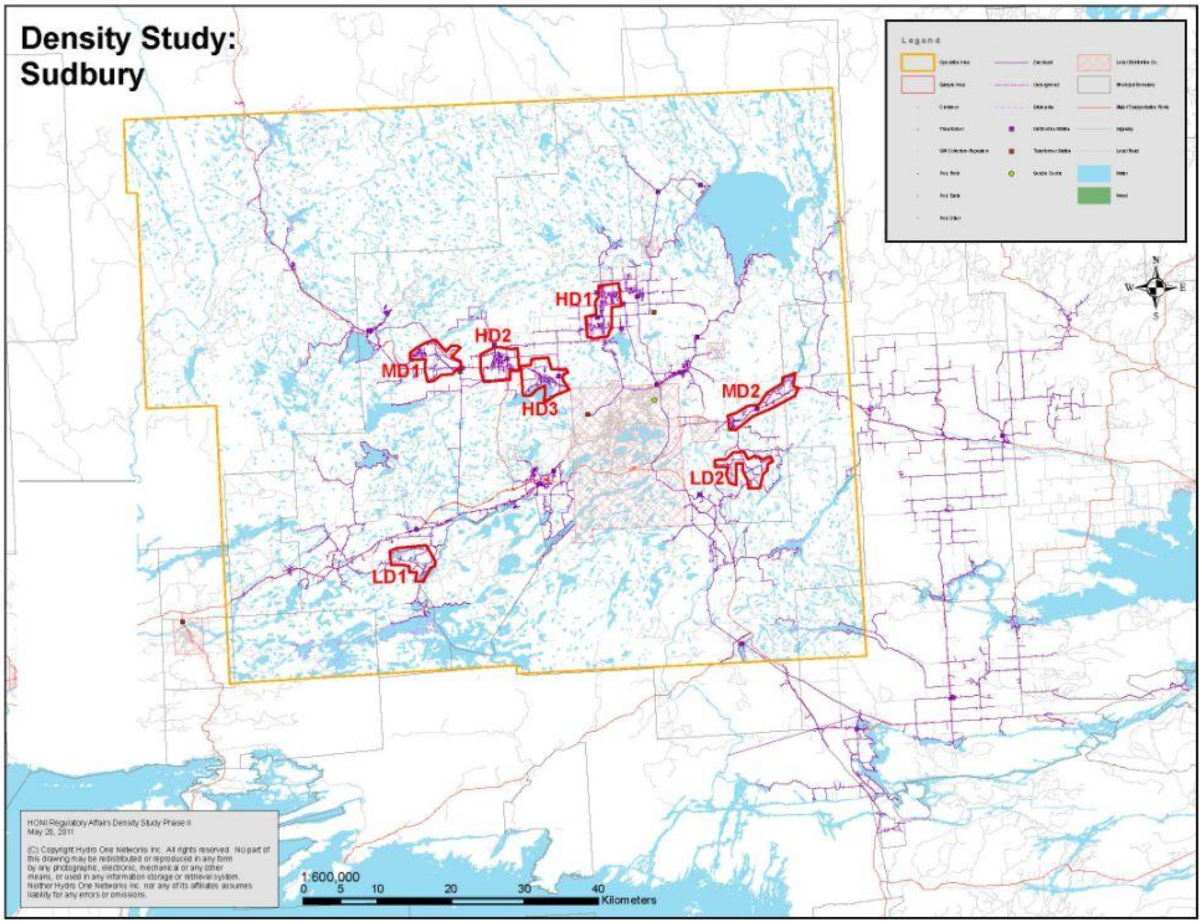
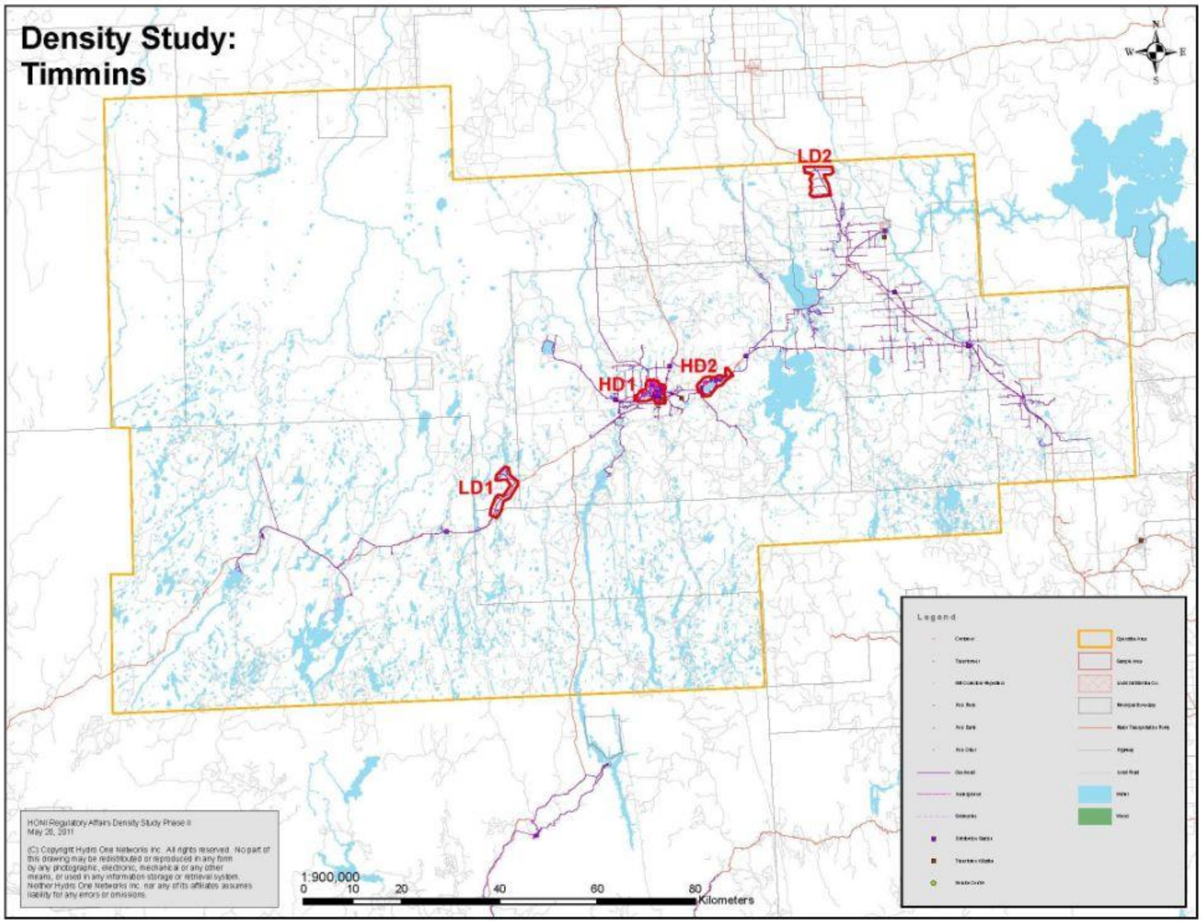
Figure 54: Sudbury Operating Area Map



Source: HONI

Figure 55: Timmins Operating Area Map



Source: HONI

Assignment Factor Calculation Methodology

Methodology for Calculating CRT:

- Obtain the number of customers in each sample area
- Obtain the total number of HONI customers
- Divide the number of customers in each sample area by the total number of HONI customers

Methodology for Calculating CROA:

- Obtain the number of customers in each sample area
- Obtain the number of customers in each operating area
- Divide the number of customers in each sample area by the number of customers in each operating area

Methodology for Calculating CDR:

- Calculate the total (aggregate) distance from each customer in a sample area to the closest service center
- Calculate the total (aggregate) distance from each customer in an operating area to the closest service center
- Divide the sample area total distance by the operating area total distance

Methodology for Calculating UGR:

- Calculate the total length of underground conductor in a sample area
- Calculate the total length of underground conductor in an operating area
- Divide the sample area total length by the operating area total length

Methodology for Calculating PDRT:

- Calculate the total (aggregate) distance from each pole in a sample area to the closest service center
- Calculate the total (aggregate) distance from each pole in an operating area to the closest service center
- Divide the sample area total pole distance by the operating area total pole distance

Methodology for Calculating IRNS:

- Calculate the total length of the distribution feeders that traverse a sample area
- Calculate the total length within the sample area of the distribution feeders that traverse the sample area
- Calculate the total number of non-storm related interruptions and non-interruptions associated with all of the distribution feeders that traverse a sample area
- Divide the total length of distribution feeders within the sample area by the total length of the feeders that traverse the sample area
- Multiply this ratio by the number of non-storm related interruptions and non-interruptions associated with the feeders

Methodology for Calculating IRS:

- Calculate the total length of the distribution feeders that traverse a sample area
- Calculate the total length within the sample area of the distribution feeders that traverse the sample area
- Calculate the total number of storm related interruptions and non-interruptions associated with all of the distribution feeders that traverse a sample area
- Divide the total length of distribution feeders within the sample area by the total length of the feeders that traverse the sample area
- Multiply this ratio by the number of storm related interruptions and non-interruptions associated with the feeders

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Individual Sample Area Assignment Factors

Figure 56: Individual Sample Area Assignment Factors (2010)

Operating Area	Sample Area	CRT	CROA	CDR	UGR	PDRT	IRNS	IRS
Bracebridge	LD1	0.000	0.008	0.014	0.009	0.018	0.017	0.018
Bracebridge	LD2	0.000	0.005	0.003	0.011	0.007	0.013	0.030
Bracebridge	LD3	0.000	0.006	0.004	0.011	0.008	0.008	0.002
Bracebridge	MD1	0.001	0.058	0.061	0.077	0.044	0.048	0.065
Bracebridge	MD2	0.001	0.073	0.087	0.002	0.062	0.069	0.051
Bracebridge	MD3	0.001	0.038	0.033	0.023	0.032	0.043	0.043
Dryden	LD1	0.000	0.008	0.009	0.000	0.014	0.012	0.000
Dryden	LD2	0.000	0.002	0.004	0.000	0.024	0.028	0.000
Dryden	MD1	0.001	0.071	0.113	0.033	0.036	0.026	0.000
Dryden	MD2	0.001	0.086	0.217	0.030	0.092	0.073	0.000
Dryden	HD1	0.003	0.295	0.014	0.364	0.004	0.105	0.000
Essex	LD1	0.000	0.005	0.003	0.000	0.007	0.009	0.002
Essex	LD2	0.000	0.005	0.006	0.000	0.014	0.022	0.016
Essex	MD1	0.001	0.026	0.045	0.016	0.031	0.026	0.045
Essex	MD2	0.001	0.027	0.021	0.020	0.020	0.015	0.003
Essex	HD1	0.002	0.066	0.072	0.079	0.034	0.042	0.077
Essex	HD2	0.002	0.058	0.075	0.147	0.034	0.028	0.021
Kingston	LD1	0.000	0.002	0.003	0.000	0.013	0.012	0.011
Kingston	LD2	0.000	0.002	0.004	0.000	0.013	0.014	0.022
Kingston	MD1	0.001	0.014	0.009	0.001	0.009	0.008	0.001
Kingston	MD2	0.001	0.018	0.015	0.008	0.015	0.014	0.028
Kingston	HD1	0.009	0.233	0.050	0.295	0.010	0.120	0.057
Newmarket	LD1	0.000	0.005	0.007	0.002	0.021	0.000	0.000
Newmarket	LD2	0.000	0.005	0.006	0.006	0.012	0.000	0.000
Newmarket	LD3	0.000	0.003	0.001	0.006	0.002	0.008	0.000
Newmarket	MD1	0.001	0.018	0.007	0.039	0.006	0.019	0.000
Newmarket	HD1	0.003	0.072	0.115	0.009	0.102	0.081	0.000
Newmarket	HD2	0.007	0.180	0.187	0.106	0.024	0.094	0.000
Newmarket	HD3	0.007	0.170	0.164	0.166	0.017	0.092	0.000
Newmarket	HD4	0.003	0.078	0.031	0.078	0.015	0.023	0.000
Owen Sound	LD1	0.000	0.002	0.002	0.013	0.004	0.002	0.000
Owen Sound	LD2	0.000	0.001	0.000	0.000	0.008	0.003	0.016
Owen Sound	MD1	0.000	0.013	0.013	0.015	0.008	0.022	0.001
Owen Sound	MD2	0.000	0.011	0.023	0.004	0.019	0.015	0.016
Owen Sound	HD1	0.008	0.215	0.022	0.090	0.003	0.082	0.018
Perth	LD1	0.000	0.002	0.001	0.000	0.003	0.006	0.002
Perth	LD2	0.000	0.003	0.002	0.008	0.004	0.006	0.019
Perth	MD1	0.001	0.021	0.008	0.034	0.006	0.019	0.017
Perth	MD2	0.000	0.014	0.020	0.010	0.017	0.012	0.008
Perth	HD1	0.003	0.098	0.007	0.202	0.002	0.054	0.000
Perth	HD2	0.004	0.138	0.129	0.063	0.040	0.085	0.002
Peterborough	LD1	0.000	0.003	0.004	0.000	0.008	0.008	0.000
Peterborough	LD2	0.000	0.004	0.002	0.000	0.003	0.011	0.000
Peterborough	MD1	0.001	0.025	0.024	0.018	0.011	0.016	0.000
Peterborough	MD2	0.001	0.031	0.027	0.048	0.011	0.016	0.000
Peterborough	MD3	0.001	0.032	0.009	0.003	0.017	0.023	0.000
Simcoe	LD1	0.000	0.010	0.014	0.006	0.016	0.008	0.000
Simcoe	LD2	0.000	0.008	0.013	0.001	0.022	0.023	0.011
Simcoe	MD1	0.001	0.060	0.068	0.090	0.040	0.008	0.006
Simcoe	MD2	0.001	0.060	0.083	0.075	0.022	0.012	0.021
Simcoe	MD3	0.000	0.029	0.015	0.001	0.009	0.000	0.000
Sudbury	LD1	0.000	0.004	0.007	0.004	0.025	0.021	0.037
Sudbury	LD2	0.000	0.003	0.002	0.004	0.008	0.009	0.009
Sudbury	MD1	0.001	0.028	0.037	0.010	0.042	0.021	0.012
Sudbury	MD2	0.001	0.024	0.013	0.003	0.017	0.019	0.007
Sudbury	HD1	0.004	0.138	0.081	0.187	0.036	0.079	0.017
Sudbury	HD2	0.003	0.099	0.089	0.061	0.046	0.068	0.021
Sudbury	HD3	0.002	0.060	0.000	0.047	0.027	0.042	0.011
Timmins	LD1	0.000	0.005	0.014	0.000	0.014	0.015	0.051
Timmins	LD2	0.000	0.002	0.006	0.003	0.025	0.011	0.033
Timmins	HD1	0.011	0.580	0.115	0.723	0.015	0.342	0.098
Timmins	HD2	0.002	0.132	0.101	0.102	0.024	0.085	0.047

Source: LEI and PNXA analysis

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Individual Sample Area Results

Figure 57: Low-Density Sample Area Results

Operating Area	Sample Area	OM&A	Asset Intensity
Bracebridge	LD1	277	23,817
Dryden	LD1	218	34,896
Essex	LD1	89	25,687
Kingston	LD1	346	12,548
Newmarket	LD1	155	23,732
Owen Sound	LD1	216	27,692
Perth	LD1	340	33,480
Peterborough	LD1	266	28,154
Simcoe	LD1	173	25,271
Sudbury	LD1	254	7,083
Timmins	LD1	245	24,733
Bracebridge	LD2	809	15,450
Dryden	LD2	1,868	45,610
Essex	LD2	228	27,043
Kingston	LD2	412	33,199
Newmarket	LD2	151	16,330
Owen Sound	LD2	307	33,400
Perth	LD2	401	21,384
Peterborough	LD2	222	26,749
Simcoe	LD2	425	34,298
Sudbury	LD2	656	33,591
Timmins	LD2	348	61,279
Bracebridge	LD3	524	32,374
Newmarket	LD3	170	22,397
	Average	379	27,925

Source: LEI and PNXA analysis

Figure 58: Medium-Density Sample Area Results

Operating Area	Sample Area		Asset Intensity
Bracebridge	MD1	342	13,601
Dryden	MD1	164	9,745
Essex	MD1	156	7,668
Kingston	MD1	83	9,493
Newmarket	MD1	111	8,707
Owen Sound	MD1	114	11,041
Perth	MD1	141	11,689
Peterborough	MD1	166	13,689
Simcoe	MD1	147	8,848
Sudbury	MD1	158	8,873
Bracebridge	MD2	165	18,338
Dryden	MD2	219	11,723
Essex	MD2	99	9,206
Kingston	MD2	103	7,353
Owen Sound	MD2	219	15,228
Perth	MD2	212	14,903
Peterborough	MD2	153	9,910
Simcoe	MD2	135	4,848
Sudbury	MD2	122	10,259
Bracebridge	MD3	150	13,232
Peterborough	MD3	103	6,950
Simcoe	MD3	168	12,113
	Average	156	10,792

Source: LEI and PNXA analysis

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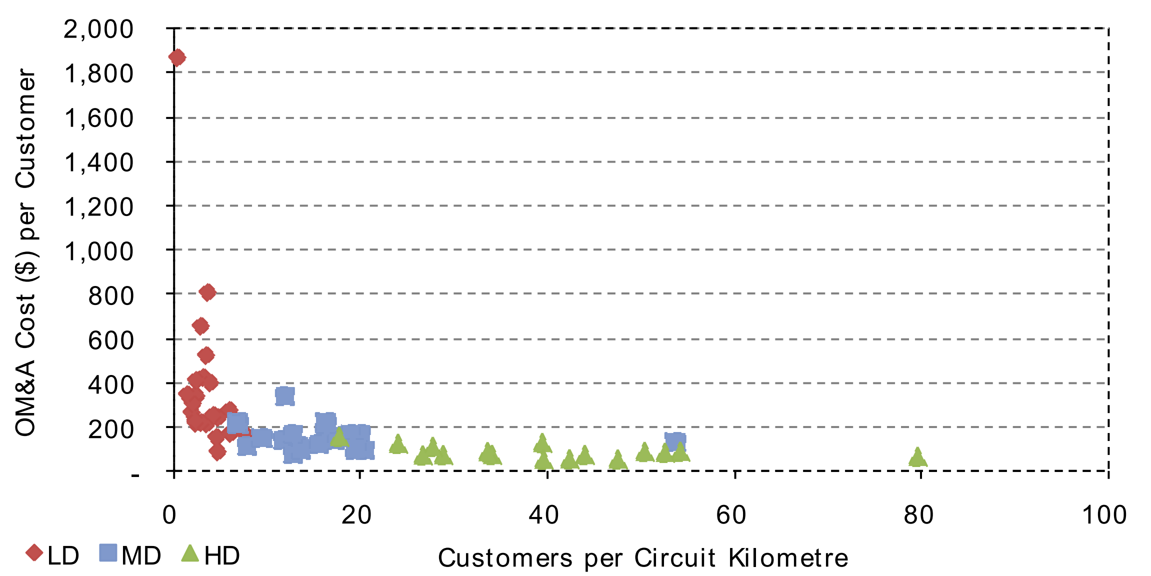
Figure 59: High-Density Sample Area Results

Operating Area	Sample Area	OM&A	Asset Intensity
Dryden	HD1	77	8,323
Essex	HD1	126	5,076
Kingston	HD1	57	2,882
Newmarket	HD1	130	9,037
Owen Sound	HD1	58	4,700
Perth	HD1	76	7,740
Sudbury	HD1	77	4,631
Timmins	HD1	69	2,709
Essex	HD2	157	4,451
Newmarket	HD2	87	3,773
Perth	HD2	113	7,136
Sudbury	HD2	90	4,946
Timmins	HD2	91	4,905
Newmarket	HD3	91	2,265
Sudbury	HD3	56	6,176
Newmarket	HD4	75	5,151
	Average	89	5,244

Source: LEI and PNXA analysis

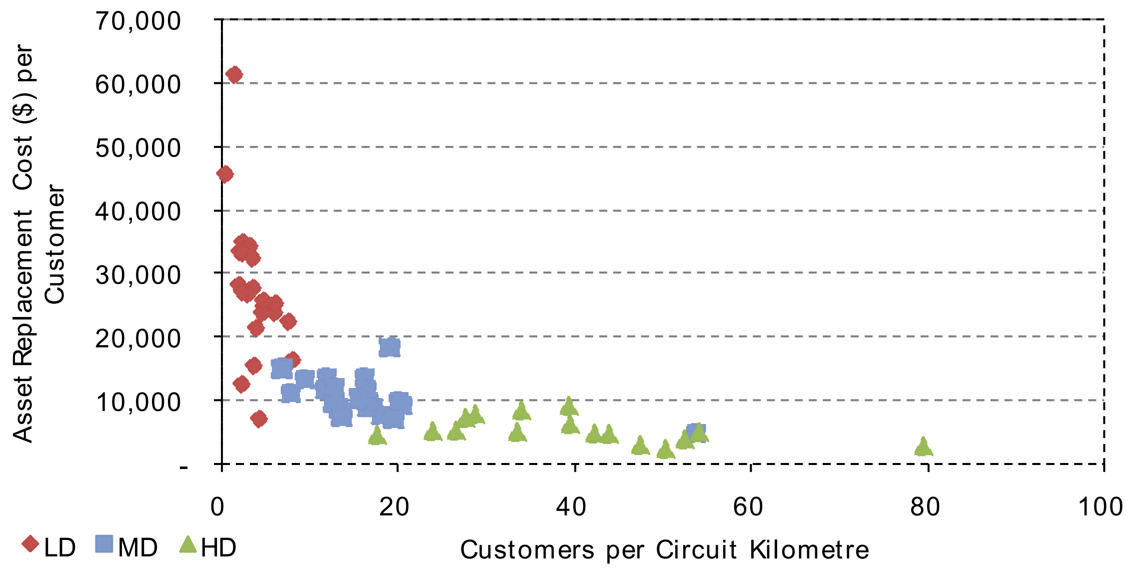
Additional Scatter Plots

Figure 60: Relationship between OM&A Costs and Customer Density (per circuit kilometre)



Source: LEI and PNXA analysis

Figure 61: Relationship between Asset Intensity and Customer Density (per circuit kilometre)

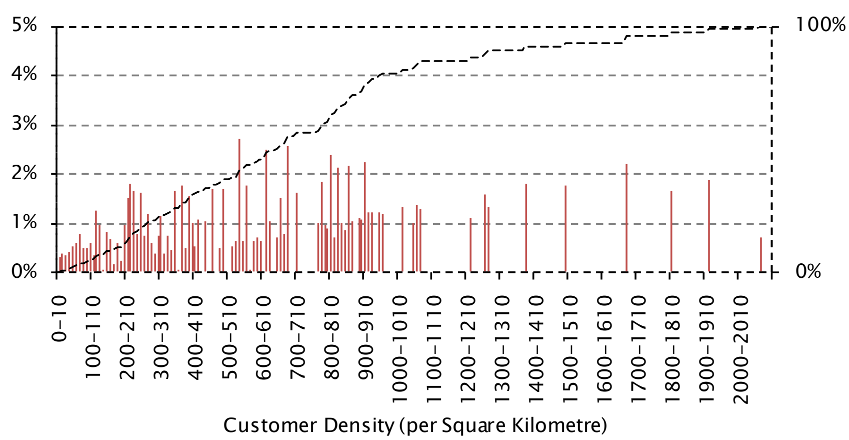


Source: LEI and PNXA analysis

Estimated Density of Existing Rate Classes

The following figures are based on data provided by HONI from the GIS. A grid consisting of one square kilometre cells was layered over the 11 operating areas included in the direct cost assignment analysis. The number of customers within an individual grid cell is equal to the density of the grid cell. Figure 62 through Figure 67 plot the probability and cumulative distributions of customer density for HONI's existing UR, R1, R2, Seasonal, Urban General Service (UGe and UGd), and General Service (GSe and GSd) rate classes, respectively.

Figure 62: Customer Density Distribution for HONI's UR Rate Class in 11 Operating Areas



Source: HONI; LEI and PNXA analysis

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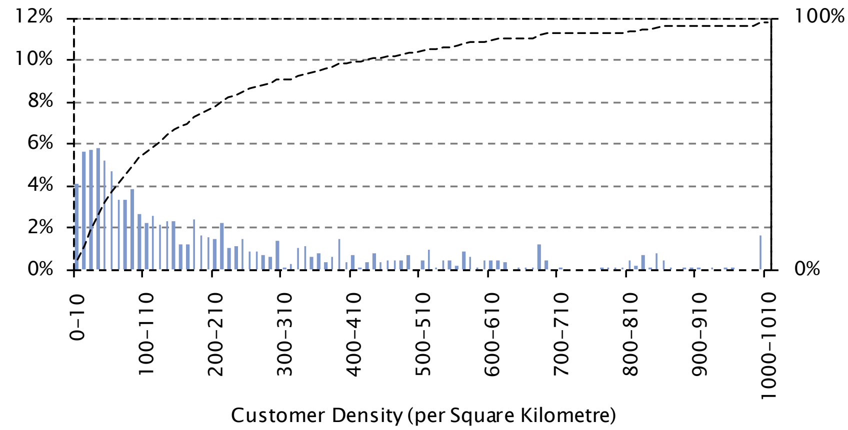
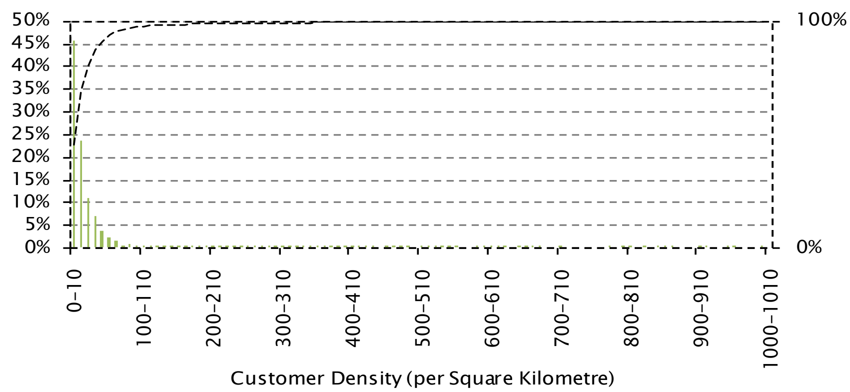
Figure 63: Customer Density Distribution for HONI's R1 Rate Class in 11 Operating Areas



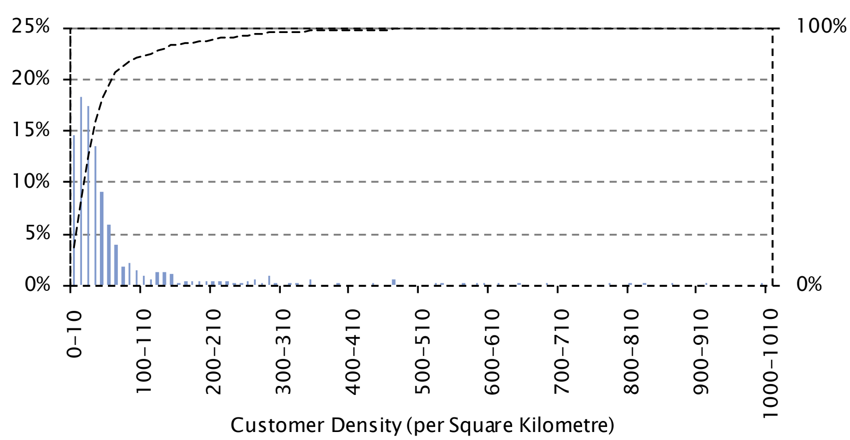
Source: HONI; LEI and PNXA analysis

Figure 64: Customer Density Distribution for HONI's R2 Rate Class in 11 Operating Areas



Source: HONI; LEI and PNXA analysis

Figure 65: Customer Density Distribution for HONI's Seasonal Rate Class in 11 Operating Areas



Source: HONI; LEI and PNXA analysis

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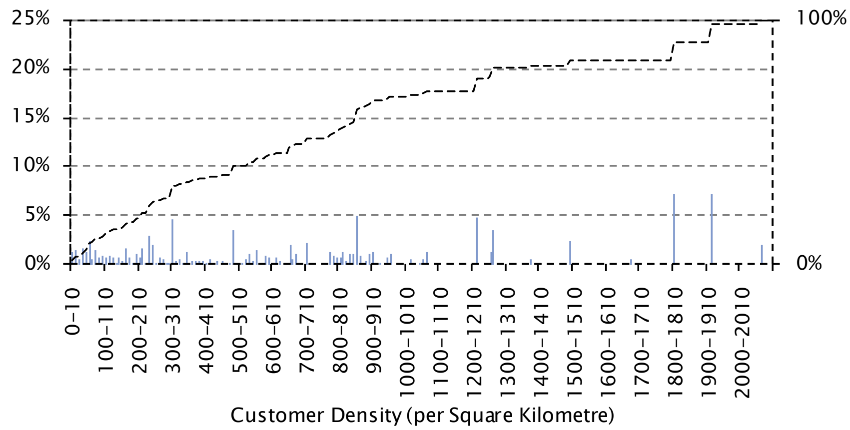
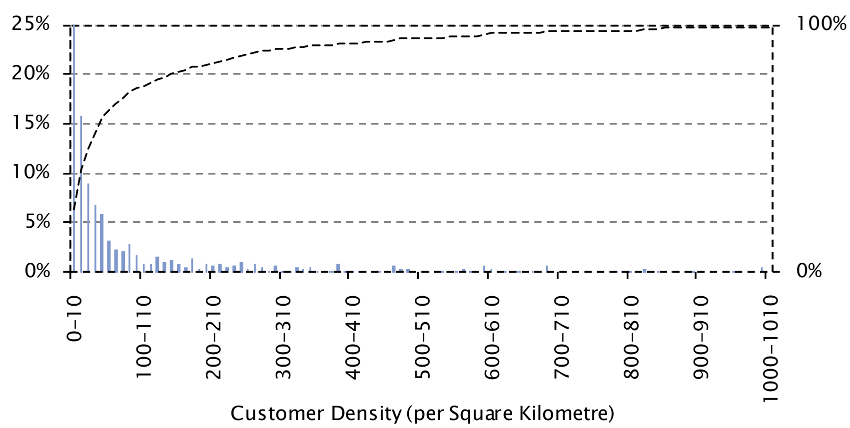
Figure 66: Customer Density Distribution for HONI's UGe and UGd Rate Classes in 11 Operating Areas



Source: HONI; LEI and PNXA analysis

Figure 67: Customer Density Distribution for HONI's GSe and GSd Rate Classes in 11 Operating Areas



Source: HONI; LEI and PNXA analysis

ATTACHMENT 1

<u>Template for External Expert Rule 13A Sign Off Document</u>

Note that the consultant may choose to provide a reference to where in the study report the relevant information is provided rather than repeat it in its entirety in the sign off document.

Title of Report:
Customer Density and Distribution Service Costs

Consultant:
Benjamin Grunfeld, *formerly* Managing Consultant, London Economics International LLC[1]

Qualifications:
See attached Curriculum Vitae

Instructions Provided:
See expert report, in particular pages 1-3

Basis of Evidence:
See expert report, in particular pages 4-31

Context of Evidence:
The evidence is provided as per OEB direction to Hydro One in a prior decision. This evidence was not provided in response to another expert's evidence.

Confirmation:
The expert has been made aware of and agrees to accept the responsibilities that are or may be imposed on the expert as set out in Rule 13A.

Signature:

Name of Expert: Benjamin Grunfeld

Date: August 23, 2012

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1 The study was conducted by London Economics International LLC. Benjamin Grunfeld was the project manager and lead investigator for this study when he was an employee of London Economics International LLC. He is currently an employee of Navigant Consulting Ltd.

Benjamin Grunfeld

Benjamin Grunfeld
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Professional History

- London Economics International; Managing Consultant; Toronto, Canada
- Ampersand Energy Partners; Senior Associate; Boston, USA
- Navigant; Senior Consultant; Toronto, Canada
- Hatch; Junior Engineer; Mississauga, Canada

Education

- M.Sc. Management and Economics; London School of Economics and Political Science; London, UK; 2008-2009
- B.Sc. Applied Mathematics and Electrical Engineering; Queen's University; Kingston, Canada; 1998-2003

Benjamin Grunfeld is an Associate Director in the Energy Practice at Navigant.

Benjamin provides strategic advice and analytical expertise to utilities, independent power producers, independent transmission companies, energy-related business ventures, governments, and arm's-length government agencies. He has considerable experience in the areas of energy policy design, power procurement, generation and transmission project development and finance, electricity market analysis and price forecasting, and utility regulatory economics. Benjamin has worked in regulated and deregulated markets across North America, as well as a range of developed and emerging economies around the world. He is responsible for all aspects of project fulfillment.

Prior to joining Navigant, Benjamin worked for London Economics International, a global economic, financial, and strategic advisory professional services firm, which specializes in energy, water, and infrastructure. He started his career as an engineer in the power and electro-technology group at Hatch.

Professional Experience

Transmission, Distribution, and Retail

» **Technical advisor to Ontario Distribution Sector Review Panel** – Provided technical consulting services to the Ontario Ministry of Energy in support of the Ontario Distribution Sector Review Panel. As part of this engagement, Benjamin managed a team providing insight on previous distributor mergers and quantification of associated savings, trends in distributor spending and implications on the potential for further efficiencies, cost drivers for LDCs and potential efficiencies, and areas where distributors are currently sharing common infrastructure, systems, and processes, and the potential for further efficiencies in these areas. *[Client: Ontario Ministry of Energy; Date: 2012; Location: Ontario, Canada]*

» **Customer density and cost allocation study –** Benjamin and his team were engaged by Hydro One Networks, Inc. to review the existing density-based rate class design and cost allocation mechanisms associated with the utility's electricity distribution business. The objective of the study is to establish a set of well-defined and defendable customer classes that take into account appropriate density differentiation. Benjamin led a consortium of firms providing econometric, engineering, and strategic advice to Hydro One Networks, Inc. in order to complete the study and assist with preparations for an upcoming rate application. Benjamin led two stakeholder engagement sessions. The first, to garner input into the methodology development, and the second, following the completion of the study, to present the results and findings. *[Client: Hydro One Networks, Inc.; Date: 2011; Location: Ontario, Canada]*

» **Due diligence support for potential investment in merchant transmission project -** Prepared three detailed presentations analyzing four proposed merchant high-voltage direct current transmission projects in the US. Analysis includes detailing the development roadmap and the current status of the proposed projects, identifying potential competitive threats from other similar competing transmission lines and local generation, and examining the renewable needs and willingness to pay of utilities on either end of the proposed transmission line. *[Client: Confidential (Independent Transmission Company); Date: 2011; Location: Multiple, USA]*

» **Drafting private placement memorandum for merchant transmission developer -** Drafted a private placement memorandum for a merchant transmission developer's Series B capital raise. Responded to investor queries in relation to market value of transmission services, financing arrangements, and competitive threats. *[Client: Confidential (Independent Transmission Company); Date: 2011; Location: Multiple, USA]*

» **Merchant transmission asset valuation and project development support -** Benjamin was the lead financial and market advisor to a US merchant transmission company developing to value a three-way high voltage direct current connection between the Eastern, Western, and Texas interconnections in the United States. Ben led a team to project energy prices in the markets surrounding the proposed project, including the Southwest Power Pool, the Western Electricity Coordinating Council, and the Electric Reliability Council of Texas regional markets. Ben was responsible for developing revenue forecasts for the project over a 20-year period; the project is subject to market-based rates. Ben also advising on other financing, regulatory, and development related issues. *[Client: Confidential (Independent Transmission Company); Date: 2010; Location: Multiple, USA]*

» **Analysis of competition in the Texas retail electricity market -** Prepared a white paper on competition in the Texas residential and commercial retail electricity market. Provided an overview of the structure of the retail electricity market (history, size, suppliers, elasticity of demand and customer switching), performed market share and Herfindahl-Hirschman Index analysis and evaluated the potential impact of a proposed merger. *[Client: Confidential (Retail Electricity Provider); Date: 2010; Location: Texas, USA]*

» **Electricity distribution tariff design -** Provided advisory support to the Electricity and Cogeneration Regulatory Authority for the Kingdom of Saudi Arabia. Ben assisted in the development of a long-term electricity tariff model and framework designed to achieve revenue sufficiency for the electricity sector as a whole for several regulatory periods from 2008 onwards. The tariff design embedded efficiency targets and incorporated a lifeline tariff for residential customers amongst other features. *[Client: Electricity and Cogeneration Regulatory Authority; Date: 2007-2008; Location: Saudi Arabia]*

» **Benchmarking of distribution utility customer care costs -** Part of a team that provided an independent assessment of the competitiveness of pricing for customer care services. Ben analyzed and assessed the relative complexity of retail and regulated market structures in the United States and Canada, and prepared an overview of service quality requirements in multiple jurisdictions relative requirements in master service agreement. In addition, Ben also provided a benchmarking analysis of United States and Canadian electricity and gas utility customer care related costs. *[Client: Confidential (Utility); Date: 2006; Location: Alberta, Canada]*

» **Retail electricity supply market-entry strategy -** Led the development of a long-term wholesale electricity price forecast and market assessment report. Formulated and presented a market-entry and project-development strategy. *[Client: Confidential (Retail Electricity Provider); Date: 2005; Location: Ontario, Canada]*

Multi-Segment

» **Industrial Energy Initiative program design –** Advised both the Ontario Power Authority and the Ontario Ministry of Energy on the development of the Industrial Energy Initiative (IEI), which effectively offers new and existing industrial load in the province premium rates for electricity. Advised on a number of program design issues including: appropriate tariff levels, the impact on other customer classes, eligibility criteria, and the role of energy efficiency, among other issues. *[Ontario Power Authority; Date: 2012; Location: Ontario, Canada]*

» **Forecast of Ontario wholesale and consumer electricity prices –** Benjamin led a team of three consultants providing a quarterly forecast of wholesale and consumer electricity prices to a retail electric provider with generation assets in Ontario. Analysis included a monthly five-year forecast of the Hourly Ontario Electricity Price ("HOEP") and the Global Adjustment ("GA"). *[Client: Confidential (Retail Electricity Provider); Date: 2011; Location: Ontario, Canada]*

» **Review of the Ontario market structure and recommendations for improvement -** Authored a report on the current electricity market structure in Ontario and develop a series of recommendations aimed at lowering the overall cost of electricity supply to consumers and improving the sector's effectiveness. Led a team of consultants analyzing three key issues: the rising cost of electricity supply; the imbalance in the supply mix, both in terms of the overall installed generation capacity and the relative proportion of baseload and intermittent resources; and the distortion of the wholesale market price signal. *[Client: Direct Energy Marketing, Ltd.; Date: 2011; Location: Ontario, Canada]*

» **Comprehensive assessment of the British Columbia power sector -** Ben and his team developed a comprehensive report outlining the dynamics of the British Columbia electricity sector, in particular on Vancouver Island. The report analyzed long-term supply demand dynamics as well as the evolution of the Province's transmission network. The report also incorporated a synopsis of the recently introduced green energy legislation and its potential impact on the sector. *[Client: Confidential (Independent Power Producer); Date: 2010; Location: British Columbia, Canada]*

» **Analyzing the cost of the Ontario Green Energy Act, 2009 -** Led a team that developed a comprehensive independent analysis of the potential cost associated with the Ontario Green Energy Act, 2009. The analysis included estimates of the cost to Ontarians of: generation procured under a renewable energy feed-in tariff program; interconnection of new renewable facilities; the development and implementation of a "smart grid"; and new conservation and demand management initiatives. The engagement also required Ben to respond to media requests and facilitate a media conference. *[Client: Official Opposition in Ontario; Date: 2009; Location: Ontario, Canada]*

» **New England wholesale and capacity price forecasting and market analysis -** Developed 20-year forecasts of wholesale electricity and capacity market prices in the Independent System Operator New England control region. The work supported the successful re-financing of two hydro-electric facilities, one run-of-river and one pumped storage. *[Client: Confidential (Independent Power Producer); Date: 2007; Location: New England, USA]*

» **Ontario wholesale and consumer price forecasting and market analysis -** Led the development of a long-term wholesale and consumer electricity price forecast and market assessment report. The report addressed the impact of supply-side announcements, including the Minister of Energy's Supply Mix Directive to the Ontario Power Authority. The study also discussed the impact of the delay in the retirement of Ontario's coal-fired capacity. *[Client: Exxon Mobil; Date: 2006; Location: Ontario, Canada]*

» **Integrated resource plan development support -** Led the development of a peak demand forecast for the Ontario Power Authority's Integrated Power System Plan. Tasks included: estimating the impacts of various conservation and demand management scenarios; developing an hourly forecast of energy and peak demand; estimating end-use contributions to peak demand; estimating potential conservation and demand management impacts, by end-use; developing weather normalization algorithms and methodologies to weather-correct/normalize historic load data; estimating the impact of a system-wide deployment of time-of-use meters and time-of-use pricing on Ontario demand. *[Client: Ontario Power Authority; Date: 2006; Location: Ontario, Canada]*

» **Ontario wholesale and consumer price forecasting and market analysis** - One of the primary authors of Navigant's semi-annual Ontario Market Assessment multi-client study. The assessment contains a detailed overview of the Ontario market, past and present. It includes an analysis of the implications of recent market developments and an outlook onto future developments. The report also contains a wholesale market price forecast and an in-depth analysis of the effective consumer (or blended consumer) price. As a major contributor to multiple Ontario Market Assessments, Ben authored multiple sections of the report and performed the detailed analysis that accompanies the assessment; developed the fuel cost, demand and supply forecasts, and many other forecast assumptions underpinning the wholesale market price forecast. Ben also developed the estimate of the blended consumer price including an estimate of the "Global Adjustment". *[Client: Multiple; Date: 2004-2006; Location: Ontario, Canada]*

» **Variance tracking for Ontario regulated price plan -** Responsible for tracking and interpreting the variance between the forecast and actual Regulated Price Plan supply costs. Developed numerous summary and explanatory documents for both internal and public consumption. Developed the template for the "Monthly Variance Explanation" document posted monthly to Ontario Energy Board website. *[Client: Ontario Energy Board; Date: 2005-2006; Location: Ontario, Canada]*

» **Integrated resource plan development support -** Performed analysis and provided support during the development of the Ontario Supply Mix Advice. Aided in the preparation and delivery of a seminar on modeling alternatives for portfolio analysis, highlighting available tools and resources. Developed an Excel based model to quantify portfolio costs and risks for the Ontario Power Authority's report to the Ministry of Energy on the long term supply of electricity generation resources. Additional tasks included: developing a model to assess the peak demand impacts of conservation and time-of-use initiatives: developing conservation and smart meter load profile decrements for use within the portfolio evaluation model; developing a method for modeling weather impacts on base demand and conservation decrements. *[Client: Ontario Power Authority; Date: 2005-2006; Location: Ontario, Canada]*

» **Regional wholesale and consumer price forecasting and market analysis -** Led the development of a comprehensive assessment of the Ontario, Michigan, New York and Quebec electricity markets. The assessment included a Political-Economic-Socio-cultural-Technological analysis for Ontario and the neighbouring markets combined. The report provided a long-term price forecast for Ontario and neighbouring US jurisdictions. Highlights of the report include a discussion of new supply initiatives, planned retirements, fuel price assumptions, and an overview of the available markets in each jurisdiction. *[Client: Confidential (Independent Power Producer; Date: 2005; Location: Ontario, Canada]*

- **Default supply pricing mechanism design and implementation -** Part of a team that provided consultancy services throughout the design and implementation of the Regulated Price Plan for provincial electricity consumers. Implementation included: developing the requisite forecasts for the Ontario wholesale electricity market; describing the precise methodology used to blend the costs from the various streams that contribute to the Regulated Price Plan supply; deriving final prices that consumers are charged under the Regulated Price Plan; and developing the final documents available for public consumption. Ben developed the blended cost model, which ultimately determined the rate passed on to consumers, assessed the impact of regulatory decisions, developing the two tier rates for conventional metered facilities as well as the three tier pricing structure for time-of-use metered facilities. Modeled the effect of a price-tier threshold adjustment on the generated revenues, determined offsetting adjustment required to maintain revenue neutrality. Analyzed the key risk factors and sources of variance associated with the generated revenues and cost of supply for the Regulated Price Plan. *[Client: Ontario Energy Board; Date: 2004-2005; Location: Ontario, Canada]*

Renewable Power Generation

- **Hydro-electric generation facility valuation** – Managed a team providing market expertise to a bidder involved in a British Columbia-based hydro-electric asset auction process. The team reviewed pertinent documents, provided forecasts of expected power prices at the Mid-Columbia hub in the US, assessed the facilities' eligibility under the BC Hydro Standing Offer Program, examined the potential for additional contract concessions to support expansion of the facility, and provided estimates of the value of the facility beyond the initial contract term. *[Client: Confidential Independent Power Producer); Date: 2012; Location: British Columbia, Canada]*
- **Curtailment study for wind and other renewable generation in Ontario –** Benjamin led a multi-client study analyzing curtailment risk and the impact of proposed market rule changes on wind and solar power generation facilities in Ontario. *[Client: Multiple (Independent Power Producers); Date: 2012; Location: Ontario, Canada]*
- **Design of renewable energy procurement mechanisms and procurement vehicle for the Kingdom of Saudi Arabia –** Benjamin was the project manager for a multi-million dollar engagement with the King Abdullah City for Atomic and Renewable Energy ("K.A.CARE") to develop a renewable energy procurement framework. The procurement framework consisted of a standard design for renewable energy competitive solicitations, a feed-in tariff program, a sustainable energy procurement company, and a strategy for leveraging the procurements to achieve a desired level of local economic impact. Benjamin led a multi-faceted on-the-ground team consisting of local and global industry experts, economists, financial analysts, engineers, and legal advisors. *[Client: King Abdullah City for Atomic and Renewable Energy; Date: 2012; Location: Saudi Arabia]*
- **Evaluation of applications under the Ontario Aboriginal Renewable Energy Fund -** Led a team of three consultants providing desktop due diligence reviews of project applications received by the Ontario Power Authority under the Aboriginal Renewable Energy Fund. The team reviewed each application for eligibility, development risk (grid connectivity, property and resource control, and management experience), resource availability, technological risk, and economic return. *[Client: Ontario Power Authority; Date: 2011; Location: Ontario, Canada]*
- **Independent monitor for renewable energy procurement -** Acted as the fairness monitor for the Ontario Power Authority's evaluation of "launch period" feed-in tariff program applications. The

team aided in the design of the evaluation framework and provided on-going support during the evaluation process. Performed a mock evaluation in parallel with the Ontario Power Authority as a method of auditing the results. Ben and his team also prepared a final report that outlined the team's opinion as to the fairness of the overall process. *[Client: Ontario Power Authority; Date 2010; Location: Ontario, Canada]*

» **Due diligence for proposed purchase of German hydro-electric assets -** Prepared a comprehensive market review and indicative price forecast for the German power pool. Provided an overview of the German electricity market, including: market and institutional structure, supply, demand, and the transmission system and topography. Also considered the impact of nuclear retirements on supply and pricing. *[Client: Confidential (Independent Power Producer); Date: 2010; Location: Germany]*

» **Development support and market analysis for solid waste to energy project -** Prepared a comprehensive 15-year assessment of the Alberta wholesale power market, regional environmental attribute markets (greenhouse gas, renewable energy certificates, etc.), and Alberta natural gas markets for the developer of a municipal solid waste gasification and energy conversion facility in Red Deer, Alberta. The team provided strategic advice on the negotiation of power purchase agreements, de-risking activities, and the general development landscape for renewable power generation projects in the province. *[Client: Confidential (Independent Power Producer); Date: 2010; Location: Alberta, Canada]*

» **Modern portfolio theory and implications for hydro-electric portfolio performance -** For a hydro-electric generation developer, Benjamin hosted a workshop on the benefits of modern portfolio theory in the strategic development of an acquisition and development pipeline. The workshop outlined risks associated with hydro-electric generation assets such as hydrology, market price, technology, regulatory, development, etc. and the benefits that could be achieved through appropriate diversification. In particular, Ben and his team analyzed an actual acquisition pipeline, being targeted as part of a larger Initial Public Offering, and quantified the risk/return profile of the diversified portfolio relative to individual assets. *[Client: Confidential (Independent Power Purchaser); Date: 2010; Location: Multiple, Worldwide]*

» **Design of the Ontario Aboriginal Renewable Energy Fund -** Advised on the establishment of the Aboriginal Renewable Energy Fund. Provided an estimate of development costs for various renewable technologies and sizes and reviewed provincial and local approval requirements. Contributed to the development of the overall fund framework, including eligibility criteria, application requirements, and monitoring processes. *[Client: Ontario Power Authority; Date: 2010; Location: Ontario, Canada]*

» **Design of the Ontario Municipal Renewable Energy Program -** Advised on the establishment of the Municipal Renewable Energy Fund. Provided an estimate of the impact costs to municipalities hosting costs for various renewable technologies and sizes. Contributed to the development of the overall fund framework, including eligibility criteria, application requirements, and monitoring processes. *[Client: Ontario Power Authority; Date: 2010; Location: Ontario, Canada]*

» **Financial and technical due diligence for biomass-fired power plant refurbishment -** Led the due diligence and coordinated the preliminary design efforts for a comprehensive refurbishment and expansion of a biomass-fuelled power generation facility. *[Client: Confidential (Independent Power Producer); Date: 2010; Location: Vermont, USA]*

» **Strategic review of power generation assets -** Conducted a comprehensive strategic review of the company's extensive (> 400 megawatt) existing power-generation assets (primarily multi-fuel/biomass). *[Client: Confidential (Industrial); Date: 2010; Location: Multiple, USA]*

- **Financial valuation and due diligence of wind power generation project -** Performed financial due diligence and developed the financial model for a potential investment in a wind generating facility on behalf of an Ontario distribution utility. Analyzed the reasonableness of the developer's assumed capital and operating costs; interconnection requirements; projected revenue; plant performance and technical characteristics; and financial structure. Ben provided a working model, due diligence questions, and developed a framework for analyzing the potential risks associated with the investment. *[Client: Confidential (Utility); Date: 2009; Location: Ontario, Canada]*
- **Financing and project management of biomass power plant refurbishment -** Provided ongoing support towards the $35 million dollar financing of two 12.5 megawatt biomass-to-energy facilities in the central valley region of California. Involved in all aspects of the project's development including the review and negotiation of key contract documents (power purchase agreements, fuel supply contracts, refurbishment contracts, purchase and sale agreements, operations and maintenance agreements), environmental permitting (air, water, land use, community approval), and the negotiation and placement of equity and debt financing. *[Client: Confidential (Independent Power Producer); Date: 2006-2008; Location: California, USA]*
- **Construction management of biomass power plant refurbishment -** Oversaw the $35 million dollar refurbishment of two 12.5 megawatt biomass-to-energy facilities in the central valley region of California. Managed the interactions with regulators, fuel suppliers, power purchase agreement counterparty, operating company, and all other contract counter parties. Acted as Owner's Representative with regards to the management and supervision of construction activities. Managed and oversaw design and engineering, procurement of equipment, negotiation of sub-contractor contracts, and quality control and quality assurance. Responsible for the overall project budget and schedule. *[Client: Confidential (Independent Power Producer); Date: 2006-2008; Location: California, USA]*
- **Hydro-electric power purchase agreement negotiation support -** Assisted with the design and negotiation of power purchase agreements for hydro-electric generation resources. Primary role was to develop incentive mechanisms to promote shifting of output into on-peak periods and efficient cost management under the quasi-regulatory contract structure. *[Client: Ontario Power Authority; Date: 2008; Location: Ontario, Canada]*
- **Renewable energy sector growth strategy -** As part of a multi-firm engagement, led a team providing a comprehensive analysis of the financial, regulatory and business environment for renewable technologies in the United States for a diversified European investor looking for global investment opportunities. Provided an assessment of the relative costs of technologies such as biomass, solar, wind, and hydro. The analysis included review of federal and state tax benefits for renewable projects, assessment of mid-term prospects of electricity sector development and 10-year forecast of key wholesale electricity markets with focus on revenue potential for wind, solar, biomass and other renewable power plants. *[Client: Confidential (Industrial); Date: 2007; Location: Multiple, USA]*
- **Design of standard offer/feed-in tariff program -** Advised on various issues associated with the design of its initial renewable energy standard offer program, including: rationale for a standard offer; eligibility criteria; contract term; different approaches for establishing the standard offer price; and alternative incentive mechanisms for promoting on-peak generation. *[Client: Ontario Power Authority; Date: 2005-2006; Location: Ontario, Canada]*

Conventional Power Generation

- **Power-PPA value assessment** – Benjamin provided an assessment of the post-PPA value of a combined cycle gas turbine (CCGT) facility in Ontario. The analysis included an assessment of supply-demand conditions today as well as at the end of the initial contract term. Benjamin also developed an approach for valuing the "capacity" provided by the facility in the period after the initial contract. *[Client: Confidential (Independent Power Producer); Date: 2012; Location: Ontario, Canada]*

- **Fair market valuation of anthracite coal facility -** Fair market valuation of a waste coal plant in Pennsylvania. Utilized a discounted cash flow analysis to determine the plant's value. Reviewed operating agreements, and developed forecasts of going-forward input costs and maintenance requirements. To project revenue, forecast the energy, capacity and renewable energy credit prices in PJM. Led a site visit and interviews with key plant and owner personnel. *[Client: Confidential (Independent Power Producer); Date: 2011; Location: Pennsylvania, USA]*
- **Natural gas market analysis -** For an independent power producer considering the acquisition of a natural gas fired generation facility in Ontario, Ben and his team evaluated the current and prospective fuel (natural gas) supply environment. The analysis considered the long-term liquidity of supply at the Union Dawn Hub and alternative sources as well as transportation availability and the potential for constraints from the Union Dawn Hub to the project site. *[Client: Confidential (Independent Power Producer); Date: 2010; Location: Ontario, Canada]*
- **Valuation of combined-cycle gas turbine facility -** For an independent power producer considering the acquisition of a natural gas fired generation facility in Ontario, Ben and his team evaluated the historic performance of the facility under the Ontario Power Authority's Clean Energy Supply Contract. The analysis included developing a dispatch model that reflected the "deemed" dispatch logic in the contract. The team also provided a 30-year forecast of wholesale and consumer energy prices in Ontario under two scenarios, high and low nuclear supply. The consumer price forecast is comprised of the wholesale price forecast and a forecast of the global adjustment, which takes into account the above/below market costs of consumer funded contracts and the regulation of generation assets. *[Client: Confidential Client (Independent Power Producer); Date: 2010; Location: Ontario, Canada]*
- **Design and administration of competitive cogeneration procurement process -** Contributed to a team charged with the design and implementation of a request for proposal process for the procurement of up to 1,000 megawatts of combined heat and power projects (cogeneration). Tasks included: the designed the evaluation model that was used by the Ontario Power Authority to evaluate the individual proposed projects; and the design and review of the proposed contract. *[Client: Ontario Power Authority; Date: 2006; Location: Ontario, Canada]*
- **Power purchase agreement renegotiation support for existing natural gas facility -** Supported the renegotiation and extension of a non-utility generator contract for an existing facility in Ontario. Reviewed fuel procurement activities, and fuel price re-opener clauses within existing contract structure. Devised pricing methodology using fuel price indices and basis differential to limit exposure of counterparty to fuel procurement risk. *[Client: Ontario Electricity Financing Corporation; Date: 2006; Location: Ontario, Canada]*

Energy Efficiency

- **Independent monitor for demand response program administrator procurement -** Ben was the project manager for an engagement with the City of New Orleans. Ben and his team were engaged to act as the independent monitor for Entergy New Orleans' solicitation of a Third Party Administrator to implement and deliver conservation and demand management programs on behalf of the utility. The team provided guidance to Entergy and the City of New Orleans on the development of the request for proposals, including mandatory requirements and commercial terms. The team oversaw the bid receipt as well as the review and selection process. A final report was provided outlining the team's opinion as to the fairness of the overall process. *[Client: City of New Orleans; Date: 2010; Location: Louisiana, USA]*

- **Economic analysis of participation in New England demand response program -** Supported the development of expert witness testimony on the economics and benefits of the company's participation in the New England Day-Ahead Load Response Program. The company's participation in the program was facilitated by generation from an onsite biomass-fuelled power plant to displace internal load. *[Client: Confidential (Industrial); Date: 2009; Location: New Hampshire, USA]*
- **Evaluation of conservation and demand management supply chain capabilities -** Prepared a report on the capability of the existing supply chain in Ontario to deliver conservation and demand management results. Created a model of future conservation and demand management deliveries based on resource to output ratios developed after a detailed review of local distribution company filings before the Ontario Energy Board. The review of filings was supplemented by a telephone survey. Also identified nine potential areas where conservation and demand management programs could be leveraged, based on an analysis of overall Ontario load and coverage of existing programs. *[Client: Ontario Power Authority; Date: 2007; Location: Ontario, Canada]*
- **Energy management strategy -** Assessed the potential for energy and cost savings for a large Ontario commercial consumer. Provided a forecast of total energy supply costs and assessed the benefit of switching larger facilities to interval or time-of-use meters. Developed a road map for potential savings including the effective use of existing market mechanisms. *[Client: Confidential (Commercial); Date: 2006; Location: Ontario, Canada]*
- **Determination of avoided cost from energy efficiency measures -** Developed an estimate of avoided costs used to value conservation and demand management initiatives in Ontario. Developed models to estimate the avoided energy, capacity and transmission costs and system losses. Prepared informal testimony and presented results to staff at the Ontario Energy Board. Analysis was approved without a formal hearing and has been used by various parties to assess the value of different investment alternatives including district energy projects. *[Client: Ontario Energy Board; Date: 2006; Location: Ontario, Canada]*

Publications and Speaking Engagements

- Grunfeld, Benjamin. "Was the Investment Worth It? Looking at the Long-Term Economic Impact of Feed in Tariff Programs in Ontario and Beyond". Panel Moderator. CI Energy Group's Ontario Power Perspectives. Toronto, ON, Canada. Apr 16, 2012.
- Grunfeld, Benjamin. "Finance Innovation in Agri-Energy and Biomass". Panel Moderator. Ontario Feed-in Tariff Forum. Toronto, ON, Canada. Apr 3-4, 2012.
- Grunfeld, Benjamin. "Solar Power: How Much and When". Presenter. Third Ontario Solar Summit. Toronto, ON, Canada. Nov 8, 2011.
- Grunfeld, Benjamin. "Putting Things into Perspective, Power Sector Investment Climate in Ontario". Presenter. Ontario Energy Association 2011 Annual Conference. Niagara Falls, ON, Canada. Sep 16, 2011.
- Grunfeld, Benjamin. "Report Card on Green Energy Objectives". Presenter. Northwind Professional Institute 2011 Electricity Invitational Forum. Cambridge, ON, Canada. Jan 27, 2011.

RATE RIDER CALCULATIONS

1.0 INCREMENTAL CAPITAL MODULE (ICM) RATE RIDER

Hydro One proposes to use a volumetric rate rider to collect the incremental capital revenue requirement of $26.2 million associated with the in-service capital requirement of $644 million in 2013 described in Exhibit B, Tab 1, Schedule 1. Attachment 1 to this Exhibit shows Hydro One's calculation of the ICM volumetric rate riders by rate class.

The calculation of the ICM volumetric rate riders follows the methodology prescribed by the Board in Sheet F1.2 of the IRM3 Incremental Capital Workform. The ICM revenue requirement share to be recovered from each rate class is based on the relative share of the revenue requirement by rate class as approved by the Board in Hydro One's last Cost of Service ("COS") application EB-2009-0096. The volumetric rate rider amounts are calculated by dividing the ICM rate class revenue requirement by the kWh or kW charge determinants for each rate class approved by the Board in Hydro One's last COS application EB-2009-0096.

The proposed ICM volumetric rate riders are included in the IRM3 Model at Sheet 14 Proposed Volumetric Rate Riders.

The proposed ICM rate riders will remain in effect until new rates are implemented as part of Hydro One's next rebasing application, which is currently anticipated to be January 1, 2015.

2.0 SMART GRID RATE RIDER

Hydro One proposes to use a volumetric rate rider to collect the proposed 2013 Smart Grid OM&A expense of $19.8 million described in Exhibit C1, Tab 1, Schedule 1. Attachment 2 to this Exhibit shows Hydro One Distribution's calculation of the Smart Grid volumetric rate riders by rate class.

The calculation of the Smart Grid volumetric rate riders uses the same approach as prescribed by the Board for determining the ICM volumetric rate rider. The Smart Grid revenue requirement share to be recovered by each rate class is based on the relative share of the revenue requirement by rate class as approved by the Board in Hydro One's last COS application EB-2009-0096. The volumetric rate riders are calculated by dividing the Smart Grid rate class revenue requirement by the kWh or kW charge determinants for each rate class approved by the Board in Hydro One's last COS application EB-2009-0096.

The proposed Smart Grid volumetric rate riders are included in the IRM3 Model at Sheet 14 Proposed Volumetric Rate Riders.

3.0 SHARED TAX SAVINGS RATE RIDER

As part of the Supplemental Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors (EB-2007-0673) issued September 17, 2008, the Board determined that there would be a 50/50 sharing of the impact of currently known legislated tax changes. Hydro One Distribution has identified a shared tax savings of ($1.1) million to be refunded to customers, calculated using Sheet 5 of the Board's Shared Tax Savings Workform as described in Appendix A attached to this Exhibit.[1]

[1] The original tax savings amount of ($1.7M) used in the IRM3 Model will not be updated at this time, however, the proposed tax savings amount of ($1.1M) will be reflected in the final rate order.

Attachment 3 to this Exhibit shows Hydro One Distribution's calculation of the Shared Tax Savings volumetric rate riders by rate class required to refund the Shared Tax Savings amount noted above.

The calculation of the Shared Tax Savings volumetric rate riders uses the methodology prescribed by the Board in Sheet 6 of the Shared Tax Savings Workform. The Shared Tax Savings amounts to be refunded by rate class are based on the relative share of the revenue requirement by rate class as approved by the Board in Hydro One's last COS application EB-2009-0096. The volumetric rate riders are calculated by dividing the Shared Tax Savings rate class revenue requirement by the kWh or kW charge determinants for each rate class approved by the Board in Hydro One's last COS application EB-2009-0096.

The proposed Shared Tax Savings volumetric rate riders are included in the IRM3 Model at Sheet 14 Proposed Volumetric Rate Riders.

4.0 DEFERRAL AND VARIANCE ACCOUNT RATE RIDERS

The Report of the Board on Electricity Distributor's Deferral and Variance Account Review Initiative Report (the "EDDVAR Report") requires that during the IRM plan term, the Group 1 audited account balances be reviewed and disposed of if the preset disposition threshold of $0.001/kWh (debit or credit) is exceeded.

EB-2009-0096 included the disposition of Group 1 deferral and variance account balances as of December 31, 2009. The balance of Group 1 account balances as of December 31st, 2009 was ($31.2M). This balance was transferred to account 1595 in

May of 2010. Hydro One has used, and continues to use, the carrying charges consistent with the Board's published prescribed rates.

The account balances which are being considered for disposition under this application are the Group 1 deferral and variance account balances, including interest as of December 31, 2011. Account 1590 - Recovery of Regulatory Asset Balances includes ($9.0M) associated with the disposition of 2008 Regulatory balance and $11.4M associated with the disposition of other regulatory balances, primarily associated with RARA 2. Table 1 shows the account balances which are proposed for disposition. Details of the calculation of these amounts can be found in Attachment 4 to this Exhibit, which duplicates the contents of Sheet 9 of the IRM3 Model but expanded to include 2011 data.

Table 1
Deferral and Variance Accounts
As of December 31st, 2011

Account Description	Account No	2011 Principal Balance	2011 Carrying Charge Balance	2011 Year-End Balance
Group 1 Accounts				
LV Variance Account	1550	$6,676,832	$110,616	$6,787,448
RSVA - Wholesale Market Service Charge	1580	-$67,163,657	-$924,188	-$68,087,845
RSVA - Retail Transmission Network Charge	1584	$20,697,915	$240,324	$20,938,239
RSVA - Retail Transmission Connection Charge	1586	$9,454,348	$81,060	$9,535,408
RSVA - Power (excluding Global Adjustment)	1588			
RSVA - Power - Sub-Account - Global Adjustment	1588	-$8,739,863	-$156,105	-$8,895,968
Recovery of Regulatory Asset Balances[2]	1590	-$5,234,904	$7,696,367	$2,461,463
Disposition & Recovery of Regulatory Balance	1595	$69,385	-$277,348	-$207,963
Total Group 1 Account Balances		**-$44,239,943**	**$6,770,727**	**-$37,469,216**

[2] Account 1590 - Recovery of Regulatory Asset Balances includes ($8,983,518) associated with the disposition of 2008 Regulatory balance and $11,444,981 associated with the disposition of other regulatory balances, primarily associated with RARA 2.

The disposition threshold test for Group 1 Accounts was performed using the 2010 OEB approved volume forecast of 36,168,638,710 kWh as per Exhibit G2-1-1, Attachment 1, page 19 from Hydro One Distribution's last COS application EB-2009-0096. The Group 1 account threshold test, based on a proposed total claim amount of $37,469,216 million and the approved volume forecast, determined an amount of $0.00104 per kWh which is above the ceiling rate of $0.001 per kWh established by the Board. The Deferral and Variance Account disposition threshold calculations have been performed as part of Sheet 10 in the IRM3 Model, which is included in the Model outputs provided in Exhibit E2, Tab 1, Schedule 1.

Hydro One Distribution is proposing to dispose of the Group 1 deferral accounts over a two year period for the years 2013 and 2014. Hydro One recognizes that the "EDDVAR Report" stipulates that Group 1 deferral accounts be disposed over a one-year period. Hydro One also notes that a distributor can propose a different period in order to mitigate rate impacts. Hydro One recognizes the important of avoiding intergenerational inequity. However, Hydro One Distribution is proposing a disposition period of two years in order to avoid large rate fluctuations in rates over the 2013 to 2014 period. Hydro One Distribution has revised the allocator used to split the balance in USofA 1580 (RSVA-Wholesale Market Service Charge) from "kWh" to "kWh excluding Wholesale Market Participants" (WMP). The use of kWh excluding WMP is consistent with how the Board has previously approved the splitting of the balance in account 1580 between rate classes as part of Hydro One's previous COS applications EB-2009-0096 (2010/2011), EB-2007-0681 (2007/2008) and EB-2005-0378 (2006). The exclusion of WMPs from the disposition of account 1580 for Hydro One Distribution recognizes the fact that about 36% of the kWh load attributed to the ST customer class is associated with WMPs. Given that customers who are WMPs do not contribute to the variance in account 1580, it is appropriate they not participate in the disposition of this account.

Hydro One Distribution has revised the charge determinant used to calculate the rate rider for USofA 1588 (Global Adjustment) from “Billed kWh or Estimated kW for Non-RPP customers” to “Billed kWh for Non-RPP customers”. This proposed change is consistent with how the balance amount for USofA 1588 is allocated between rate classes. The proposed change is also consistent with the approach used by Hydro One Distribution, and approved by the Board, to establish the Global Adjustment rate rider under COS application EB-2009-0096. The proposed change recognizes that Global Adjustment costs are related to the electricity commodity costs for non-RPP customers and are driven by kWh consumption of non-RPP customers.

Hydro One Distribution has revised the allocator used to split the residual balances tracked in USofA account 1595 (Disposition and Recovery of Regulatory Balances (2008) and Disposition and Recovery of Regulatory Balances (2009)). The proposed allocator of the residual balance between rate classes is the share of revenue recovery by rate class at the time the original riders were established for disposing of the variance account balances. This treatment is consistent with the intent of the note associated with the splitting of these account balances per Sheet 10 of the IRM3 model, which states “Residual Account balance to be allocated to rate classes in proportion to the recovery share as established when rate riders were implemented”.

The recovery shares for the USofA 1595 - 2009 variance account residual balance is based on the amounts shown in row 25 of Exhibit 2.2 provided in the 2010 Draft Rate Order under COS application EB-2009-0096. The recovery shares for the USofA 1595 - 2008 variance account residual balance is based on the amounts shown in row 26 of Exhibit 2.0 provided in the 2008 Draft Rate Order under COS application EB-2007-0681.

The balance tracked in USofA account 1590 (Recovery of Regulatory Asset Balances) is largely associated with the residual variance account balance for disposition of RARA 2 approved under EB-2005-0378. The disposition of the USofA 1590 residual balances follows the same recovery share approach used for disposing of the USofA 1595 balances. However, because the original disposition of RARA 2 was on the basis of the old rate class structure that existed in 2006, prior to the harmonization of Hydro One's rate classes, there is not a direct link to the recovery share under the currently approved rate classes. The same situation existed when the residual variance account balance associated with RARA 1 was disposed of as part of Hydro One's 2008 COS application EB-2007-0681. In that proceeding the Board approved a process for the disposition of RARA 1 that translated the amounts collected under the old rate class structure to equivalent amounts under the new currently approved rate structure. Hydro One has used this previously approved methodology for translating the recovery share amounts between old and new rate classes to establish the recovery share for RARA 2.

Ontario Energy Board

2012 IRM 3 Tax Savings Workform

Hydro One Networks Inc

This worksheet calculates the tax sharing amount.

Step 1: Press the Update Button (this will clear all input cells and reveal your latest cost of service re-basing year).
Step 2: In the green input cells below, please enter the information related to the last Cost of Service Filing.

Summary - Sharing of Tax Change Forecast Amounts

For the 2008 year, enter any Tax Credits from the Cost of Service Tax Calculation (Positive #)	$ 1,400,000	
1. Tax Related Amounts Forecast from Capital Tax Rate Changes	**2011**	**2013**
Taxable Capital		$ -
Deduction from taxable capital up to $15,000,000		$ -
Net Taxable Capital	$ -	$ -
Rate	0.225%	0.225%
Ontario Capital Tax (Deductible, not grossed-up)	**$ -**	**$ -**
2. Tax Related Amounts Forecast from Income Tax Rate Changes	**2011**	**2013**
Regulatory Taxable Income	$ 126,100,000	$ 126,100,000
Corporate Tax Rate	28.30%	26.50%
Tax Impact	$ 34,200,000	$ 32,016,500
Tax Amount	**$ 34,200,000**	**$ 32,016,500**
Tax Related Amounts Forecast from Capital Tax Rate Changes	$ -	$ -
Tax Related Amounts Forecast from Income Tax Rate Changes	$ 34,200,000	$ 32,016,500
Total Tax Related Amounts	**$ 34,200,000**	**$ 32,016,500**
Incremental Tax Savings		**-$ 2,183,500**
Sharing of Tax Savings (50%)		**-$ 1,091,750**

PROPOSED RATE SCHEDULES

For all rate schedules attached to this Exhibit the note associated with Volumetric Rate Rider # 10 – Incremental Capital Costs should read “(expires December 31, 2014 or when new 2015 rates come into effect)”.

PROPOSED RATE SCHEDULES BASED ON DENSITY STUDY ADJUSTED RATES

The rate schedules in this Exhibit replace the equivalent non-Density Study Adjusted rate schedules provided in Exhibit E2, Tab 2, Schedule 2.

For all rate schedules attached to this Exhibit the note associated with Volumetric Rate Rider # 10 – Incremental Capital Costs should read "(expires December 31, 2014 or when new 2015 rates come into effect)".

HYDRO ONE NETWORKS INC.

RATES FOR RETAIL DISTRIBUTION SERVICE

Effective Date: January 1, 2013

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Residential – Urban [UR]

Monthly Rates and Charges - Electricity Component		
Rate Rider for 2012 Global Adjustment Sub-Account Disposition – Non – RPP Customers (expires December 31, 2014)	$ / kWh	(0.0005)
Monthly Rates and Charges - Delivery Component		
Service Charge (includes Smart Meter Funding Adder - $3.92)	$	16.48
Distribution Volumetric Rate	$ / kWh	0.02524
Volumetric Rate Rider #9 - Deferral/Variance Account Disposition 2012 (expires December 31, 2014)	$ / kWh	(0.00093)
Volumetric Rate Rider #10 - Incremental Capital Costs (expires December 31, 2013)	$ / kWh	0.0011
Volumetric Rate Rider #11 - Smart Grid Costs (expires December 31, 2013)	$ / kWh	0.0008
Volumetric Rate Rider #12 - Shared Tax Savings (expires December 31, 2013)	$ / kWh	(0.0001)
Retail Transmission Rate - Network Service Rate (4)	$ / kWh	0.00696
Retail Transmission Rate - Line and Transformation Connection Service Rate (5)	$ / kWh	0.00500
Monthly Rates and Charges - Regulatory Component		
Wholesale Market Service Rate (7) (13)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (7) (13)	$ / kWh	0.0011
Standard Supply Service - Administration Charge (if applicable)	$	0.25

HYDRO ONE NETWORKS INC.

RATES FOR RETAIL DISTRIBUTION SERVICE

Effective Date: January 1, 2013

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Residential – Low Density [R2]

Monthly Rates and Charges - Electricity Component		
Rate Rider for 2012 Global Adjustment Sub-Account Disposition – Non – RPP Customers (expires December 31, 2014)	$ / kWh	(0.0005)
Monthly Rates and Charges - Delivery Component		
Service Charge* (includes Smart Meter Funding Adder - $3.92)	$	61.50
Distribution Volumetric Rate	$ / kWh	0.03723
Volumetric Rate Rider #9 - Deferral/Variance Account Disposition 2012 (expires December 31, 2014)	$ / kWh	(0.00085)
Volumetric Rate Rider #10 - Incremental Capital Costs (expires December 31, 2013)	$ / kWh	0.0019
Volumetric Rate Rider #11 - Smart Grid Costs (expires December 31, 2013)	$ / kWh	0.0014
Volumetric Rate Rider #12 - Shared Tax Savings (expires December 31, 2013)	$ / kWh	(0.0001)
Retail Transmission Rate - Network Service Rate (4)	$ / kWh	0.00690
Retail Transmission Rate - Line and Transformation Connection Service Rate (5)	$ / kWh	0.00480
Monthly Rates and Charges - Regulatory Component		
Wholesale Market Service Rate (7) (13)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (7) (13)	$ / kWh	0.0011
Standard Supply Service - Administration Charge (if applicable)	$	0.25

* Under the Ontario Energy Board Act, 1998 and associated regulations, every qualifying year-round customer with a principal residence is eligible to receive Rural or Remote Rate Protection (RRRP). The service charge shown for eligible R2 customers will be reduced by the applicable RRRP credit, currently at $28.50.

HYDRO ONE NETWORKS INC.

RATES FOR RETAIL DISTRIBUTION SERVICE

Effective Date: January 1, 2013

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Seasonal Residential – Seasonal

Monthly Rates and Charges - Electricity Component		
Rate Rider for 2012 Global Adjustment Sub-Account Disposition – Non – RPP Customers (expires December 31, 2014)	$ / kWh	(0.0005)
Monthly Rates and Charges - Delivery Component		
Service Charge (includes Smart Meter Funding Adder - $3.92)	$	23.38
Distribution Volumetric Rate	$ / kWh	0.08101
Volumetric Rate Rider #9 - Deferral/Variance Account Disposition 2012 (expires December 31, 2014)	$ / kWh	(0.00065)
Volumetric Rate Rider #10 - Incremental Capital Costs (expires December 31, 2013)	$ / kWh	0.0030
Volumetric Rate Rider #11 - Smart Grid Costs (expires December 31, 2013)	$ / kWh	0.0023
Volumetric Rate Rider #12 - Shared Tax Savings (expires December 31, 2013)	$ / kWh	(0.0002)
Retail Transmission Rate - Network Service Rate (4)	$ / kWh	0.00652
Retail Transmission Rate - Line and Transformation Connection Service Rate (5)	$ / kWh	0.00470
Monthly Rates and Charges - Regulatory Component		
Wholesale Market Service Rate (7) (13)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (7) (13)	$ / kWh	0.0011
Standard Supply Service - Administration Charge (if applicable)	$	0.25

HYDRO ONE NETWORKS INC.

RATES FOR RETAIL DISTRIBUTION SERVICE

Effective Date: January 1, 2013

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Urban General Service Energy Billed (less than 50 kW) [UGe]

Monthly Rates and Charges - Electricity Component		
Rate Rider for 2012 Global Adjustment Sub-Account Disposition – Non – RPP Customers (expires December 31, 2014)	$ / kWh	(0.0005)
Monthly Rates and Charges - Delivery Component		
Service Charge (includes Smart Meter Funding Adder - $3.92)	$	13.99
Distribution Volumetric Rate	$ / kWh	0.01663
Volumetric Rate Rider #9 - Deferral/Variance Account Disposition 2012 (expires December 31, 2014)	$ / kWh	(0.00106)
Volumetric Rate Rider #10 - Incremental Capital Costs (expires December 31, 2013)	$ / kWh	0.0006
Volumetric Rate Rider #11 - Smart Grid Costs (expires December 31, 2013)	$ / kWh	0.0005
Retail Transmission Rate - Network Service Rate (4)	$ / kWh	0.00535
Retail Transmission Rate - Line and Transformation Connection Service Rate (5)	$ / kWh	0.00366
Monthly Rates and Charges - Regulatory Component		
Wholesale Market Service Rate (7) (13)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (7) (13)	$ / kWh	0.0011
Standard Supply Service - Administration Charge (if applicable)	$	0.25

HYDRO ONE NETWORKS INC.

RATES FOR RETAIL DISTRIBUTION SERVICE

Effective Date: January 1, 2013

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

General Service Demand Billed (50 kW and above) [GSd]

Monthly Rates and Charges - Electricity Component		
Rate Rider for 2012 Global Adjustment Sub-Account Disposition – Non – RPP Customers (expires December 31, 2014)	$ / kWh	3.572
Monthly Rates and Charges - Delivery Component		
Service Charge (includes Smart Meter Funding Adder - $3.92)	$	54.29
Distribution Volumetric Rate	$ / kW	11.079
Volumetric Rate Rider #9 - Deferral/Variance Account Disposition 2012 (expires December 31, 2014)	$ / kW	(0.00870)
Volumetric Rate Rider #10 - Incremental Capital Costs (expires December 31, 2013)	$ / kW	0.0206
Volumetric Rate Rider #11 - Smart Grid Costs (expires December 31, 2013)	$ / kW	0.0156
Volumetric Rate Rider #12 - Shared Tax Savings (expires December 31, 2013)	$ / kW	(0.0163)
Retail Transmission Rate - Network Service Rate (4)	$ / kW	3.18
Retail Transmission Rate - Line and Transformation Connection Service Rate (5)	$ / kW	0.70
Monthly Rates and Charges - Regulatory Component		
Wholesale Market Service Rate (7) (13)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (7) (13)	$ / kWh	0.0011
Standard Supply Service - Administration Charge (if applicable)	$	0.25

HYDRO ONE NETWORKS INC.

RATES FOR RETAIL DISTRIBUTION SERVICE

Effective Date: January 1, 2013

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Urban General Service Demand Billed (50 kW and above) [UGd]

Monthly Rates and Charges - Electricity Component		
Rate Rider for 2012 Global Adjustment Sub-Account Disposition – Non – RPP Customers (expires December 31, 2014)	$ / kWh	1.63
Monthly Rates and Charges - Delivery Component		
Service Charge (includes Smart Meter Funding Adder - $3.92)	$	32.27
Distribution Volumetric Rate	$ / kW	6.900
Volumetric Rate Rider #9 - Deferral/Variance Account Disposition 2012 (expires December 31, 2014)	$ / kW	(0.35601)
Volumetric Rate Rider #10 - Incremental Capital Costs (expires December 31, 2013)	$ / kW	0.1907
Volumetric Rate Rider #11 - Smart Grid Costs (expires December 31, 2013)	$ / kW	0.1441
Volumetric Rate Rider #12 - Shared Tax Savings (expires December 31, 2013)	$ / kW	(0.0125)
Retail Transmission Rate - Network Service Rate (4)	$ / kW	1.75
Retail Transmission Rate - Line and Transformation Connection Service Rate (5)	$ / kW	1.19
Monthly Rates and Charges - Regulatory Component		
Wholesale Market Service Rate (7) (13)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (7) (13)	$ / kWh	0.0011
Standard Supply Service - Administration Charge (if applicable)	$	0.25

HYDRO ONE NETWORKS INC.

RATES FOR RETAIL DISTRIBUTION SERVICE

Effective Date: January 1, 2013

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Street Lights

Monthly Rates and Charges - Electricity Component		
Rate Rider for 2012 Global Adjustment Sub-Account Disposition – Non – RPP Customers (expires December 31, 2014)	$ / kWh	(0.0005)
Monthly Rates and Charges - Delivery Component		
Service Charge	$	1.10
Distribution Volumetric Rate	$ / kWh	0.05502
Volumetric Rate Rider #9 - Deferral/Variance Account Disposition 2012 (expires December 31, 2014)	$ / kWh	(0.00102)
Volumetric Rate Rider #10 - Incremental Capital Costs (expires December 31, 2013)	$ / kWh	0.0012
Volumetric Rate Rider #11 - Smart Grid Costs (expires December 31, 2013)	$ / kWh	0.0009
Volumetric Rate Rider #12 - Shared Tax Savings (expires December 31, 2013)	$ / kWh	(0.0001)
Retail Transmission Rate - Network Service Rate (4)	$ / kWh	0.00435
Retail Transmission Rate - Line and Transformation Connection Service Rate (5)	$ / kWh	0.00303
Monthly Rates and Charges - Regulatory Component		
Wholesale Market Service Rate (7) (13)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (7) (13)	$ / kWh	0.0011
Standard Supply Service - Administration Charge (if applicable)	$	0.25

HYDRO ONE NETWORKS INC.

RATES FOR RETAIL DISTRIBUTION SERVICE

Effective Date: January 1, 2013

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Sentinel Lights

Monthly Rates and Charges - Electricity Component		
Rate Rider for 2012 Global Adjustment Sub-Account Disposition – Non – RPP Customers (expires December 31, 2014)	$ / kWh	(0.0005)
Monthly Rates and Charges - Delivery Component		
Service Charge	$	1.10
Distribution Volumetric Rate	$ / kWh	0.07355
Volumetric Rate Rider #9 - Deferral/Variance Account Disposition 2012 (expires December 31, 2014)	$ / kWh	(0.00100)
Volumetric Rate Rider #10 - Incremental Capital Costs (expires December 31, 2013)	$ / kWh	0.0021
Volumetric Rate Rider #11 - Smart Grid Costs (expires December 31, 2013)	$ / kWh	0.0016
Volumetric Rate Rider #12 - Shared Tax Savings (expires December 31, 2013)	$ / kWh	(0.0001)
Retail Transmission Rate - Network Service Rate (4)	$ / kWh	0.00435
Retail Transmission Rate - Line and Transformation Connection Service Rate (5)	$ / kWh	0.00303
Monthly Rates and Charges - Regulatory Component		
Wholesale Market Service Rate (7) (13)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (7) (13)	$ / kWh	0.0011
Standard Supply Service - Administration Charge (if applicable)	$	0.25

MicroFIT Generator

Service Charge	$	5.25