DENSITY STUDY

Hydro One has completed a study of the relationship between customer density and cost allocation to satisfy the direction from the Board in their Decision on the 2010/11 rate application EB-2009-0096. The objectives of the study were to: i) evaluate the relationship between customer density and distribution service costs; ii) assess whether the existing density based rate classes and density weighting factors appropriately reflect this relationship; and, iii) consider the possibility of establishing alternate customer class definitions.

Hydro One met with stakeholders on September 8, 2010 to get their input on how to proceed in responding to the Board's direction on this issue. The notes of meeting from that stakeholder session are provided as Appendix A to Exhibit A, Tab 4, Schedule 1. Among the feedback received from stakeholders was that it would be desirable to apply more than one method or model to complete the study in order to increase the accuracy and confidence in the results. A number of stakeholders also suggested the importance of first establishing the relationship between density and cost before proceeding to establish what that might mean for existing density-based customer classes.

In response to the feedback received at the first stakeholder session, Hydro One engaged London Economics International (LEI) and PowerNex Associates (PNXA) to develop a methodology for completing a study that satisfied the Board's direction, while being mindful of the need to take into consideration timing, feasibility and cost in completing the study. LEI/PNXA developed and tested a proposed methodology for completing the study as part of a staged approach to engaging their services. The proposed methodology consisted of using two approaches to explore the relationship between density and cost-to-serve: an econometric analysis and a direct-cost assignment analysis. A second stakeholder session was held on March 22, 2011 to solicit stakeholder input on the proposed study methodology. The notes of meeting from this second stakeholder session are provided as Appendix B to Exhibit A, Tab 4, Schedule 1. Stakeholders were supportive of the proposed methodology.

On October 19, 2011, Hydro One held a stakeholder session which provided a summary of the implementation of the study methodology and reviewed the results and findings of the Density Study. The notes of meeting from this third stakeholder session are provided as Appendix D to Exhibit A, Tab 4, Schedule 1.

A final stakeholder session was held on June 5, 2012 to review options for implementing the findings of the Density Study as part of the current 2013 IRM application. The notes of meeting from this fourth stakeholder session are provided as Appendix E to Exhibit A, Tab 4, Schedule 1.

The Density Study report prepared by LEI/PNXA that Hydro One believes satisfies the Direction from the Board in their Decision under proceeding EB-2009-0096 is provided as Attachment 1 to this Exhibit.

The Density Study concludes that the results of both the econometric and direct cost assignment approaches used in the study demonstrate there is a statistically significant relationship between customer density and distribution service costs. Both analyses clearly show that Hydro One's distribution service costs decrease as customer density increases. The ratio between the cost per customer of serving high density (HD), medium density (MD) and low density (LD) areas are shown in Figures 27 and 28 of the Density Study and summarized in Table 1.

Table 1

Density Study Findings on Relative Costs of Serving Different Density Areas

	HD	MD	LD
Ratio of OM&A[1] and Fixed Asset Costs	1.0	1.9	4.8
Ratio of Total Costs	1.0	1.7	3.9

[1] Excludes customer-related costs (except meter reading and customer premises work) and Administrative and General costs.

The Density Study results confirm the appropriateness of having density-based rate classes. Hydro One currently uses density weighting factors within the Board's cost allocation model (CA Model) to allocate overhead line and transformer costs between its density-based rate classes. The density weighting factors currently approved by the Board allocate costs among the Residential, General Service Energy and General Service Demand classes separately. The cost per customer account as determined from the results of the 2010 CA Model submitted in Hydro One Distribution's last Cost of Service ("COS") application EB-2009-0096 are calculated in Table 2.

Table 2.

Cost Per Customer from the 2010 CA Model

	UR	R1	R2	Seasonal	UGe	GSe	UGd	GSd
# of Customer Accounts	140,540	412,455	367,107	156,901	10,577	98,776	1,130	7,361
Total Cost ($M)	$59.0	$273.4	$431.7	$96.0	$8.7	$121.5	$12.6	$128.8
Total Cost per Customer	$420	$663	$1,176	$612	$818	$1,230	$11,128	$17,491
Ratio of Total Cost per Cust relative to Urban	1.0	1.6	2.8	1.5	1.0	1.5	1.0	1.6
OM&A[1] and Fixed Asset (FA) Cost ($M)	$44.7	$223.0	$367.4	$84.0	$6.7	$99.9	$11.1	$115.4
OM&A and FA Cost per Customer	$318	$541	$1,001	$535	$633	$$1,011	$9,826	$15,679
Ratio of OM&A and FA Cost per Cust relative to Urban	1.0	1.7	3.1	1.7	1.0	1.6	1.0	1.6

[1] Total costs excluding customer related costs (except meter reading and customer premises work) and Administrative & General costs

A comparison of the relative cost ratios from Tables 1 and 2 clearly shows that the costs allocated by the 2010 CA Model understate the relative cost of serving density-based rate classes as determined by the Density Study.

Hydro One proposes to revise the allocation of costs to its density-based rate classes by adjusting the ratio between the cost per customer allocated by the 2010 CA Model to more closely align with the Density Study results.

The target cost ratio for the General Service Energy (GSe) rate class relative to the Urban General Service Energy (UGe) rate class has been set to a value between that of the medium and low density areas as determined by the Density Study. The proposed target cost ratio for the GSe class is based on consideration of the actual relative density of Hydro One's GSe customers as compared to UGe customers.[1] The target cost ratio for the General Service Demand (GSd) rate class relative to the Urban General Service Demand (UGd) rate class has been set at the value for the medium density area as determined by the Density Study.[2]

The target ratio for the Seasonal class has been set equal to that of the R1 class, consistent with the CA Model output which shows the total cost per customer for these two rate classes is about the same despite the existing weighting factors for the Seasonal classes being between that of the medium and low rate classes, as suggested by the findings of the Density Study.

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[1] Based on an assessment of the # of customers per km of line for all Hydro One rate classes, the density of the GSe rate class is 5.4 times that of UGe rate class, which compares to a relative density of 3.9 times for the R1 residential rate class and 10.0 times for the R2 residential rate class, as compared to the urban (UR) residential rate class.

[2] Based on an assessment of the # of customers per km of line for all Hydro One rate classes, Hydro One's GSd customers have about the same relative density when compared to UGd customers as the medium residential (R1) rate class has relative to the urban residential (UR) rate class.

Two options were considered for adjusting the costs per customer determined by the 2010 CA Model to match the cost ratios specified by the Density Study. Table 3 shows the impacts of making the Density Study adjustment (DSA) based on the total costs allocated by the CA Model, while Table 4 shows the impacts of adjusting only the OM&A (excluding customer related and Administrative & General cost) and Fixed Asset costs.

Table 3.

Density Study-Adjusted (DSA) CA Model Results Based on Total Costs

	UR	R1	R2	Seasonal	UGe	GSe	UGd	GSd
Target Cost per Customer Ratio	1.0	1.7	3.9	1.7	1.0	2.2	1.0	1.7
DSA Total Cost per Customer	$339	$576	$1,320	$576	$571	$1,257	$10,359	$17,609
DSA Total Cost ($M)	$47.6	$237.4	$484.7	$90.3	$6.0	$124.1	$11.7	$129.6
Revenue Collected ($M)	$64.5	$253.8	$450.0	$98.6	$10.4	$130.1	$15.7	$113.4
DSA Revenue to Cost (R/C) Ratio	1.36	1.07	0.93	1.09	1.73	1.06	1.34	0.87
2010 R/C Ratio per CA Model	1.09	0.93	1.04	1.03	1.21	1.07	1.25	0.88

Table 4

Density Study-Adjusted (DSA) CA Model results based on OM&A and Fixed Asset (FA) Costs

	UR	R1	R2	Seasonal	UGe	GSe	UGd	GSd
Target Cost per Customer Ratio	1.0	1.9	4.8	1.9	1.0	2.6	1.0	1.9
DSA OM&A and FA Cost per Customer	$241	$458	$1,157	$458	$399	$1,037	$8,370	$15,903
DSA OM&A and FA Costs ($M)	$33.9	$188.8	$424.6	$71.8	$4.2	$102.4	$9.5	$117.1
DSA Total Cost ($M)	$48.1	$239.2	$488.8	$83.9	$6.2	$124.0	$10.9	$130.4
Revenue Collected ($M)	$64.5	$253.8	$450.0	$98.6	$10.4	$130.1	$15.7	$113.4
DSA Revenue to Cost (R/C) Ratio	1.34	1.06	0.92	1.17	1.69	1.05	1.44	0.87
2010 R/C Ratio per CA Model	1.09	0.93	1.04	1.03	1.21	1.07	1.25	0.88

Hydro One proposes to adopt the second approach shown in Table 4. This approach was supported by stakeholders and provides better alignment between the costs specifically addressed by the Density Study and the CA Model costs. This approach also ensures that the allocation of the customer related OM&A and A&G costs, which are largely independent of density, will remain as allocated by the CA Model.

As shown in Table 4, the density study-adjusted revenue-to-cost (R/C) ratio for the urban density rate classes and Seasonal rate class are well above the R/C ratios that were approved by the Board in the last COS application and are outside the Board approved R/C ratio ranges for these rate classes. This indicates that under current rates, the amount of revenue collected from the urban Residential and General Service rate classes, as well as the Seasonal rate class, is in excess of what the Density Study results demonstrate to be appropriate. Hydro One believes this disparity needs to be addressed as part of its 2013 IRM application.

Hydro One considered two options for addressing this disparity. Option 1 is to lower the revenues to be collected from those rate classes that are outside the Board approved R/C ratio range to the Board-approved R/C ratio limit for those rate classes. Option 2 would be to lower the R/C ratios for those rate classes to the R/C ratios previously approved by the Board as part of Hydro One's last COS application, EB-2009-0096.

Table 5

Revenue Adjustments Required to Bring R/C Ratios to Limits of Board Approved Ranges

(All $ in millions)	UR	R1	R2	Seasonal	UGe	GSe	UGd	GSd	Street Lights	Sentinel Lights
2010 CA Model Revenues	$64.5	$253.8	$450.0	$98.6	$10.4	$130.1	$15.7	$113.4	$6.5	$5.1
DSA Total Cost	$48.1	$239.2	$488.8	$83.9	$6.2	$124.0	$10.9	$130.4	$9.5	$7.6
Target R/C Ratio	1.15	1.06	0.94	1.15	1.20	1.05	1.20	0.91	0.71	0.7
Target Revenue to be recovered	$55.3	$253.8	$461.3	$96.5	$7.4	$130.1	$13.1	$118.5	$6.7	$5.3
Revenue Adjustment Required to achieve Target R/C	- $9.2	None	+ $11.3	- $2.1	- $3.0	None	-$2.6	$5.1	$0.3	$0.2
Average Rate Impacts	***-14.3%***	***None***	***+2.5%***	***-2.1%***	***-29.1%***	***None***	***-16.4%***	***+4.5%***	***+4.5%***	***+4.5%***

Table 6

Revenue Adjustments Required to Bring R/C Ratios to Previously Approved R/C Levels

(All $ in millions)	UR	R1	R2	Seasonal	Urban GSe	GSe	Urban GSd	GSd	Sentinel Lights	Street Lights
2010 CA Model Revenues	$64.5	$253.8	$450.0	$98.6	$10.4	$130.1	$15.7	$113.4	$6.5	$5.1
DSA Total Cost	$48.1	$239.2	$488.8	$83.9	$6.2	$124.0	$10.9	$130.4	$9.5	$7.6
Target R/C Ratio	1.09	1.06	0.97	1.03	1.21	1.05	1.25	0.91	0.72	0.70
Target Revenue to be recovered	$52.6	$253.8	$473.0	$86.1	$7.4	$130.1	$13.6	$119.2	$6.8	$5.3
Revenue Adjustment Required to achieve Target R/C	- $11.9	None	+ $23.0	- $12.5	- $3.0	None	-$2.1	$5.8	$0.3	$0.3
Average Rate Impacts	***-18.4%***	***None***	***+5.1%***	***-12.6%***	***-28.7%***	***None***	***-13.1%***	***+5.1%***	***+5.1%***	***+5.1%***

The detailed calculations associated with both options for adjusting the 2010 CA Model results in response to the Density Study findings are provided in Attachment 2 to this Exhibit, and summarized in Tables 5 and 6. Table 5 shows the impacts of implementing Option 1 and Table 6 shows the impact of implementing Option 2. For both options, the revenue to be shifted from the affected rate classes in order to bring the R/C ratios for those rate classes to the target values will be allocated to those rate classes whose R/C ratio is below 1 (i.e. the Low Density (R2) residential rate class, the GSd rate class, and the Sentinel and Street Lighting rate classes).

Option 2 results in rates for the residential rate classes that more closely reflect the cost of serving those classes, since the R/C ratios are closer to 1, and it would address the existing rate disparity between the classes more quickly than Option 1. However, Option 2 also results in more significant rate impacts to the affected rate classes.

Hydro One believes that implementation of the Density Study findings represents an improvement to the allocation of costs to its customer classes. Such an improvement to the allocation of costs would merit moving beyond the Board-approved limit for the R/C ratio of its density based classes to get closer to a R/C value of 1.0. However, as noted by a number of participants at the June 5 stakeholder session, adopting a staged approach to the implementation of the Density Study findings will help mitigate the rate impact on customers. As such, Hydro One proposes moving to the Board-approved limits for the R/C ratios (Option 1) as part of its 2013 IRM application.

In adopting Option 1, Hydro One proposes to re-allocate the revenue to be shifted from the urban General Service classes to both the General Service Demand and Lighting classes in a manner that results in equivalent rate impacts to those classes. Hydro One further proposes that the revenue to be shifted from the Urban and Seasonal residential rate classes be allocated to the Low Density (R2) rate class. Hydro One does not propose that any revenue from the Urban Residential and Seasonal rate classes be shifted to the General Service Demand and Lighting classes given that the rate impact of 4.5% experienced by those classes is already above the 2.5% rate impact experienced by the R2 rate class.

As detailed in Attachment 3 to this Exhibit, and summarized in Table 7, Hydro One has determined the impact on current rates for the affected rate classes of making the proposed revenue adjustments described above, and subsequently updating the rates for the approved IRM increase of 0.88%.

Table 7

Proposed 2013 Density Study Adjusted IRM Rates

Rate Class	Current Rates			Density Study Adjusted IRM Rates		
	Fixed Charge	Variable Charge		Fixed Charge	Variable Charge	
	$/month	$/kWh	$/kW	$/month	$/kWh	$/kW
UR	14.52	0.02918	-	12.56	0.02524	-
R1	19.72	0.03317	-	19.89	0.03346	-
R2	55.69	0.03600	-	57.58	0.03723	-
Seasonal	19.71	0.08205	-	19.46	0.08101	-
GSe	35.49	0.03938	-	35.80	0.03973	-
GSd	47.72	-	10.499	50.37	-	11.079
UGe	14.08	0.02325	-	10.07	0.01663	-
UGd	33.62	-	8.173	28.35	-	6.900
St Light	1.05	0.05219	-	1.10	0.05502	-
Sen Light	1.05	0.06972	-	1.10	0.07355	-

Proposed Rate Schedules based on the Density Study adjusted IRM rates are provided in Exhibit E2, Tab 2, Schedule 3. Updated total monthly bill impacts based on the Density Study adjusted IRM rates and including all proposed rate riders and adders, are provided in Exhibit E2, Tab 3, Schedule 2 for each rate affected rate class. A comparison of the IRM Total Bill impacts (as per per Exhibit Exhibit E3, Tab 3, Schedule 1) versus Density Study Adjusted (DSA) IRM Total Bill Impacts are summarized in Table 8.

Table 8

Comparison of Proposed 2013 Density Study Adjusted IRM Total Bill Impacts

Customer Type		Monthly Consumption (kWh, kW)	Current Total Monthly Bill ($)	Proposed Total Monthly Bill ($)	Change ($)	Change (%)
Residential – High Density (UR)	IRM	800 kWh	132.26	134.75	2.49	1.88%
	DSA IRM	800 kWh	132.26	129.22	-3.05	-2.30%
Residential – Low Density (R2)	IRM	800 kWh	151.74	155.79	4.05	2.67%
	DSA IRM	800 kWh	151.74	157.96	6.22	4.10%
Residential - Seasonal	IRM	500 kWh	116.61	120.24	3.63	3.11%
	DSA IRM	500 kWh	116.61	118.92	2.30	1.98%
Urban GSe	IRM	2,000 kWh	296.95	300.27	3.32	1.12%
	DSA IRM	2,000 kWh	296.95	282.18	-14.77	-4.97%
GSe	IRM	2,000 kWh	351.09	357.28	6.19	1.76%
	DSA IRM	2,000 kWh	351.09	357.28	6.19	1.76%
Urban GSd	IRM	36,000 kWh, 117 kW	5,241.08	5,296.43	55.35	1.06%
	DSA IRM	36,000 kWh, 117 kW	5,241.08	5,130.74	-110.34	-2.11%
GSd	IRM	36,000 kWh, 117 kW	5,519.56	5,592.20	72.63	1.32%
	DSA IRM	36,000 kWh, 117 kW	5,519.56	5,652.48	132.92	2.41%
Street Lights	IRM	1,320 kWh	241.11	244.79	3.68	1.53%
	DSA IRM	1,320 kWh	241.11	248.30	7.19	2.98%
Sentinel Lights	IRM	62 kWh	11.76	12.04	0.28	2.37%
	DSA IRM	62 kWh	11.76	12.29	0.52	4.45%

At this time Hydro One is not proposing any changes to the number, or delineation, of its existing rate classes in response to the Density Study findings. The Density Study indicates that three density-based residential classes and two density-based general service classes appear reasonable and based on the results of the study, there does not appear to be an immediate or pressing need to change the number of existing density-based rate classes.

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

LONDON ECONOMICS

390 Bay Street, Suite 1101
Toronto, Ontario M5H 2Y2
T: (416) 643-6610
F: (416) 643-6611
www.londoneconomics.com

27 Ashgrove Place
Toronto, Ontario M3B 2Y9
T: (416) 487- 4175
F: (416) 487- 3706
www.pnxa.com

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.

I. Evaluation of the Relationship between Customer Density and Distribution Service Costs

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

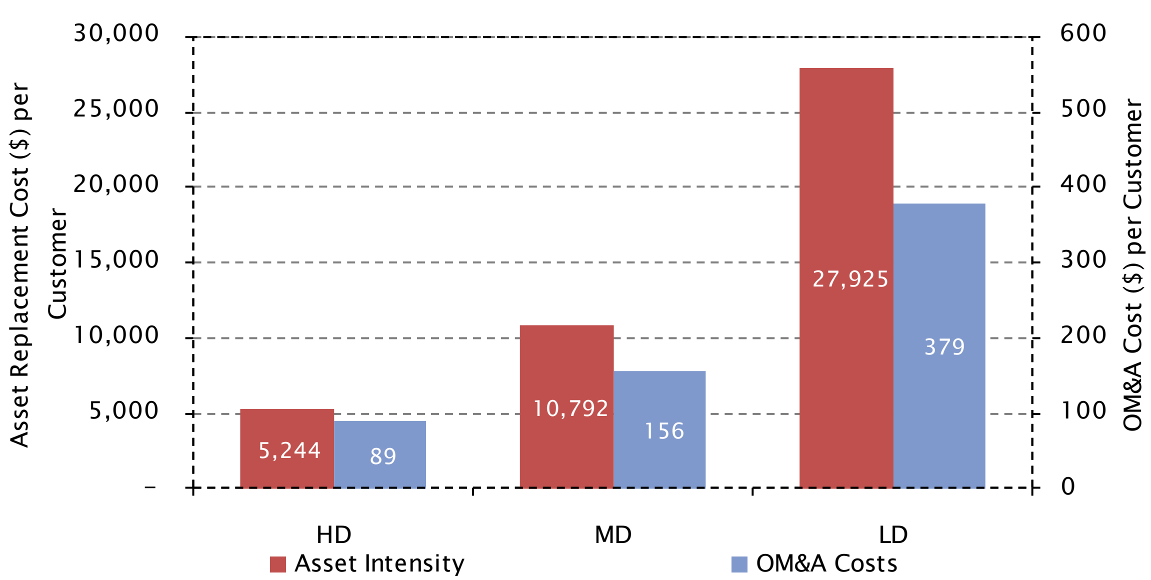
Costs Modeled in Econometric Model	Density Measure	Estimated Coefficient	95 Percent Confidence Interval	
			Low	High
OM&A	$CD_{ciircuit-km}$	-0.299	-0.368	-0.23
OM&A	CD_{km^2}	-0.100	-0.124	-0.076
OM&A and Capital Proxy	$CD_{ciircuit-km}$	-0.121	-0.349	-0.225
OM&A and Capital Proxy	CD_{km^2}	-0.287	-0.151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

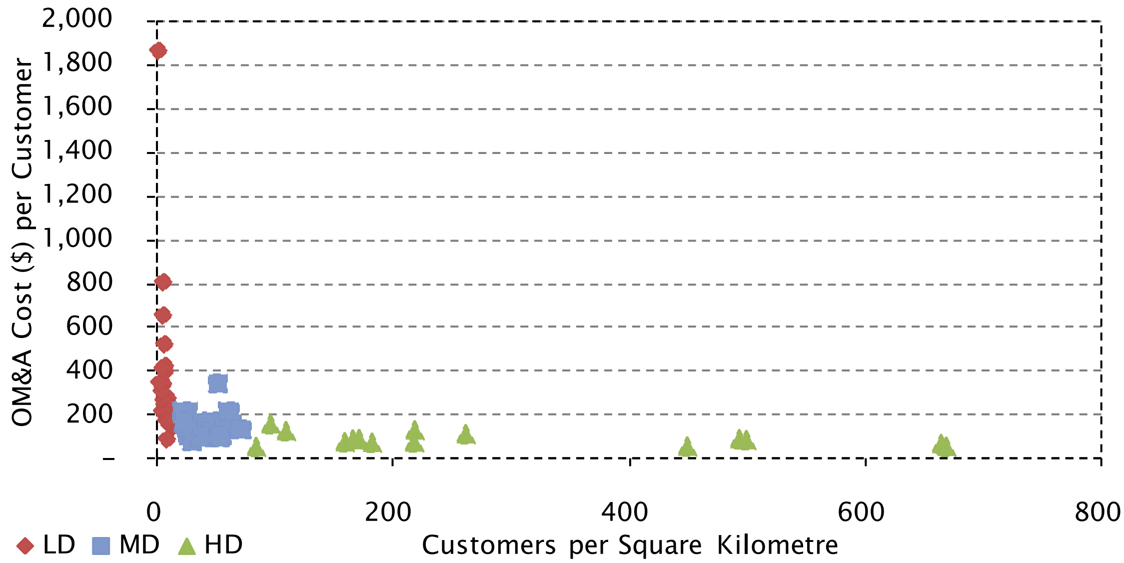
Based on the fact that the mean assigned costs for the three density level sample area groups were shown to be statistically distinct, it is appropriate for HONI to use three density differentiated rate classes (a low, medium, and high).

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.

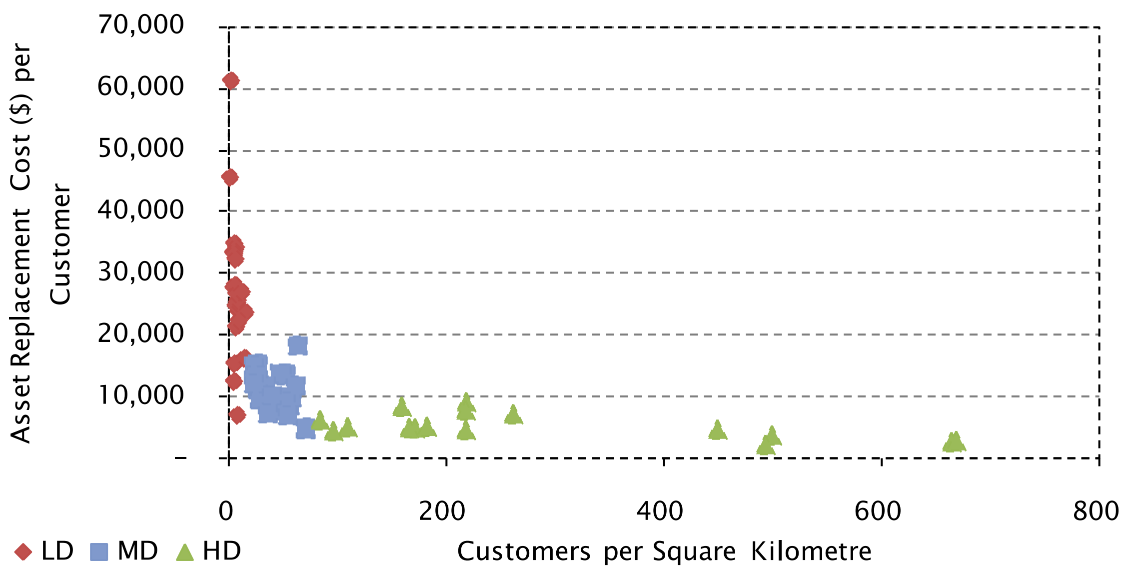
Benjamin Grunfeld/Steven Kim Mark Vainberg/Gary Ford/Andrew Poray
(416) 643-6610 (416) 487-4175
ben@londoneconomics.com markvainberg@pnxa.com

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



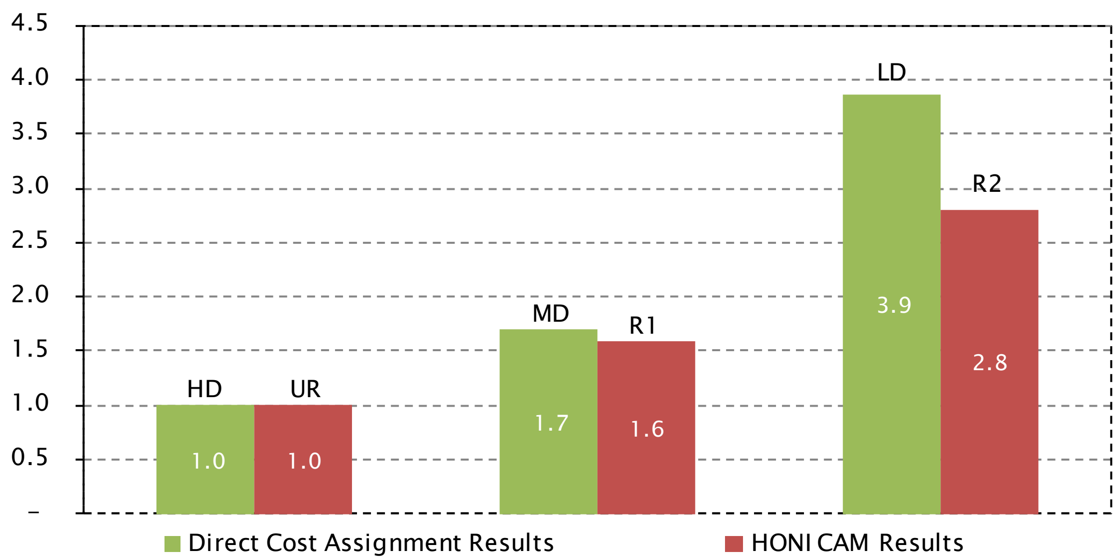
Source: LEI and PNXA analysis

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 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.

Benjamin Grunfeld/Steven Kim
(416) 643-6610
ben@londoneconomics.com
Mark Vainberg/Gary Ford/Andrew Poray
(416) 487-4175
markvainberg@pnxa.com

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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Benjamin Grunfeld/Steven Kim
(416) 643-6610
ben@londoneconomics.com

Mark Vainberg/Gary Ford/Andrew Poray
(416) 487-4175
markvainberg@pnxa.com

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London Economics International LLC
Benjamin Grunfeld/Steven Kim
(416) 643-6610
ben@londoneconomics.com

PowerNex Associates Inc.
Mark Vainberg/Gary Ford/Andrew Poray
(416) 487-4175
markvainberg@pnxa.com

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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."*

---

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.

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.).

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

Benjamin Grunfeld/Steven Kim
(416) 643-6610
ben@londoneconomics.com

Mark Vainberg/Gary Ford/Andrew Poray
(416) 487-4175
markvainberg@pnxa.com

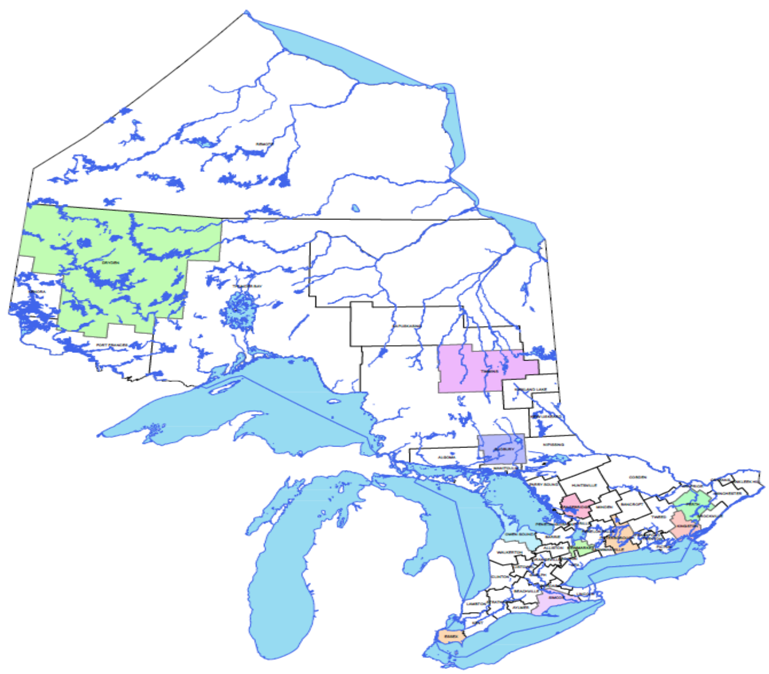
3 Summary of Econometric Analysis

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.

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:

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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

Number of Customers

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.

Energy Consumption

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

OM&A Costs

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

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]

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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

–

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.

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.

Benjamin Grunfeld/Steven Kim
(416) 643-6610
ben@londoneconomics.com

Mark Vainberg/Gary Ford/Andrew Poray
(416) 487-4175
markvainberg@pnxa.com

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.

Benjamin Grunfeld/Steven Kim
(416) 643-6610
ben@londoneconomics.com
Mark Vainberg/Gary Ford/Andrew Poray
(416) 487-4175
markvainberg@pnxa.com

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.

Benjamin Grunfeld/Steven Kim Mark Vainberg/Gary Ford/Andrew Poray
(416) 643-6610 (416) 487-4175
ben@londoneconomics.com markvainberg@pnxa.com

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.

Benjamin Grunfeld/Steven Kim Mark Vainberg/Gary Ford/Andrew Poray
(416) 643-6610 (416) 487-4175
ben@londoneconomics.com markvainberg@pnxa.com

- 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.

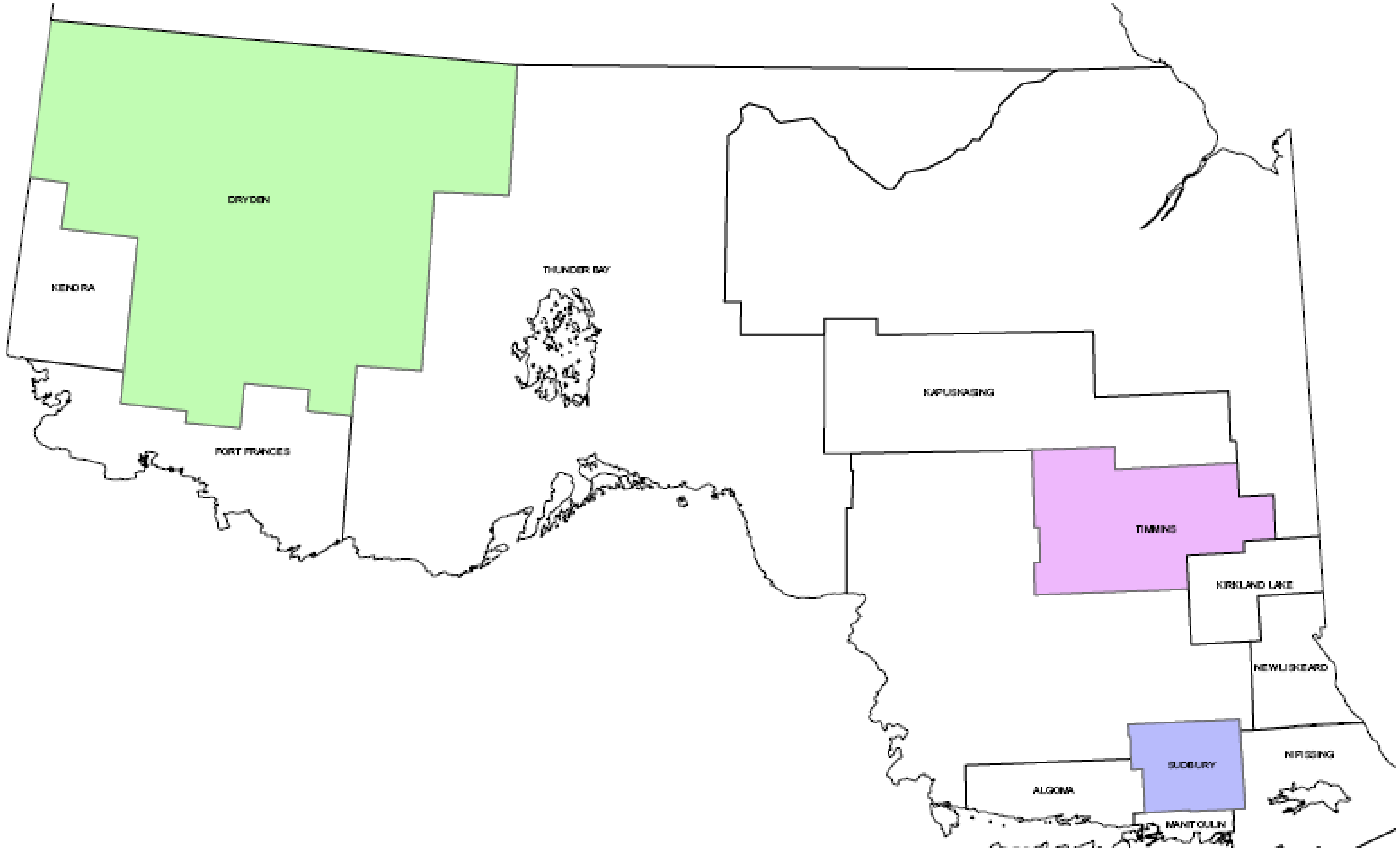
4.3.1 Operating Area Selection

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.

Figure 8: Operating Areas Selected from Northern Ontario

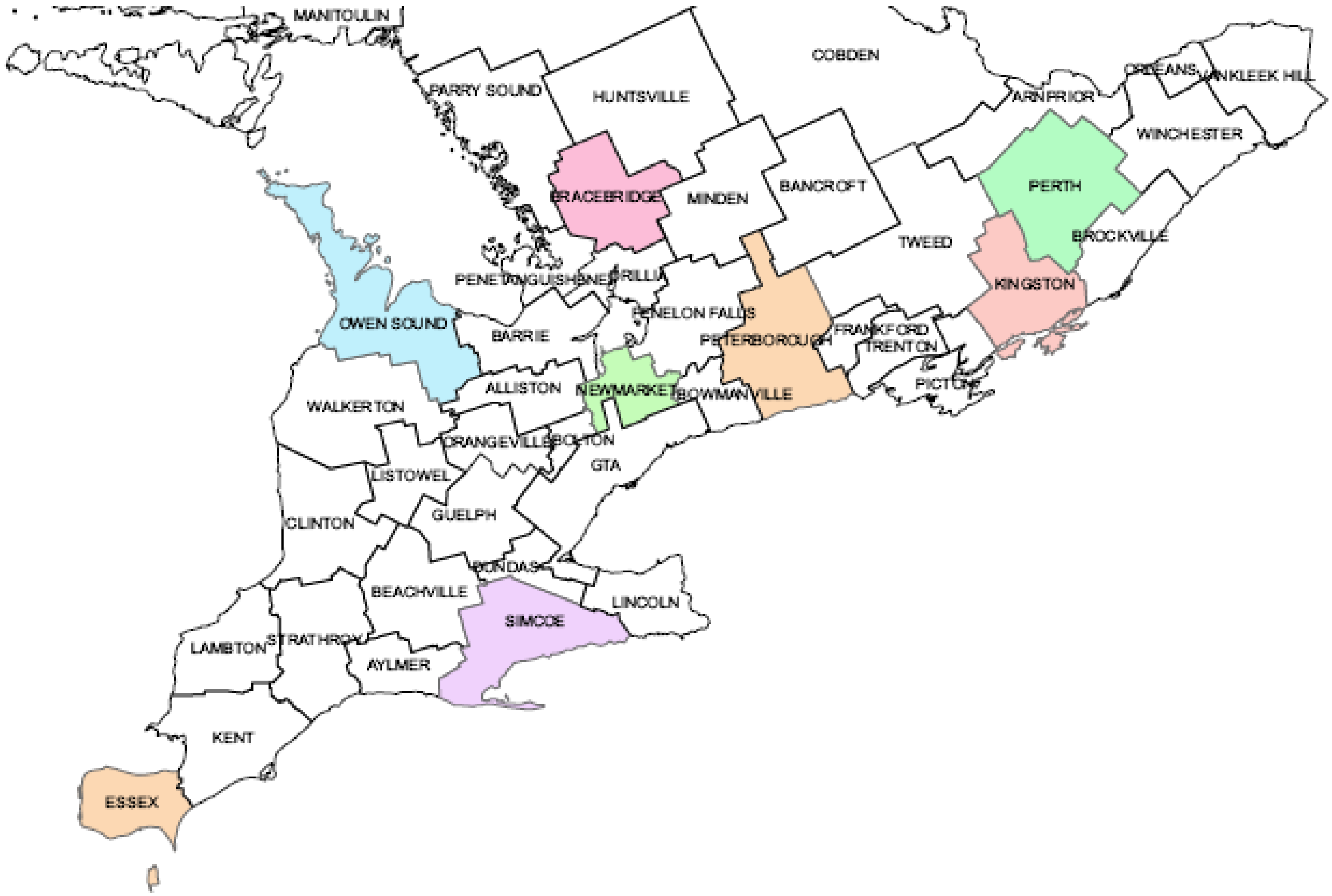


Source: HONI; LEI and PNXA analysis

London Economics International LLC
Benjamin Grunfeld/Steven Kim
(416) 643-6610
ben@londoneconomics.com

PowerNex Associates Inc.
Mark Vainberg/Gary Ford/Andrew Poray
(416) 487-4175
markvainberg@pnxa.com

Figure 9: Operating Areas Selected from Southern Ontario



Source: HONI; LEI and PNXA analysis

London Economics International LLC
Benjamin Grunfeld/Steven Kim
(416) 643-6610
ben@londoneconomics.com

PowerNex Associates Inc.
Mark Vainberg/Gary Ford/Andrew Poray
(416) 487-4175
markvainberg@pnxa.com

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.

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 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.

Benjamin Grunfeld/Steven Kim Mark Vainberg/Gary Ford/Andrew Poray
(416) 643-6610 (416) 487-4175
ben@londoneconomics.com markvainberg@pnxa.com

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.

Benjamin Grunfeld/Steven Kim Mark Vainberg/Gary Ford/Andrew Poray
(416) 643-6610 (416) 487-4175
ben@londoneconomics.com markvainberg@pnxa.com

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.

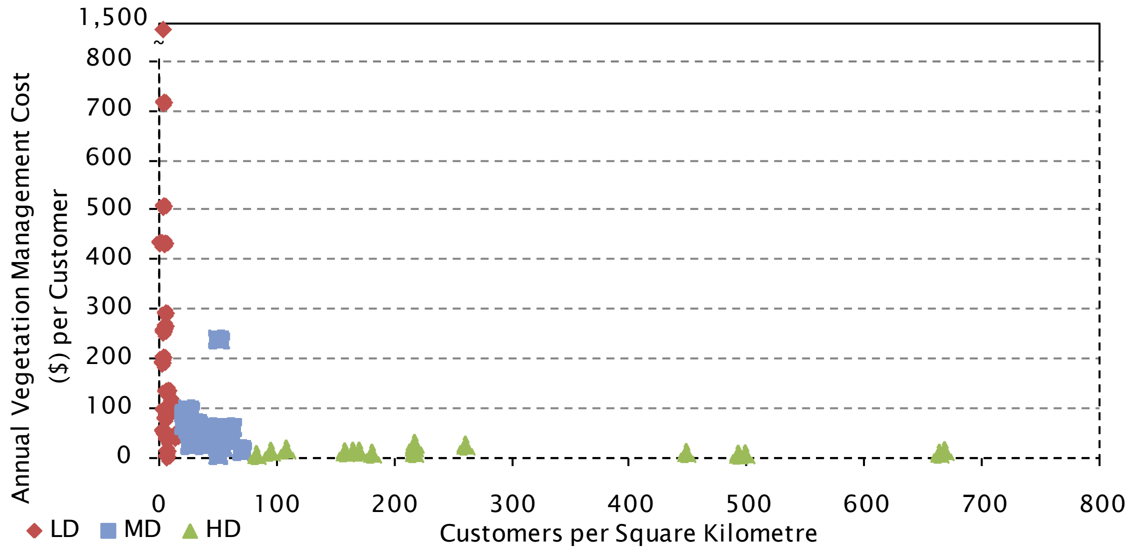
Vegetation management costs were assigned to the sample areas in a slightly different manner. Vegetation processes in HONI address tree clearing and brush control on a planned and proactive basis. Historic cost data for tree clearing and brush control covering a 10-year period were provided by HONI for 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.

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

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

Benjamin Grunfeld/Steven Kim Mark Vainberg/Gary Ford/Andrew Poray
(416) 643-6610 (416) 487-4175
ben@londoneconomics.com markvainberg@pnxa.com

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

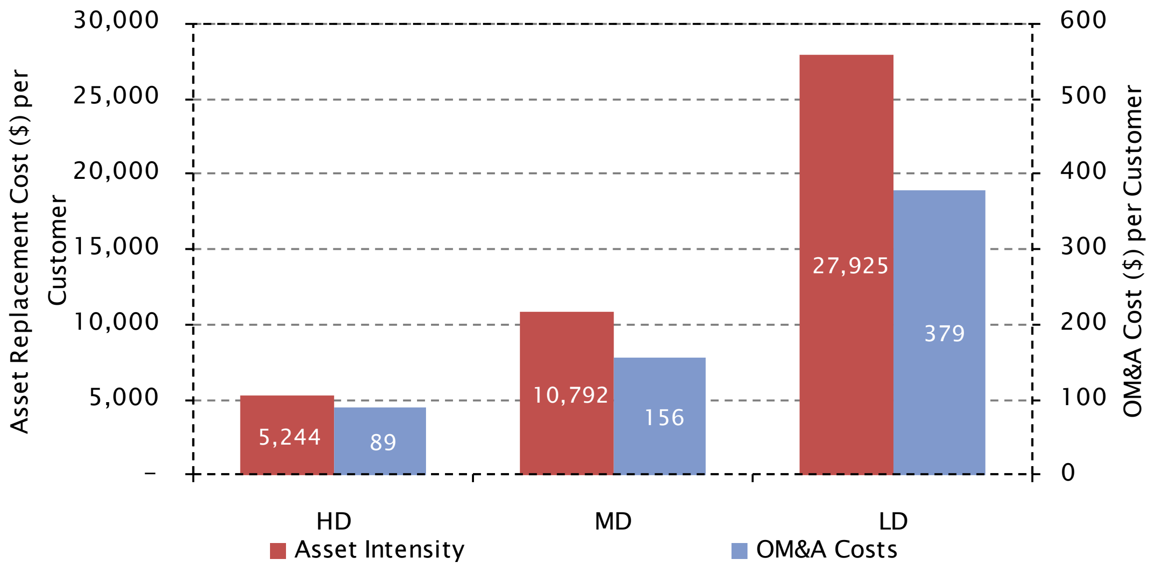
The annual results for the individual sample areas for 2006 through 2010 were averaged to minimize the impact of the cyclical nature of some work programs on the study results.

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.

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

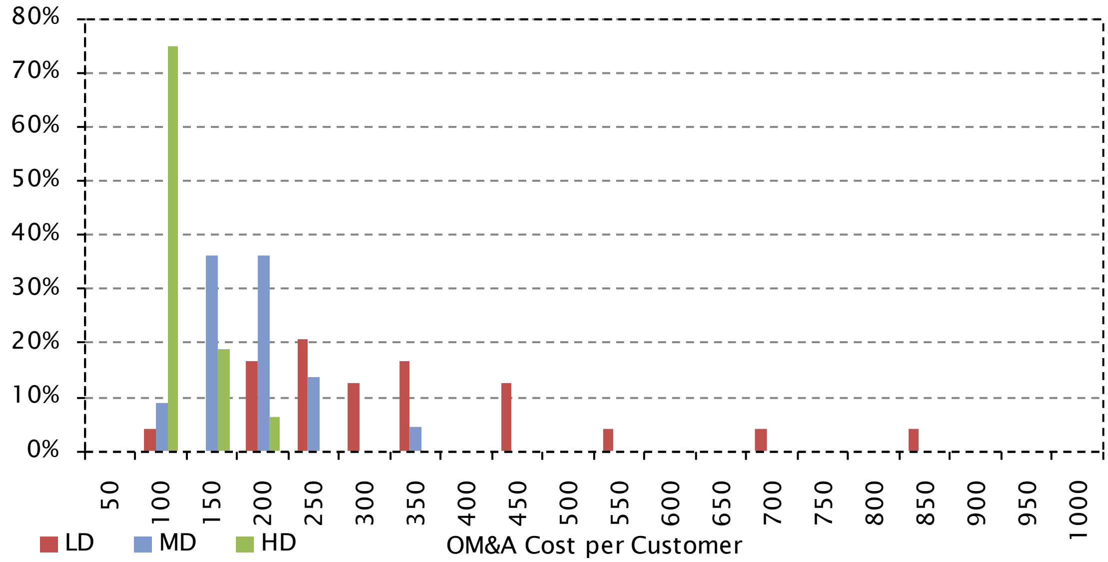


Source: LEI and PNXA analysis

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.

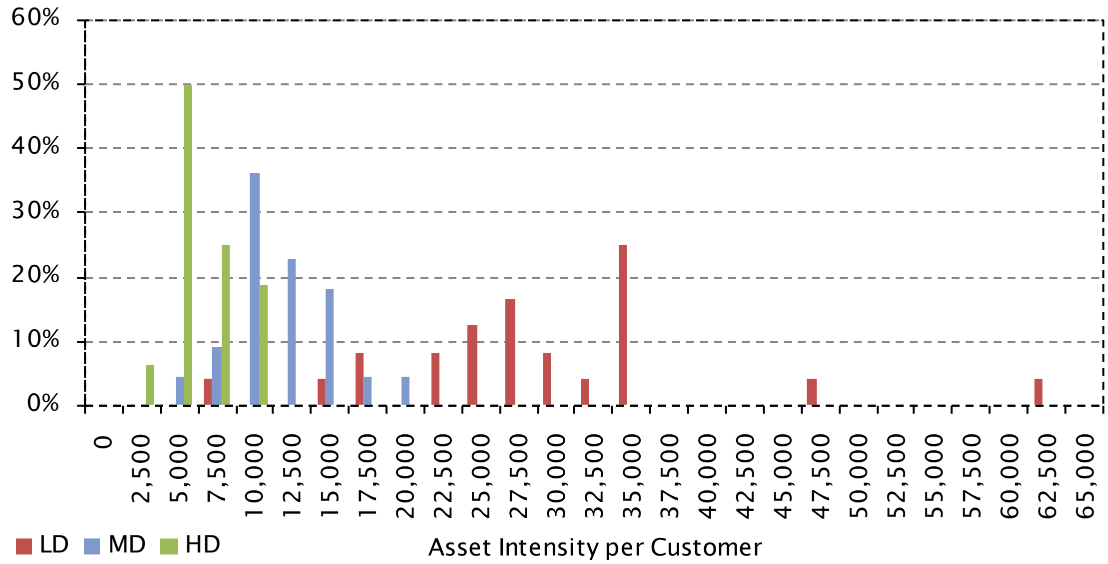
With this overlap present, further analysis was required to determine if the mean values of the distributions are in fact different, from a statistical standpoint. That is, could it be reasonably concluded that the high-density sample area mean value is different and less than the medium-density sample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

Benjamin Grunfeld/Steven Kim
(416) 643-6610
ben@londoneconomics.com

Mark Vainberg/Gary Ford/Andrew Poray
(416) 487-4175
markvainberg@pnxa.com

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

Benjamin Grunfeld/Steven Kim
(416) 643-6610
ben@londoneconomics.com
Mark Vainberg/Gary Ford/Andrew Poray
(416) 487-4175
markvainberg@pnxa.com

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

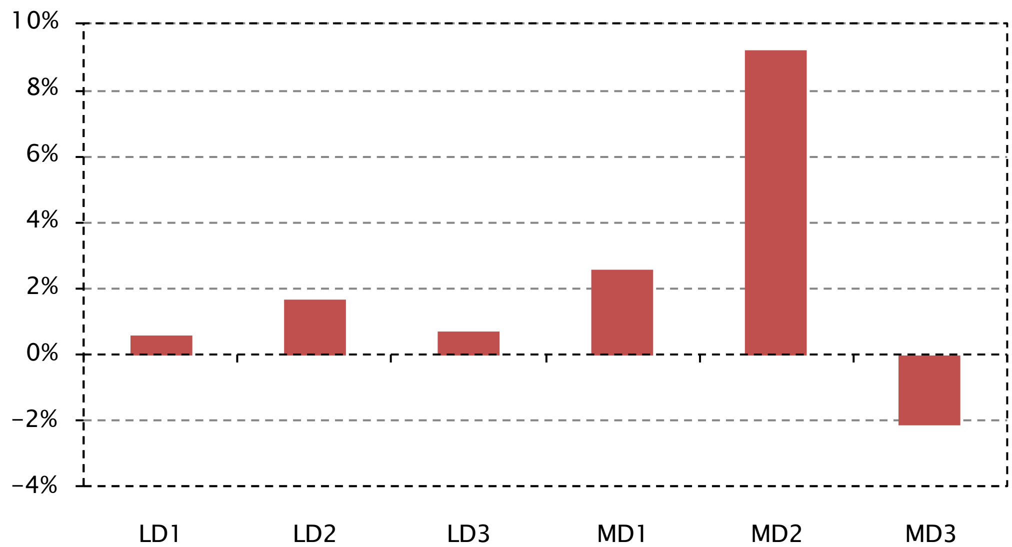
One of the assumptions in the direct cost assignment method is that some of HONI's OM&A expenses are proportional to the distance from the customer (or asset) to the closest service centre. Costs relating to trouble calls, pole maintenance, patrol and inspection, etc. were all assigned using distance 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.

Benjamin Grunfeld/Steven Kim Mark Vainberg/Gary Ford/Andrew Poray
(416) 643-6610 (416) 487-4175
ben@londoneconomics.com markvainberg@pnxa.com

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



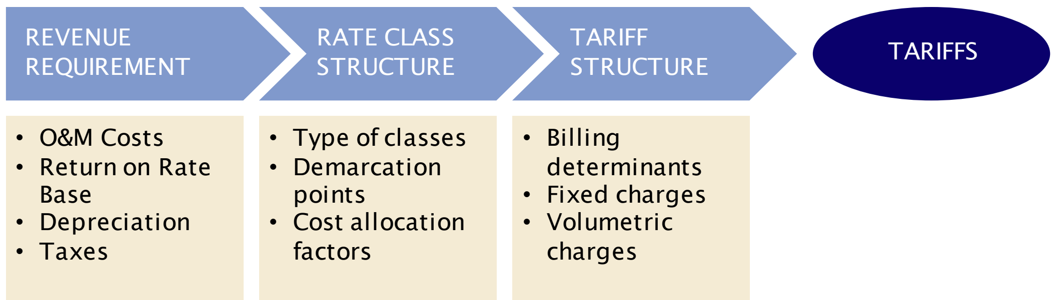
Source: LEI and PNXA analysis

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:

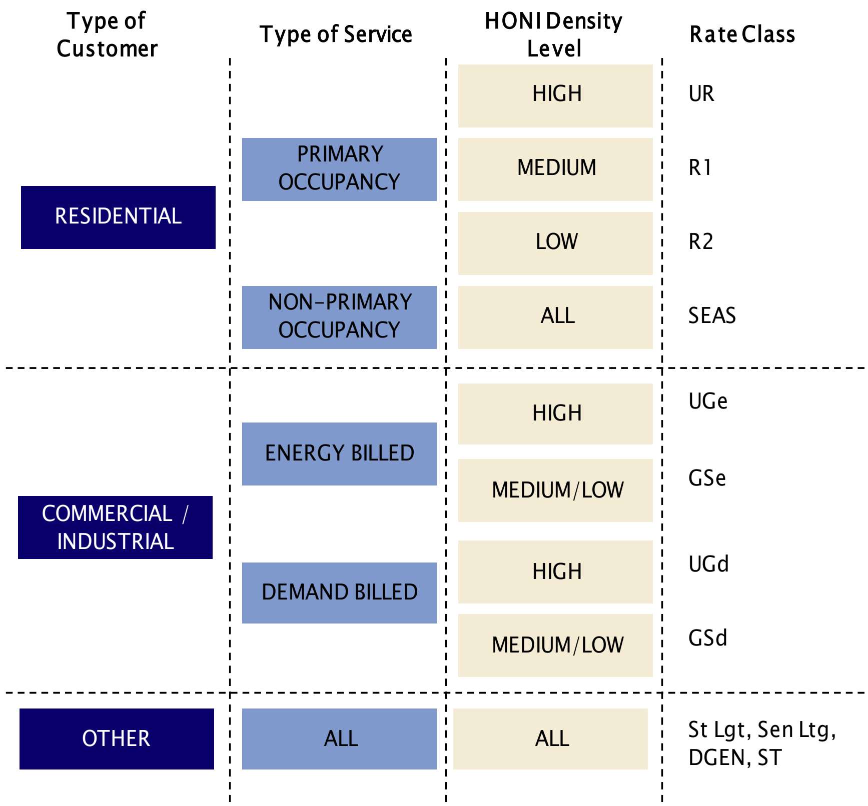
- the number and type of rate classes that are utilized;
- the demarcation points between the various rate classes; and
- the cost allocation factors that assign costs to the different classes.

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.

London Economics International LLC
Benjamin Grunfeld/Steven Kim
(416) 643-6610
ben@londoneconomics.com

PowerNex Associates Inc.
Mark Vainberg/Gary Ford/Andrew Poray
(416) 487-4175
markvainberg@pnxa.com

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.

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.

Benjamin Grunfeld/Steven Kim
(416) 643-6610
ben@londoneconomics.com
Mark Vainberg/Gary Ford/Andrew Poray
(416) 487-4175
markvainberg@pnxa.com

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.

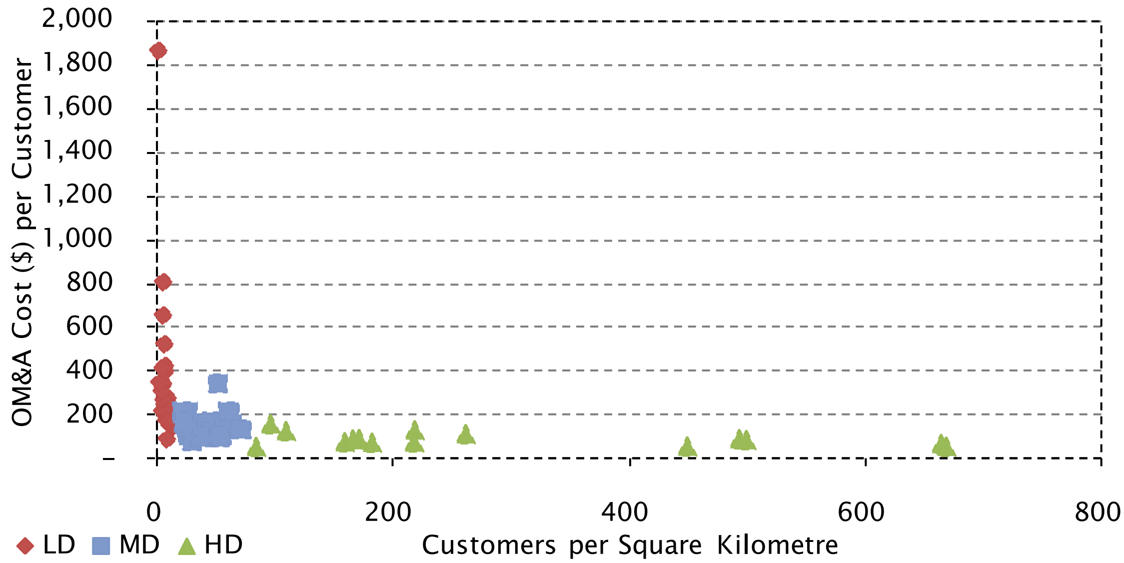
Figure 24 below illustrates the relationship between the per-customer assigned OM&A costs and customer density (measured by the number of customers per square kilometre) for the sample areas. Similarly, Figure 25 shows the relationship between the per-customer asset replacement costs and customer density 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.

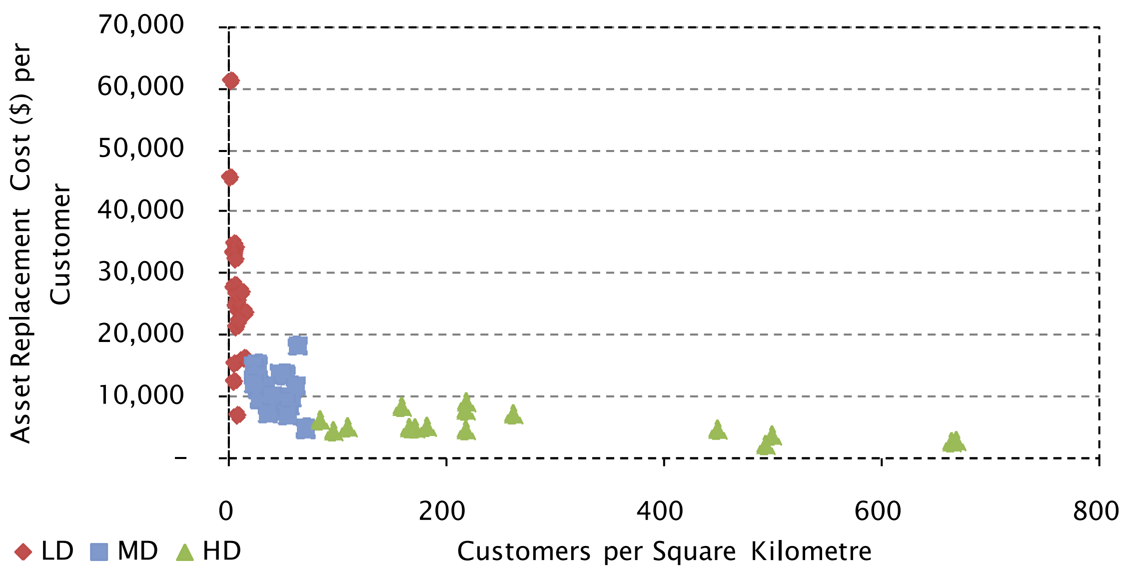
Benjamin Grunfeld/Steven Kim Mark Vainberg/Gary Ford/Andrew Poray
(416) 643-6610 (416) 487-4175
ben@londoneconomics.com markvainberg@pnxa.com

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 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.

Benjamin Grunfeld/Steven Kim Mark Vainberg/Gary Ford/Andrew Poray
(416) 643-6610 (416) 487-4175
ben@londoneconomics.com markvainberg@pnxa.com

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.

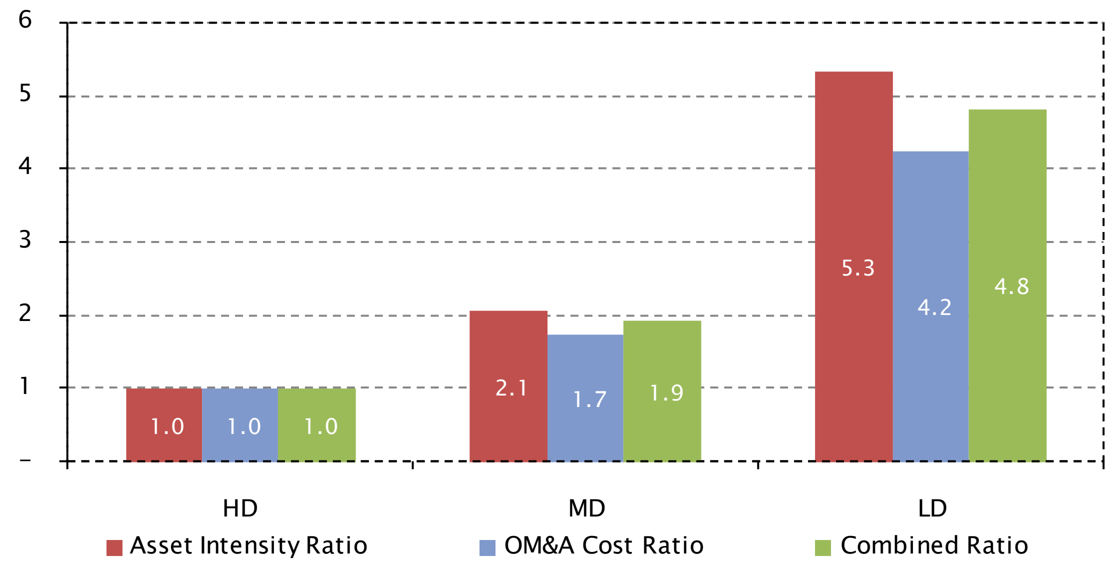
- The OM&A costs for the high-, medium-, and low-density sample areas need to be adjusted to reflect all of the costs considered in the CAM. The excluded costs, which primarily consist of shared services and customer care, are estimated to be approximately $162 ($2010) per customer, on average between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

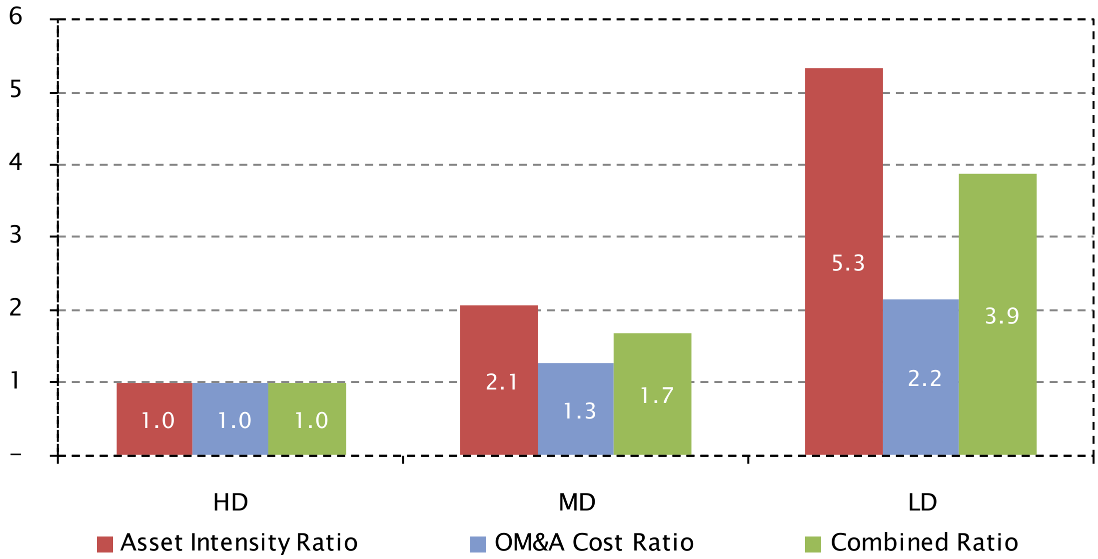
Figure 28 illustrates the ratios after including the uniform adjustment for shared services and customer care OM&A costs. The ratio between the low- and high-density sample area combined mean directly assigned asset intensity and OM&A cost is 3.9, whereas the ratio between the medium- and high-density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

Figure 28: Adjusted Ratio of Average Sample Area Costs



Source: LEI and PNXA analysis

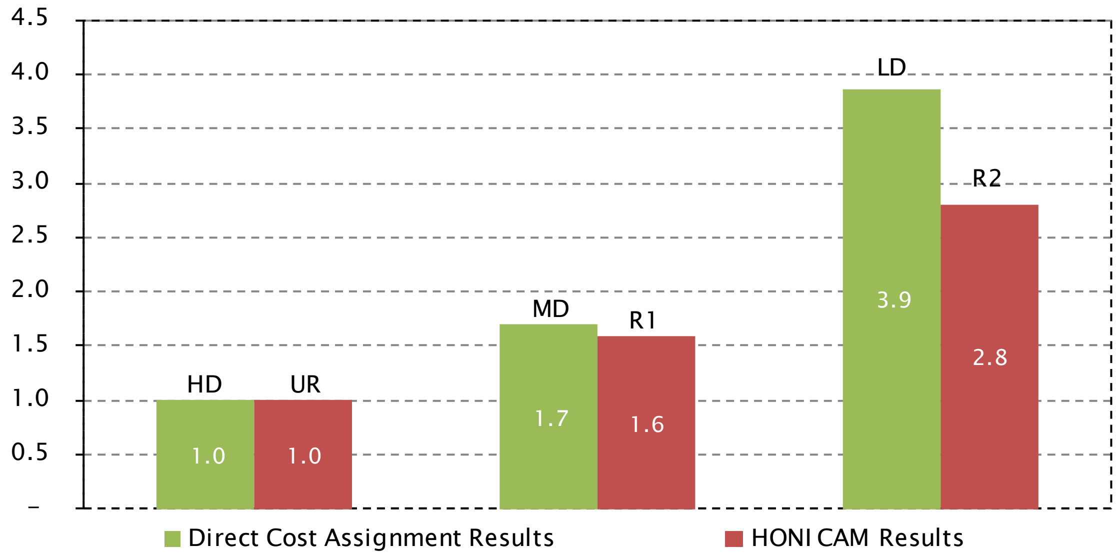
As a result, the proportion of HONI's service territory that has a density of less than 100 customers per 20 square kilometres is likely underrepresented by the low-density sample areas. As a result, the mean density of the low-density sample areas likely overstates the mean density of the service territory 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

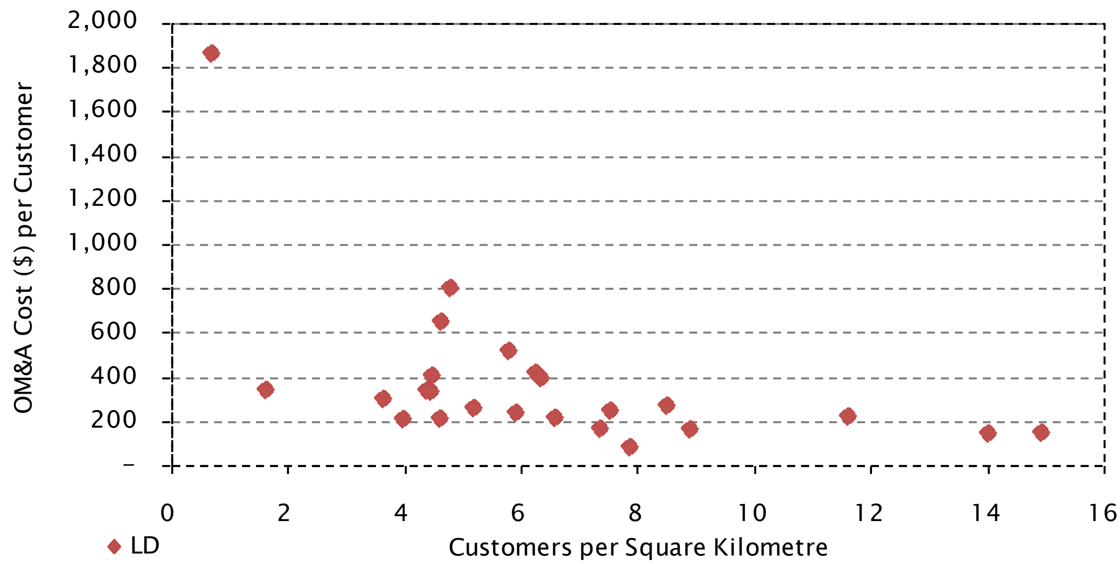
As discussed in Section 5.1.2, the results of the direct cost assignment analysis reveal considerable variability in the estimated cost to serve low-density sample areas. While there is not enough evidence available in the current study to draw firm conclusions on this specific issue, additional low-density 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.

Benjamin Grunfeld/Steven Kim Mark Vainberg/Gary Ford/Andrew Poray
(416) 643-6610 (416) 487-4175
ben@londoneconomics.com markvainberg@pnxa.com

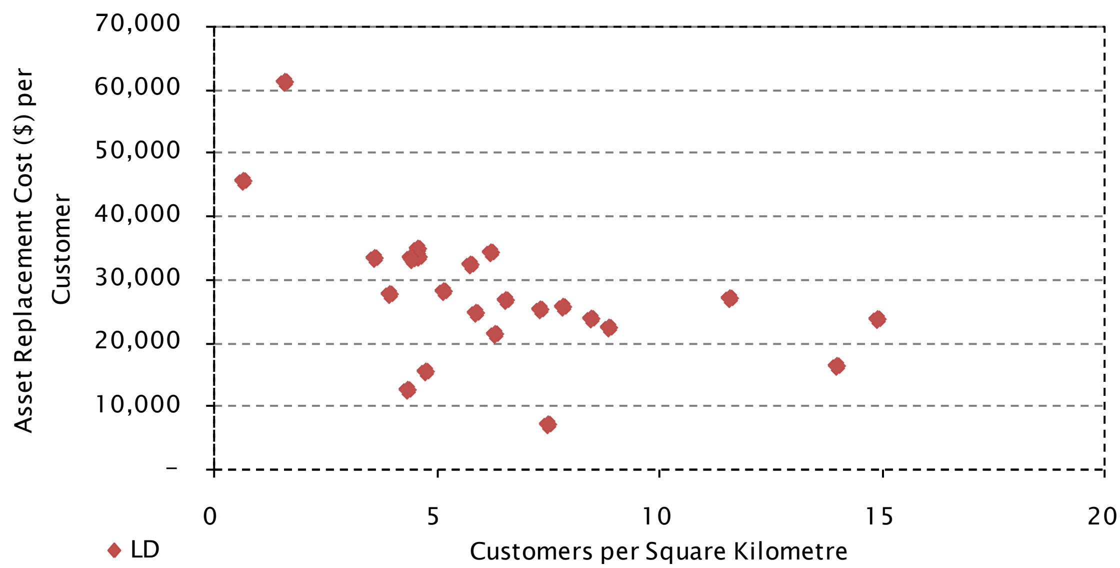
Another possible adjustment to HONI's existing structure could be to refine the demarcation point which establishes the high-density rate classes. The original basis for the 3,000 customer definition appears to be based on the average LDC size at the time the concept of urban-density zones was first 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.

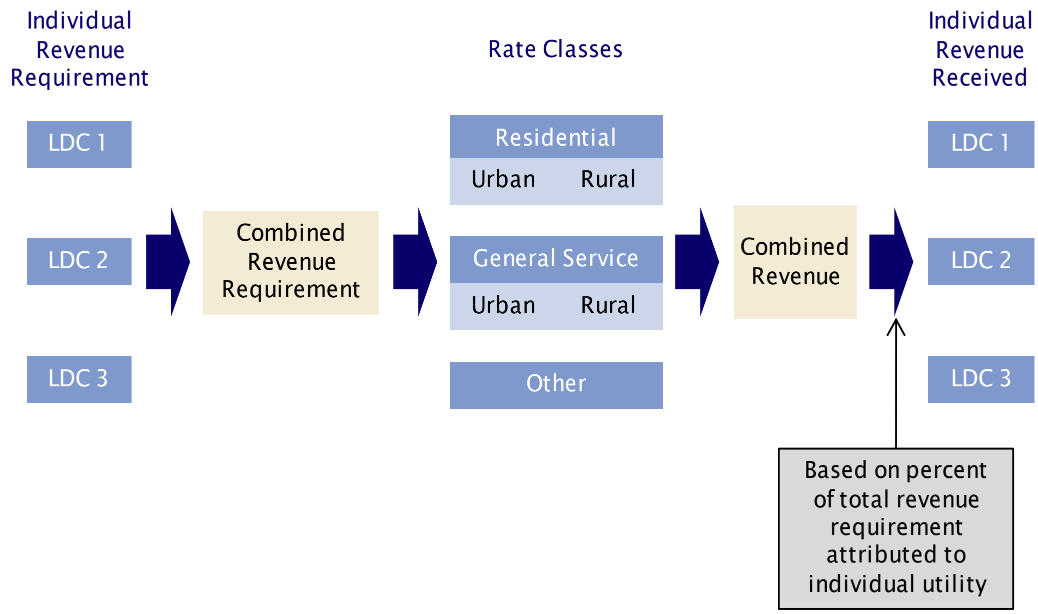
6.1.3 Regional Rates

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

Benjamin Grunfeld/Steven Kim Mark Vainberg/Gary Ford/Andrew Poray
(416) 643-6610 (416) 487-4175
ben@londoneconomics.com markvainberg@pnxa.com

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

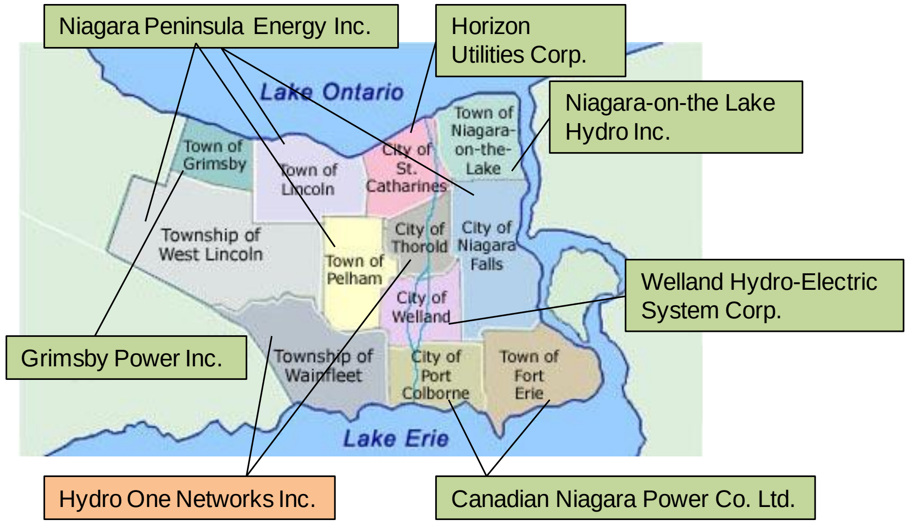


The rate classes could also be established to maintain differences between urban and rural (high- and low-density) customers. Again a precedent exists in the electricity transmission sector where there are separate rates for connection, transformation, and network services.

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.

London Economics International LLC
Benjamin Grunfeld/Steven Kim
(416) 643-6610
ben@londoneconomics.com

PowerNex Associates Inc.
Mark Vainberg/Gary Ford/Andrew Poray
(416) 487-4175
markvainberg@pnxa.com

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

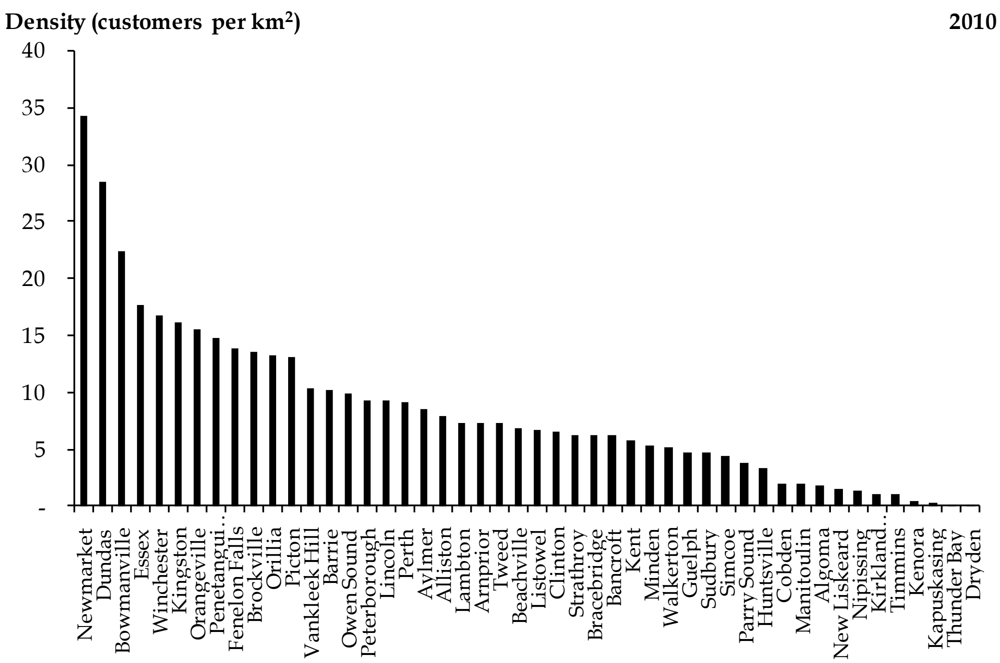
If one hypothesized that distribution service costs were linearly influenced by the number of customers and customer density, Equation 3 below would be the functional form. The parameter (or coefficient) "A" is the intercept term. The presence of a positive value for the "A" intercept means that there 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

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

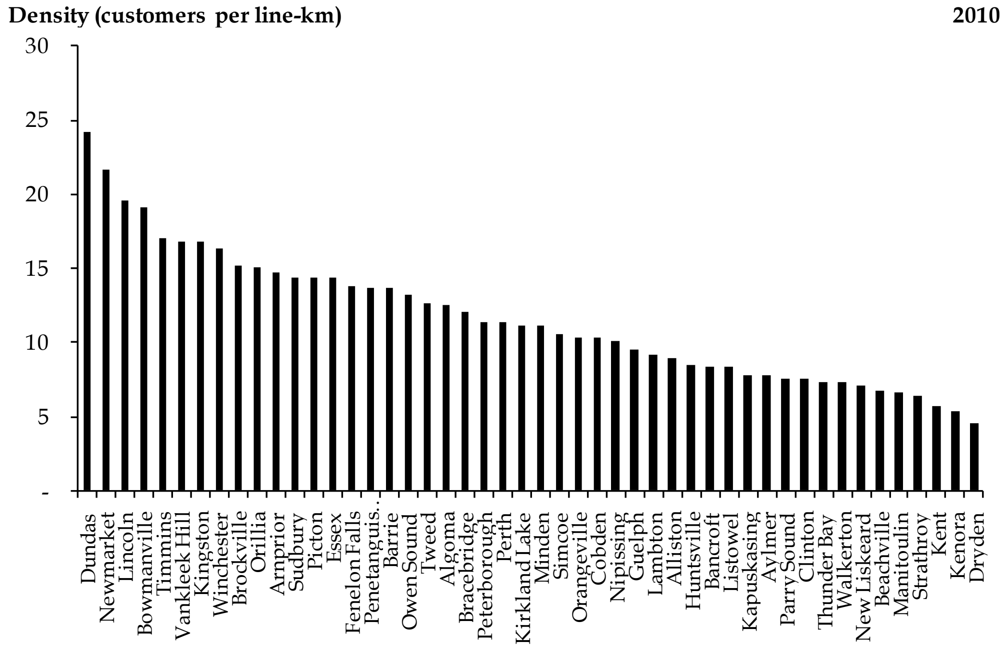
Figure 34: Operating Area 2010 Customer Density (per square kilometre)



Source: HONI; LEI and PNXA analysis

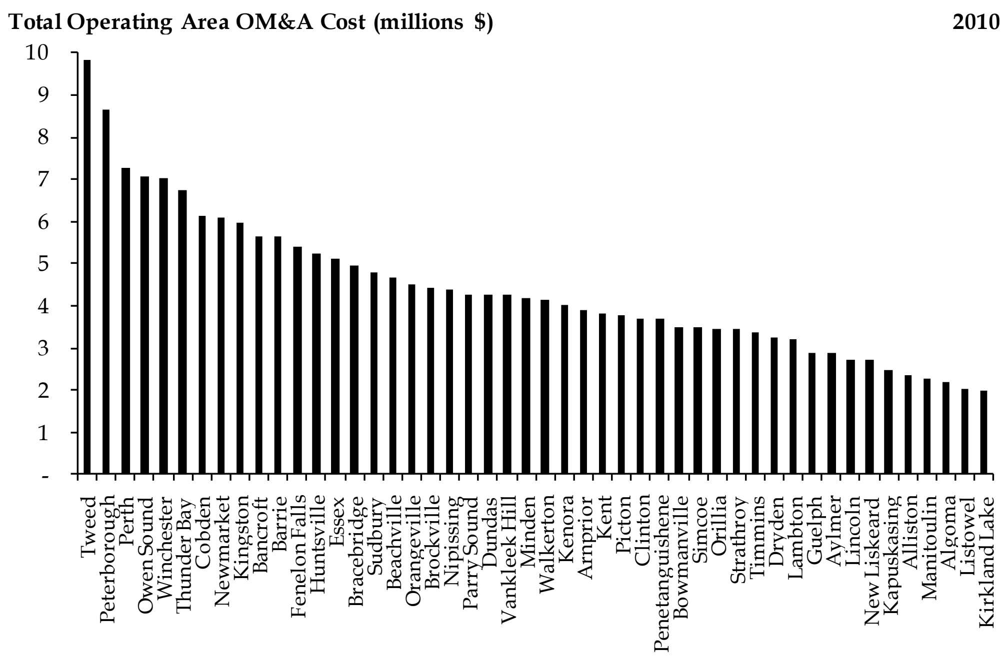
Benjamin Grunfeld/Steven Kim
(416) 643-6610
ben@londoneconomics.com
Mark Vainberg/Gary Ford/Andrew Poray
(416) 487-4175
markvainberg@pnxa.com

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



Source: HONI; LEI and PNXA analysis

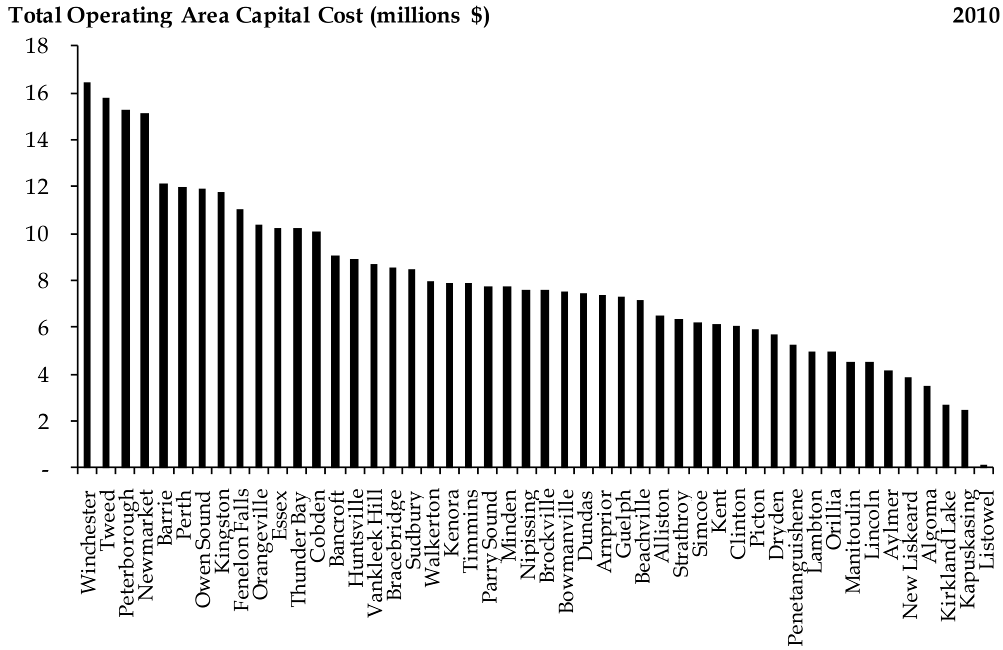
Figure 36: Operating Area 2010 OM&A Cost



Source: HONI; LEI and PNXA analysis

Benjamin Grunfeld/Steven Kim
Mark Vainberg/Gary Ford/Andrew Poray
(416) 643-6610
(416) 487-4175
ben@londoneconomics.com
markvainberg@pnxa.com

Figure 37: Operating Area 2010 Capital Proxy



Source: HONI; LEI and PNXA analysis

London Economics International LLC
Benjamin Grunfeld/Steven Kim
(416) 643-6610
ben@londoneconomics.com

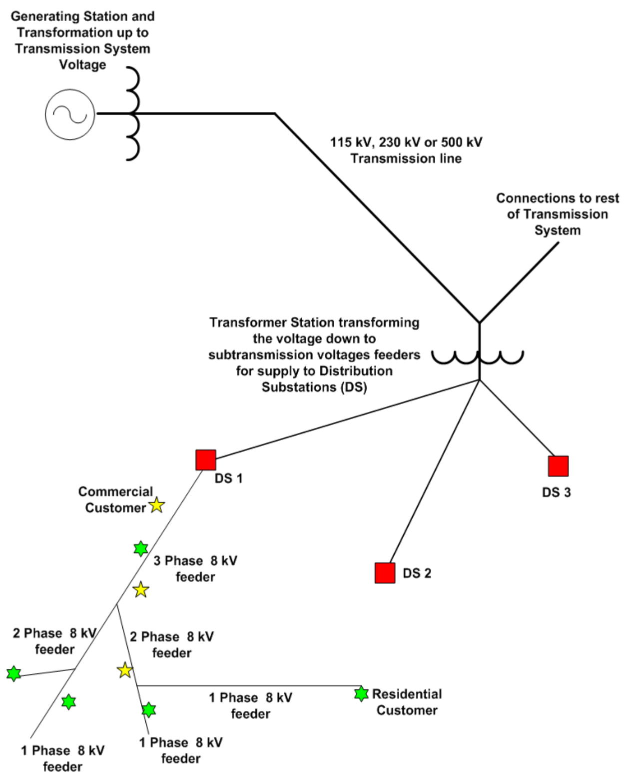
PowerNex Associates Inc.
Mark Vainberg/Gary Ford/Andrew Poray
(416) 487-4175
markvainberg@pnxa.com

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.

Benjamin Grunfeld/Steven Kim Mark Vainberg/Gary Ford/Andrew Poray
(416) 643-6610 (416) 487-4175
ben@londoneconomics.com markvainberg@pnxa.com

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.

Benjamin Grunfeld/Steven Kim Mark Vainberg/Gary Ford/Andrew Poray
(416) 643-6610 (416) 487-4175
ben@londoneconomics.com markvainberg@pnxa.com

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.

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

Source: PNXA files

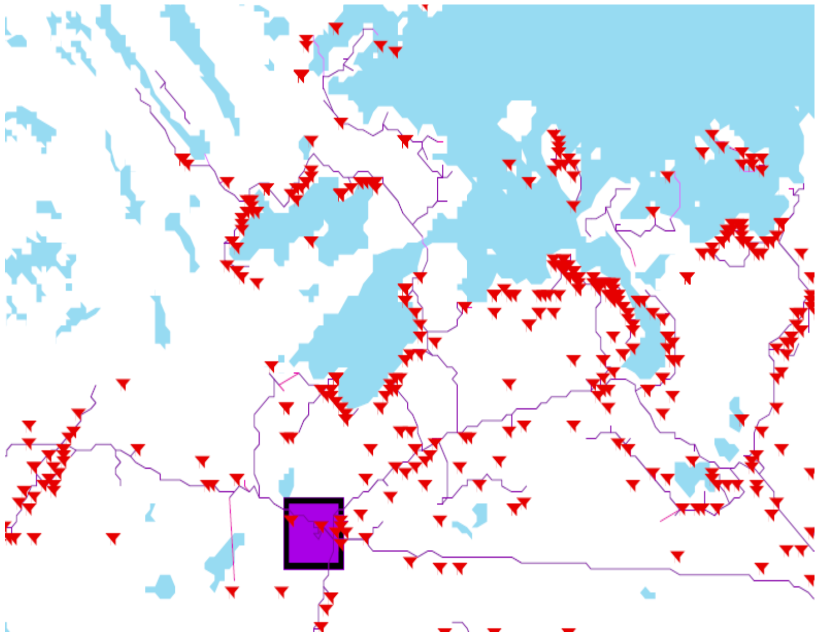
Operation and Maintenance of Distribution Systems

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.

Figure 42: Typical Radial Feeder Topology in Northern Ontario

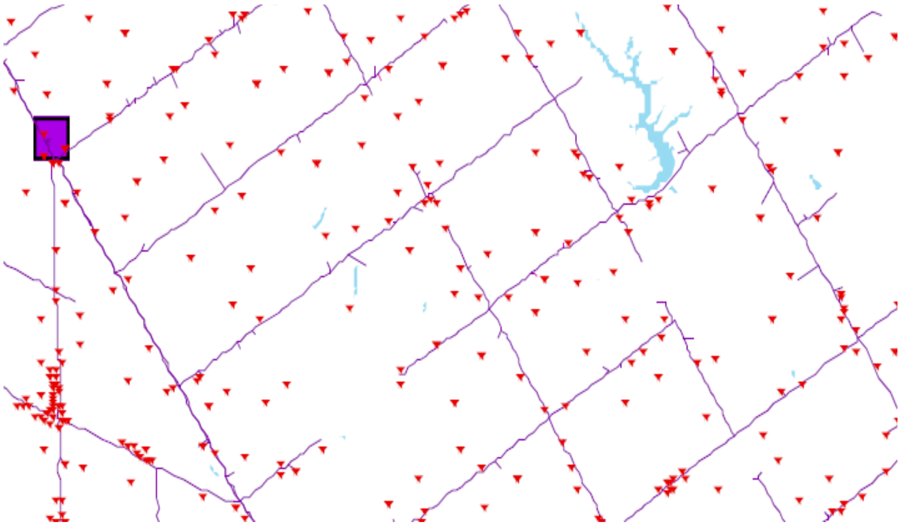


Notes: Feeders are shown as lines, triangles represent transformers feeding customers, and the purple rectangle indicates the distribution station
Source: HONI

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.

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.

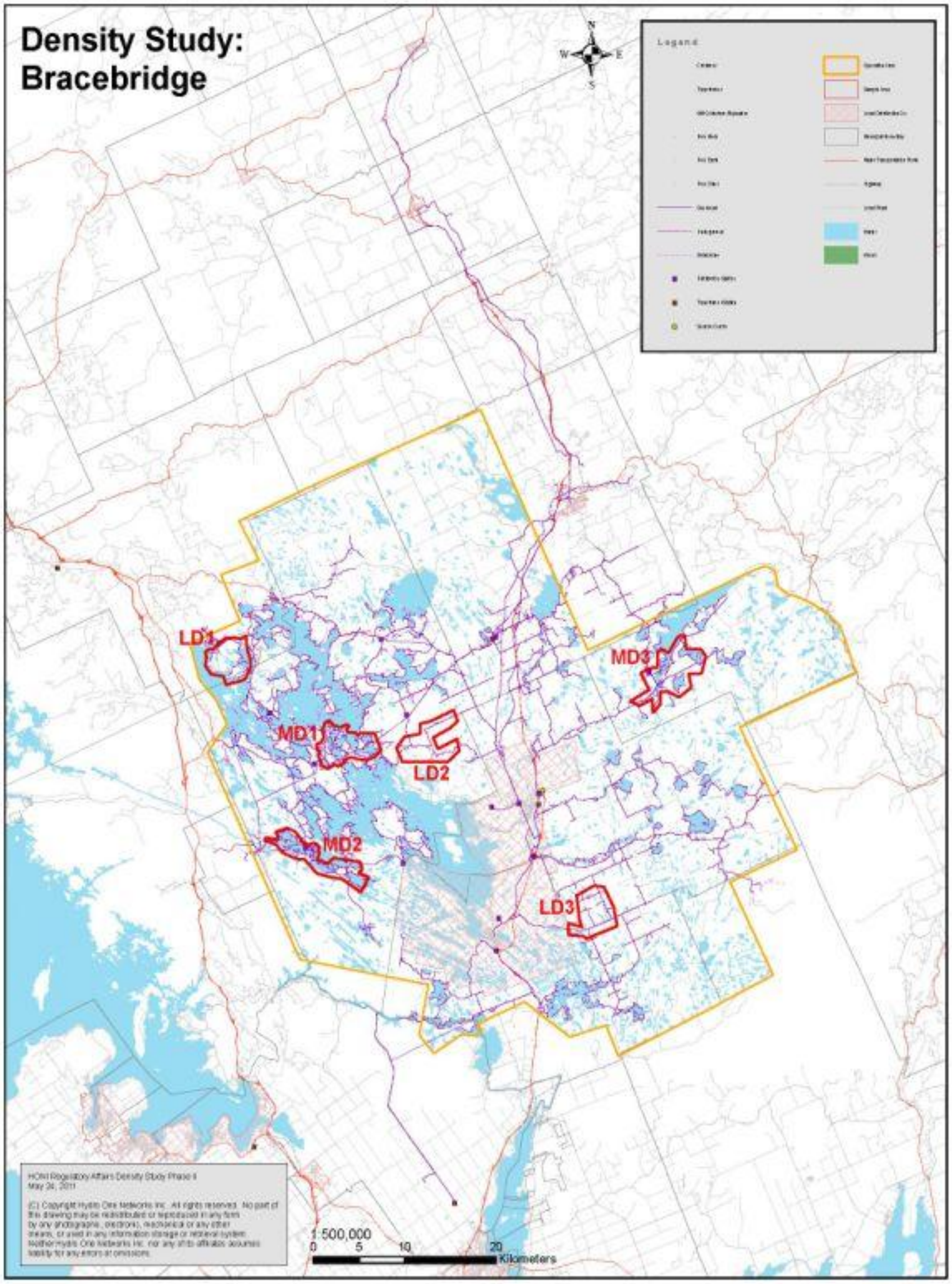
Figure 44: Typical Off Road Rights of Way

Source: PNXA files

Appendix C – Direct Cost Assignment Analysis Details

Sample Area Maps

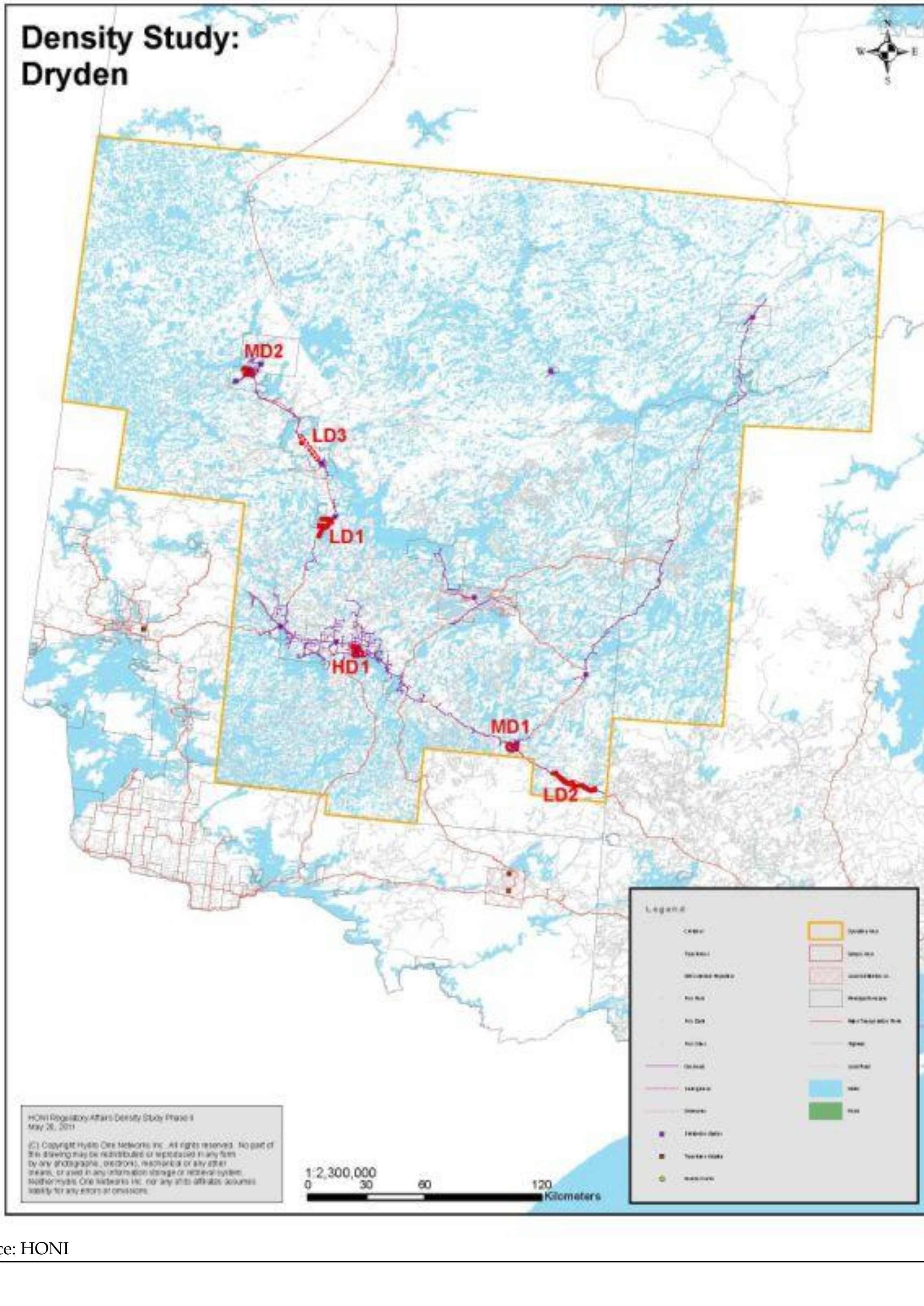
Figure 45: Bracebridge Operating Area Map



Source: HONI

Benjamin Grunfeld/Steven Kim
(416) 643-6610
ben@londoneconomics.com
Mark Vainberg/Gary Ford/Andrew Poray
(416) 487-4175
markvainberg@pnxa.com

Figure 46: Dryden Operating Area Map



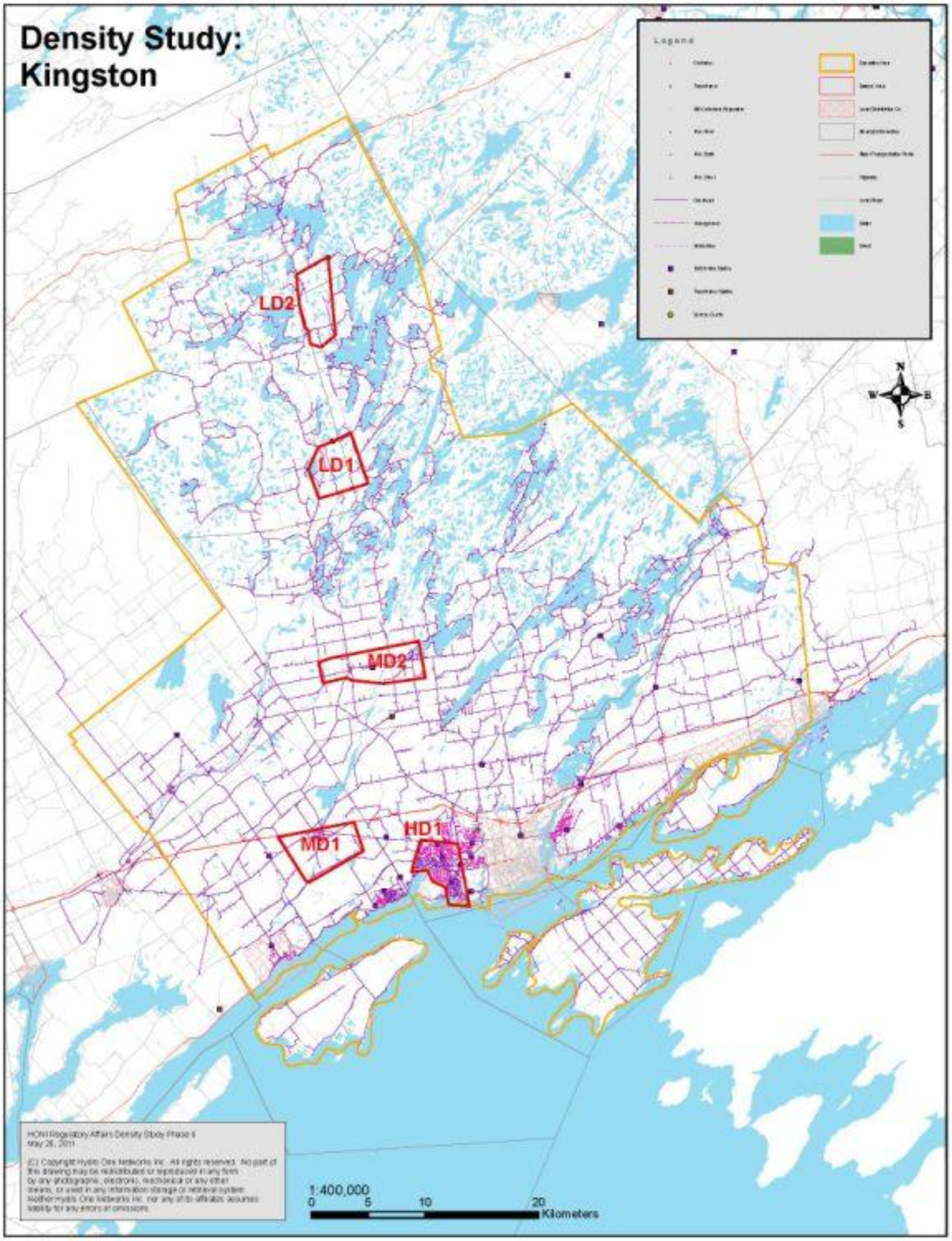
Source: HONI

Benjamin Grunfeld/Steven Kim
(416) 643-6610
ben@londoneconomics.com
Mark Vainberg/Gary Ford/Andrew Poray
(416) 487-4175
markvainberg@pnxa.com

Figure 47: Essex Operating Area Map

Source: HONI

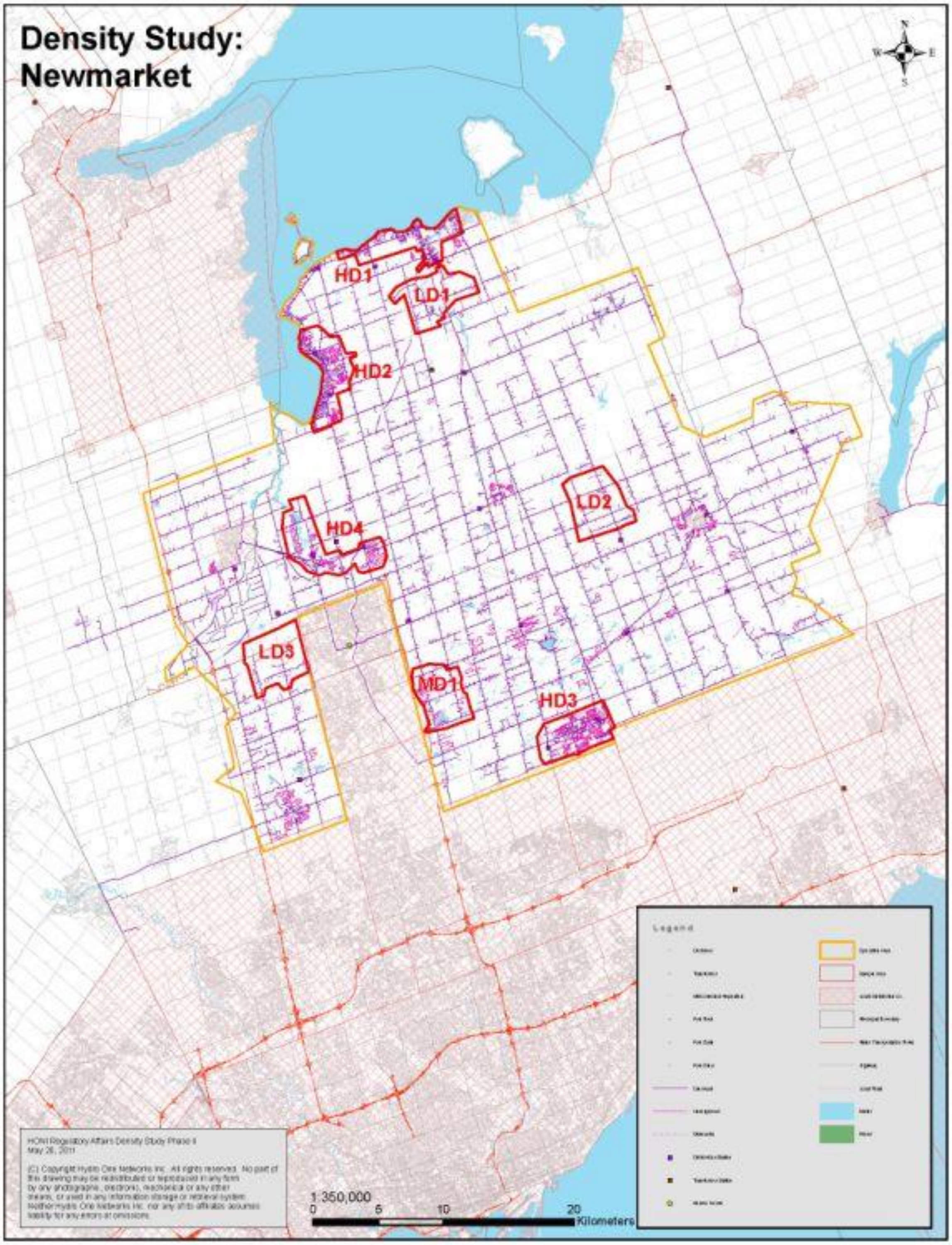
Figure 48: Kingston Operating Area Map



Source: HONI

Benjamin Grunfeld/Steven Kim
(416) 643-6610
ben@londoneconomics.com
Mark Vainberg/Gary Ford/Andrew Poray
(416) 487-4175
markvainberg@pnxa.com

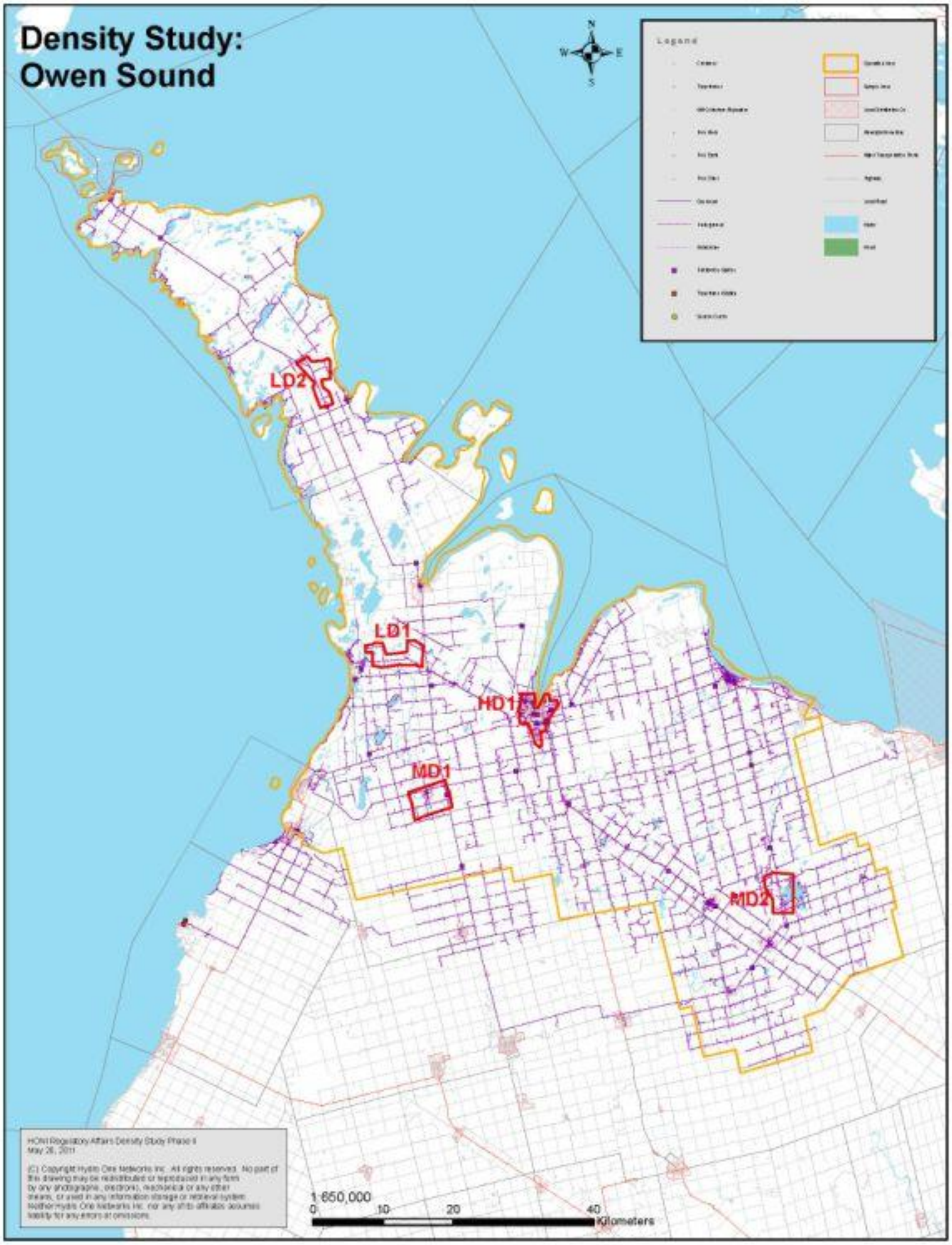
Figure 49: Newmarket Operating Area Map



Source: HONI

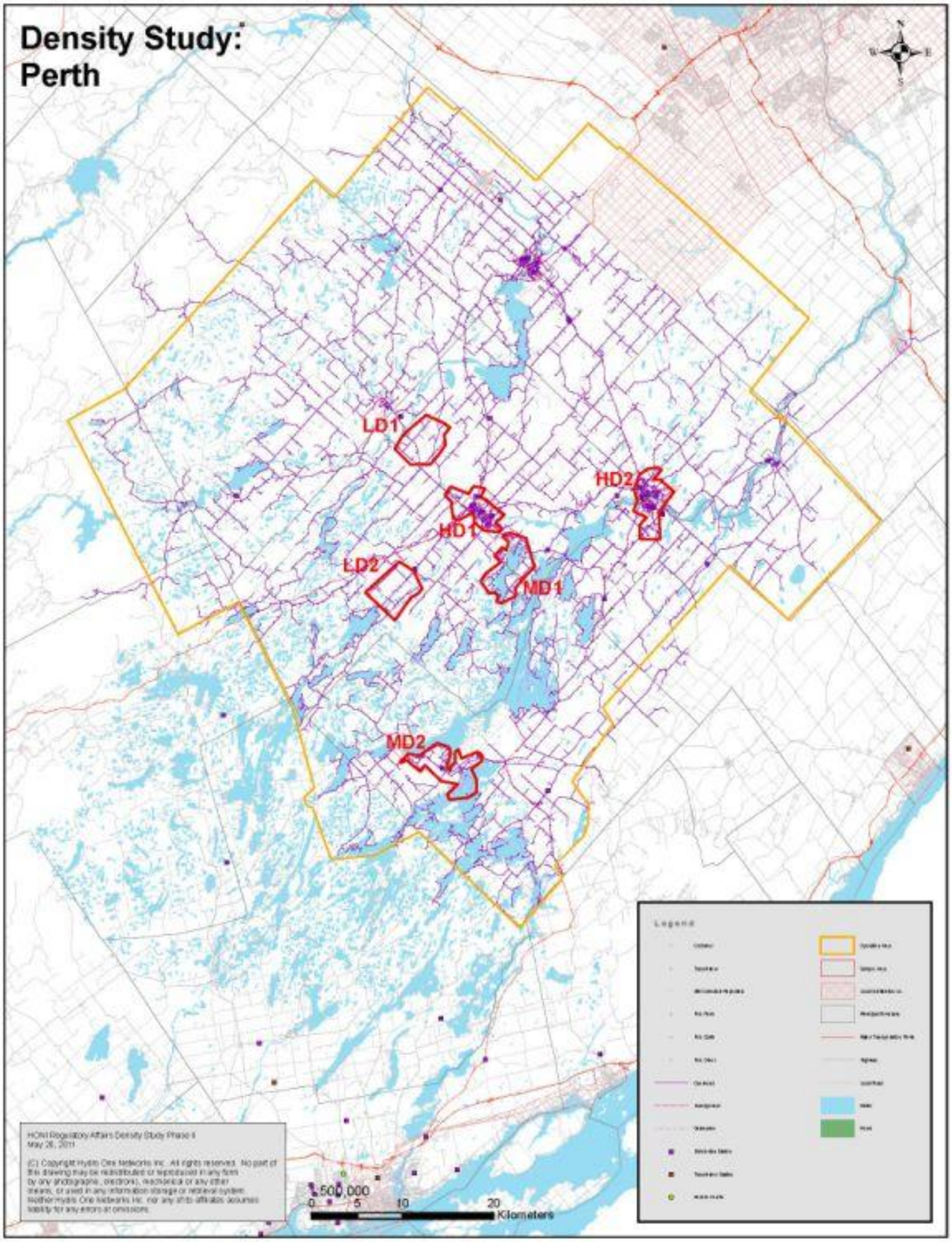
Benjamin Grunfeld/Steven Kim
(416) 643-6610
ben@londoneconomics.com
Mark Vainberg/Gary Ford/Andrew Poray
(416) 487-4175
markvainberg@pnxa.com

Figure 50: Owen Sound Operating Area Map



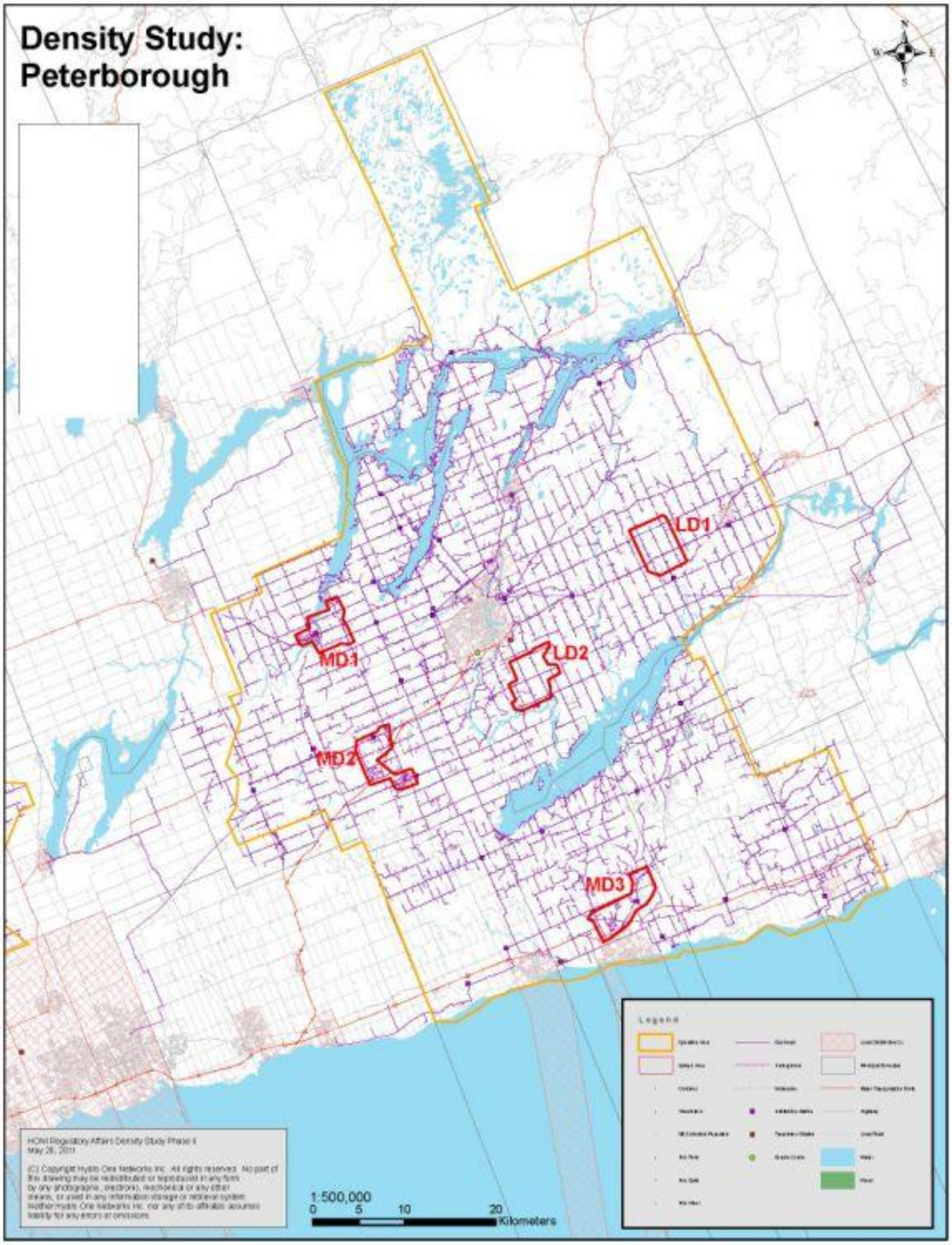
Source: HONI

Figure 51: Perth Operating Area Map



Source: HONI

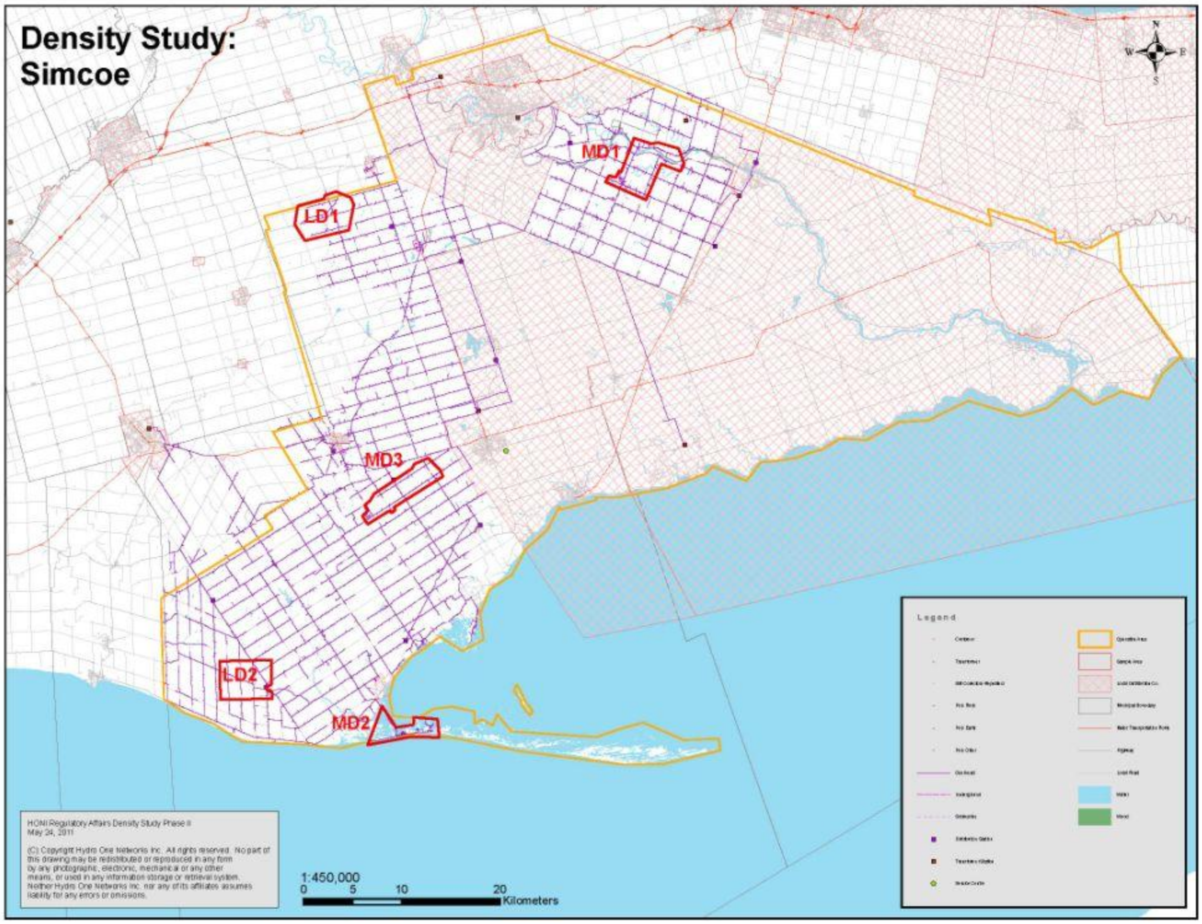
Figure 52: Peterborough Operating Area Map



Source: HONI

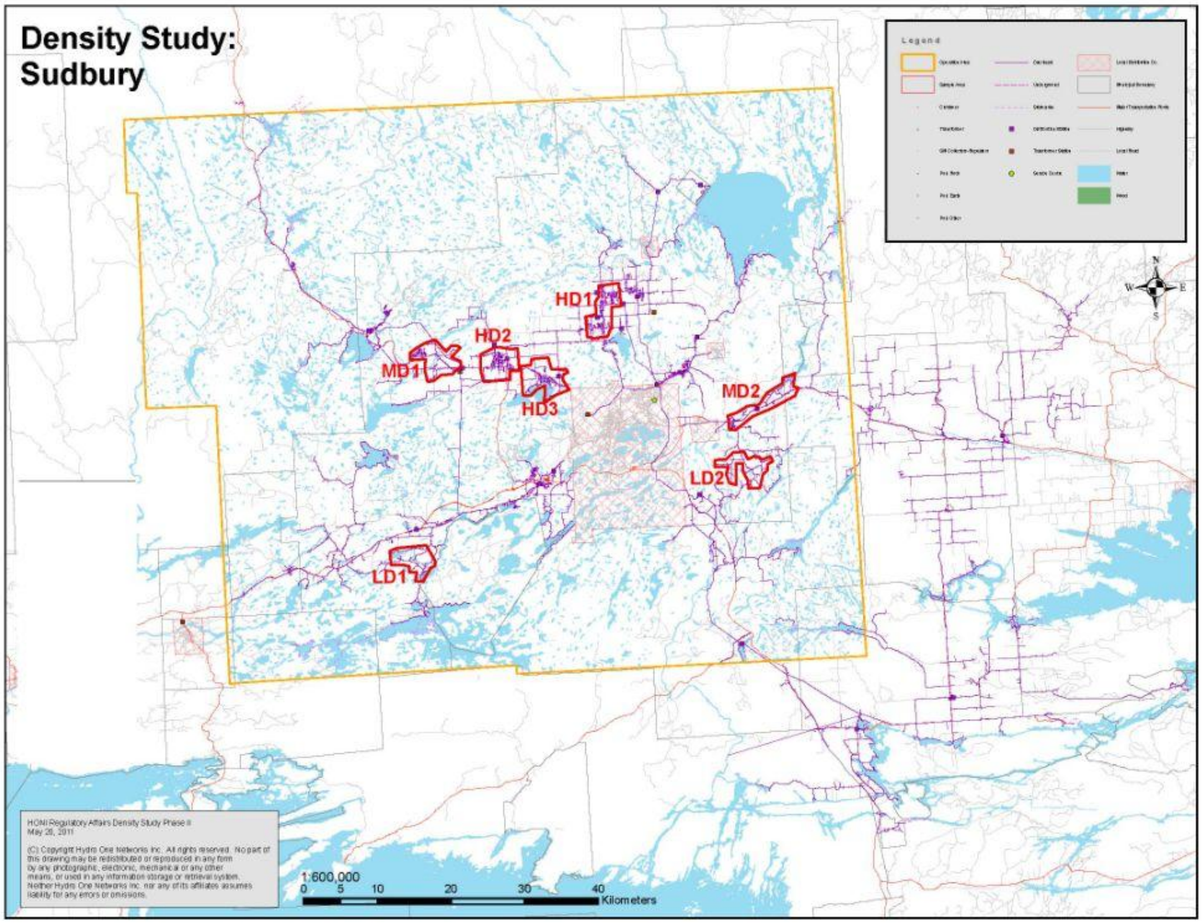
Benjamin Grunfeld/Steven Kim
(416) 643-6610
ben@londoneconomics.com
Mark Vainberg/Gary Ford/Andrew Poray
(416) 487-4175
markvainberg@pnxa.com

Figure 53: Simcoe Operating Area Map



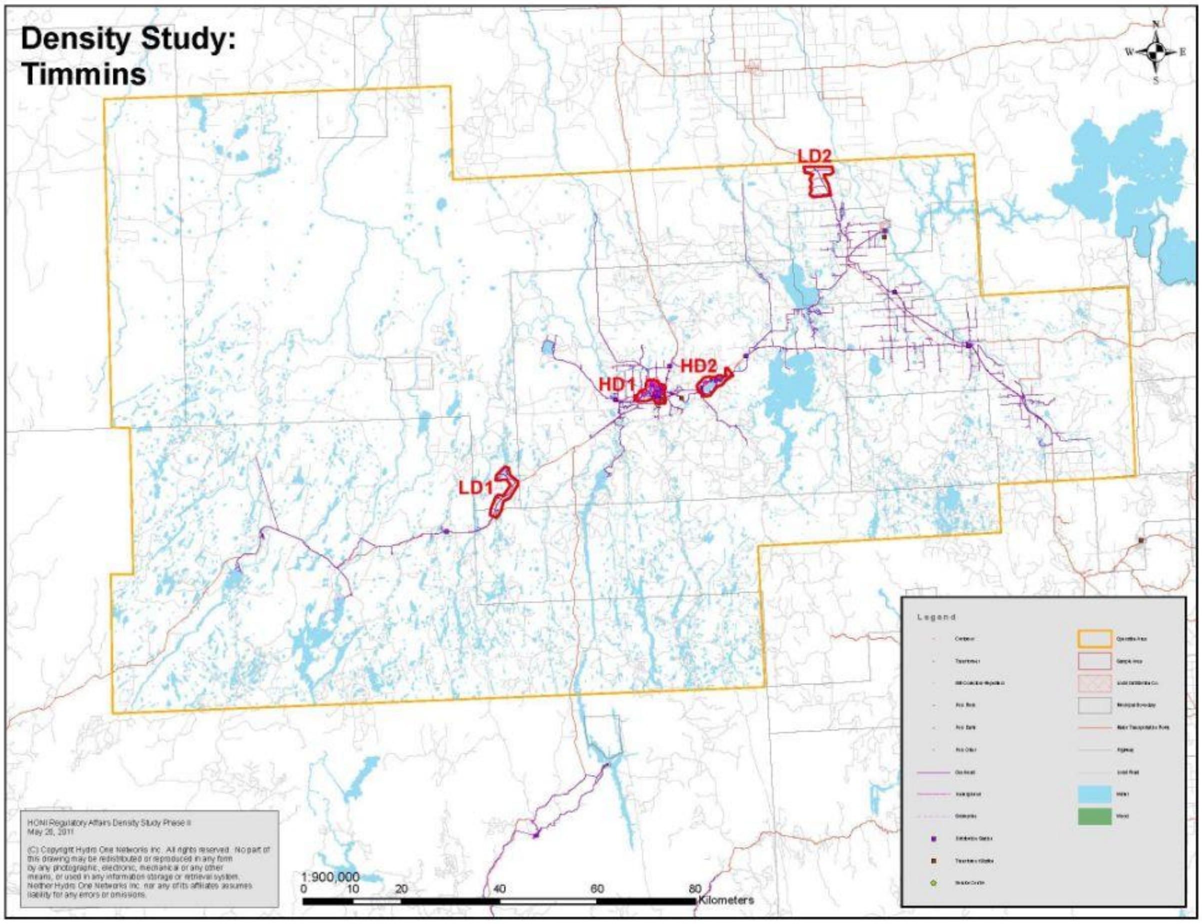
Source: HONI

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

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

Benjamin Grunfeld/Steven Kim
(416) 643-6610
ben@londoneconomics.com
Mark Vainberg/Gary Ford/Andrew Poray
(416) 487-4175
markvainberg@pnxa.com

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

Benjamin Grunfeld/Steven Kim
(416) 643-6610
ben@londoneconomics.com
Mark Vainberg/Gary Ford/Andrew Poray
(416) 487-4175
markvainberg@pnxa.com

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

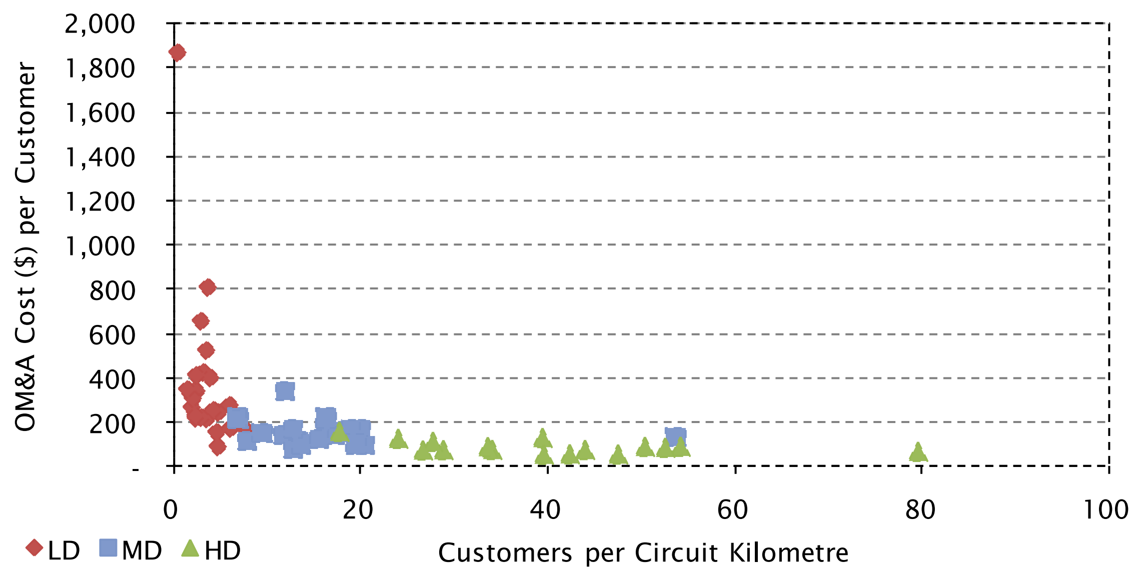
Figure 59: High-Density Sample Area Results

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

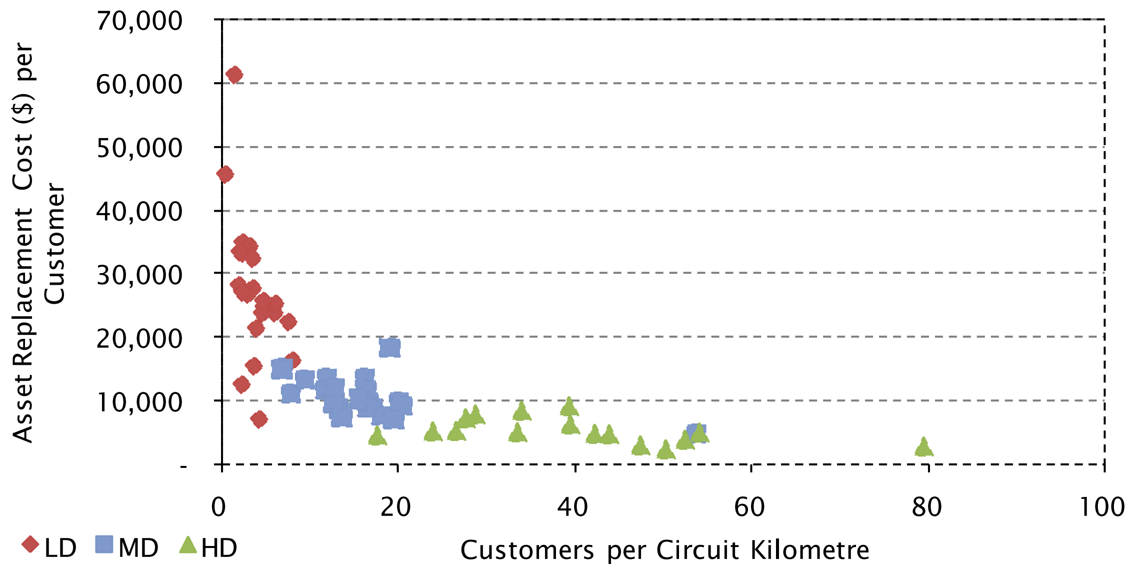
Additional Scatter Plots

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)

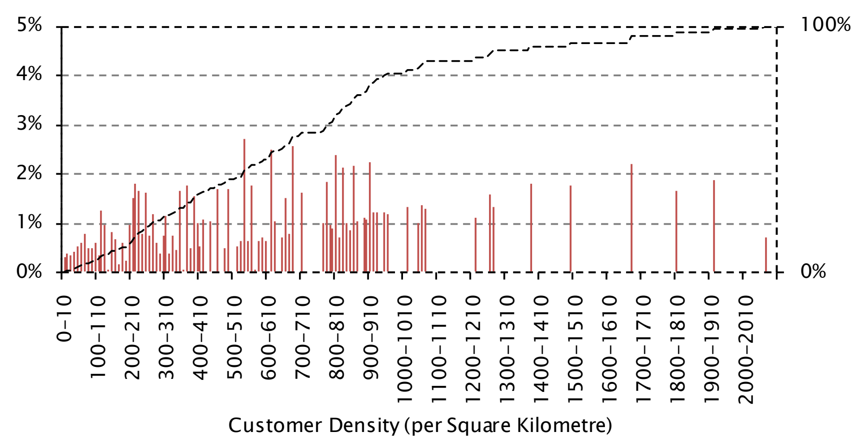


Source: LEI and PNXA analysis

Estimated Density of Existing Rate Classes

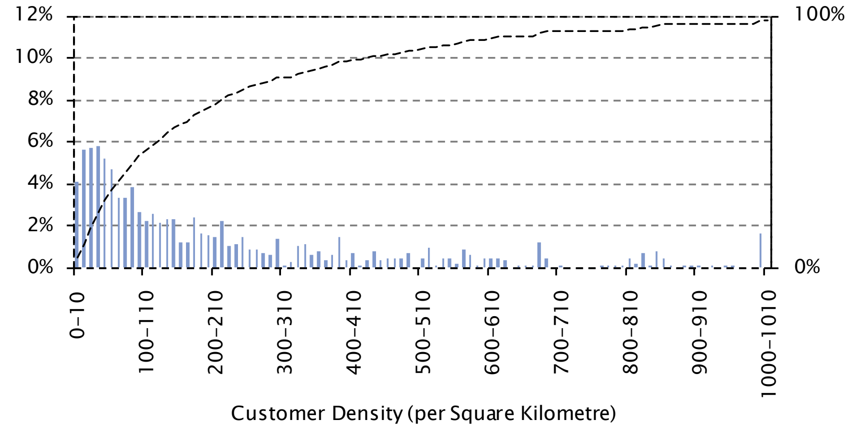
The following figures are based on data provided by HONI from the GIS. A grid consisting of one square kilometre cells was layered over the 11 operating areas included in the direct cost assignment analysis. The number of customers within an individual grid cell is equal to the density of the grid cell. 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



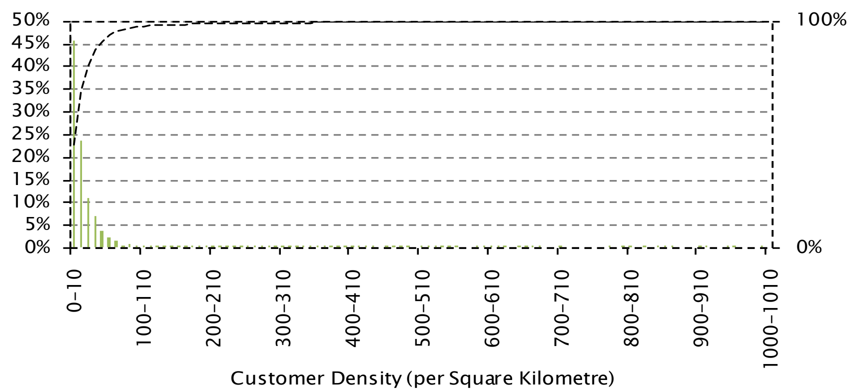
Source: HONI; LEI and PNXA analysis

Figure 63: Customer Density Distribution for HONI's R1 Rate Class in 11 Operating Areas



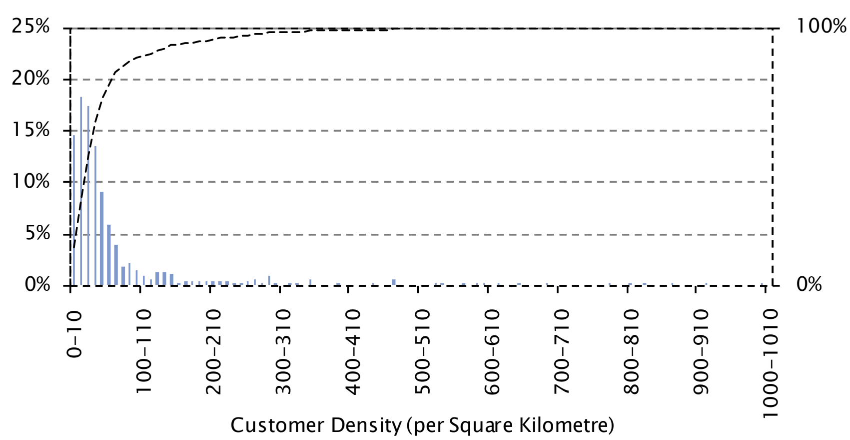
Source: HONI; LEI and PNXA analysis

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

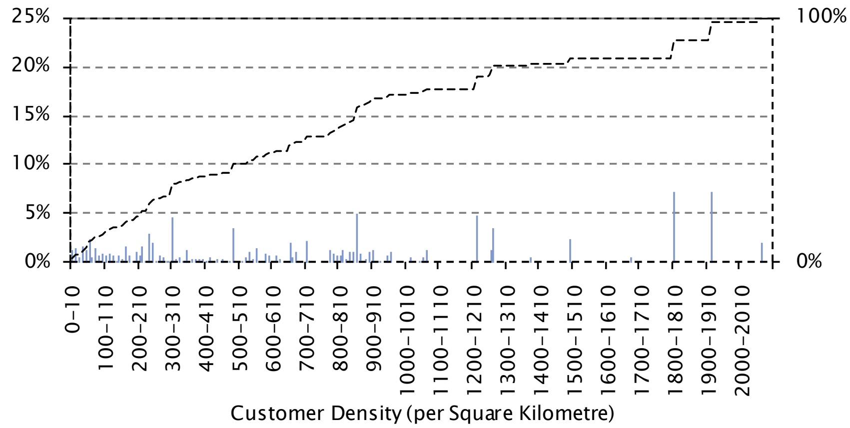


Source: HONI; LEI and PNXA analysis

Benjamin Grunfeld/Steven Kim
(416) 643-6610
ben@londoneconomics.com

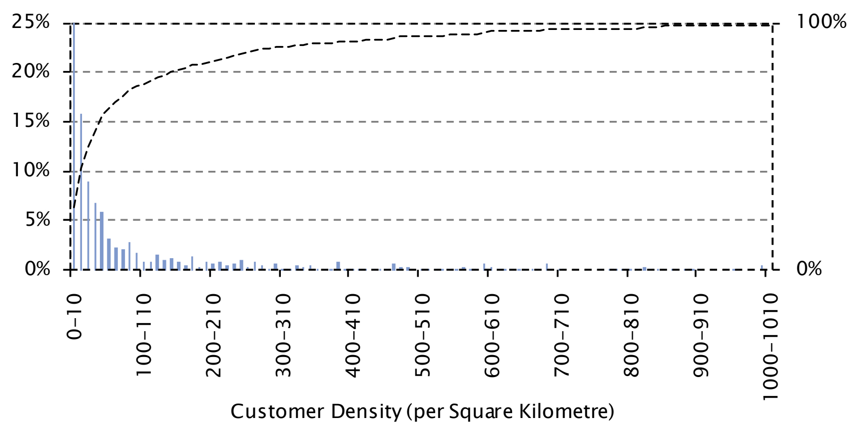
Mark Vainberg/Gary Ford/Andrew Poray
(416) 487-4175
markvainberg@pnxa.com

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

Density Study Adjustment of 2010 Cost Allocation Model Results

		UR	R1	R2	Seasonal		UGe	GSe		UGd	GSd		STR	SEN
Allocated Costs based on Alloc External Revenues	1,180,959,685	58,962,172	273,373,636	431,659,182	96,020,161		8,650,339	121,504,892		12,574,674	128,758,498		9,469,470	7,626,353
CREV + Uniquie Allocation of Misc External Revenues	1,180,959,685	64,525,969	253,761,206	450,022,432	98,554,601		10,440,427	130,123,891		15,692,945	113,370,393		6,454,204	5,073,374
Rev to Cost Ratio -- External Rev CWNB Allocation		1.093	0.928	1.042	1.026		1.200	1.070		1.246	0.881		0.683	0.407
Rev to Cost Ratio -- External Rev Unique Allocation	1.00	1.094	0.928	1.043	1.026		1.207	1.071		1.248	0.880		0.682	0.665

		UR	R1	R2	Seasonal	Total	UGe	GSe	Total	UGd	GSd	Total	STR	SEN
	Total Costs	58,962,172	273,373,636	431,659,182	96,020,161	860,015,150	8,650,339	121,504,892	130,155,232	12,574,674	128,758,498	141,333,173		
	Total Num of Customers	140,540	412,455	367,107	156,901		10,577	98,776		1,130	7,361			
	Unit Cost	$419.54	$662.80	$1,175.84	$611.98		$817.86	$1,230.11		$11,127.61	$17,491.16			
	Ratio relative to urban	1.0	1.6	2.8	1.5		1.0	1.5		1.0	1.6			
	Total Cost ex Cust and A&G	44,718,186	222,971,648	367,439,891	83,971,337	719,101,062	6,699,281	99,898,766	106,598,047	11,103,310	115,420,969	126,524,279		
	Unit Cost	$318.19	$540.60	$1,000.91	$535.19		$633.40	$1,011.37		$9,825.57	$15,679.32			
	Ratio relative to urban	1.0	1.7	3.1	1.7		1.0	1.6		1.0	1.6			
Scenarios		UR	R1	R2	Seasonal	Total	UGe	GSe	Total	UGd	GSd	Total		
IF re-balancing on total cost basis and lowering the R/C ratios to maximum value acceptable by the Board	Cost to be rebalanced	860,015,150					130,155,232			141,333,173				
	Desired cost ratio	1.000	1.700	3.900	1.700		1.0	2.2		1.0	1.7			
	New unit cost	338.57	575.57	1,320.42	575.57		571.15	1,256.53		10,358.50	17,609			
	New allocated funds	47,582,677	237,396,216	484,737,084	90,307,179	860,023,156	6,040,904	124,114,836	130,155,740	11,705,549	129,629,303	141,334,853		
	R/C Ratio	1.36	1.07	0.93	1.09		1.73	1.05		1.34	0.87			
	Target R/C Ratio	1.15		0.95			1.20			1.20	0.91			
	Rev Req	54,720,079		459,828,322			7,249,085			14,046,659	118,208,020			
	Rebalanced Rev Req	-9,805,890		9,805,890			- 3,191,342			- 1,646,286	4,837,627			
	% change	-15.2%		2.2%			-30.6%			-10.5%	4.3%			
IF re-balancing on total costs excluding Cust and A&G and lowering the R/C ratios to maximum value acceptable by the Board	Funds to be rebalanced	719,101,062					106,598,047			126,524,279				
	Desired cost ratio	1.000	1.900	4.800	1.900		1.0	2.6		1.0	1.9			
	New unit cost	240.95	457.81	1,156.56	457.81		398.66	1,036.52		8,370.00	15,903.00			
	New allocated funds	33,863,148	188,823,885	424,581,760	71,829,925	719,098,718	4,216,523	102,382,763	106,599,286	9,458,459	117,067,530	126,525,989		
	Total costs	48,107,134	239,225,873	488,801,051	83,878,749	860,012,806	6,167,581	123,988,890	130,156,471	10,929,823	130,405,059	141,334,882	9,469,470	7,626,353
	R/C Ratio	1.34	1.06	0.92	1.17		1.69	1.05		1.44	0.87		0.71	0.70
	Target R/C Ratio	1.15		0.94	1.15		1.20			1.20	0.91			
	Rev Req	55,323,205		461,319,237	96,460,561		7,401,097			13,115,788	118,468,138		6,744,643	5,301,676
	Rebalanced Rev Req	-9,202,764		11,296,805	-2,094,040		- 3,039,330			- 2,577,157	5,097,745		290,439	228,302
	% change	-14.3%		2.5%	-2.1%		-29.11%			-16.4%	4.5%		4.5%	4.5%
IF re-balancing on total cost basis and lowering the R/C to the previously approved values	Cost to be rebalanced	860,015,150					130,155,232			141,333,173				
	Desired cost ratio	1.000	1.700	3.900	1.700		1.0	2.2		1.0	1.7			
	New unit cost	338.57	575.57	1,320.42	575.57		571.15	1,256.53		10,358.50	17,609			
	New allocated funds	47,582,677	237,396,216	484,737,084	90,307,179	860,023,156	6,040,904	124,114,836	130,155,740	11,705,549	129,629,303	141,334,853		
	R/C Ratio	1.36	1.07	0.93	1.09		1.73	1.05		1.34	0.87			
	Target R/C Ratio	1.09		0.97	1.03		1.21			1.25	0.91			
	Rev Req	52,072,681		468,339,495	92,690,826		7,290,999			14,608,294	117,604,472			
	Rebalanced Rev Req	-12,453,288		18,317,063	-5,863,775		- 3,149,428			- 1,084,651	4,234,079			
	% change	-19.3%		4.1%	-5.9%		-30.2%			-6.9%	3.7%			
IF re-balancing on total costs excluding Cust and A&G and lowering the R/C to the previously approved values	Funds to be rebalanced	719,101,062					106,598,047			126,524,279				
	Desired cost ratio	1.000	1.900	4.800	1.900		1.0	2.6		1.0	1.9			
	New unit cost	240.95	457.81	1,156.56	457.81		398.66	1,036.52		8,370.00	15,903.00			
	New allocated funds	33,863,148	188,823,885	424,581,760	71,829,925	719,098,718	4,216,523	102,382,763	106,599,286	9,458,459	117,067,530	126,525,989		
	Total costs	48,107,134	239,225,873	488,801,051	83,878,749	860,012,806	6,167,581	123,988,890	130,156,471	10,929,823	130,405,059	141,334,882	9,469,470	7,626,353
	R/C Ratio	1.34	1.06	0.92	1.17		1.69	1.05		1.44	0.87		0.72	0.70
	Target R/C Ratio	1.09		0.97	1.03		1.21			1.25	0.91			
	Rev Req	52,646,627		473,007,330	86,092,718		7,443,890			13,640,203	119,186,294		6,784,659	5,332,623
	Rebalanced Rev Req	-11,879,342		22,984,898	-12,461,883		- 2,996,537			- 2,052,742	5,815,901		330,455	259,249
	% change	-18.4%		5.1%	-12.6%		-28.70%			-13.1%	5.1%		5.1%	5.1%

Calculation of New Density Study Adjusted Distribution Rates

2010 Cost Allocation Model Inputs				Current Rates and Charges					
A	B	C	D	E	F	G	H	I	J
Rate Class	Number of Customers	Metered kWh	Metered kW	Current Fixed Charge ($)	Fixed Charge Revenue ($)	Variable Charge Revenue ($)	Current Variable Charge (¢/kWh)	Current Variable Charge ($/kW)	Total Current Revenue ($)
UR	140,540	1,311		14.52	$24,493,479	$38,259,018	2.918		$62,752,497
R1	412,455	4,397		19.72	$97,603,619	$145,840,462	3.317		$243,444,080
R2	367,107	5,375		55.69	$245,325,200	$193,501,563	3.600		$438,826,763
Seasonal	156,901	718		19.71	$37,109,412	$58,933,287	8.205		$96,042,699
GSe	98,776	2,196		35.15	$41,667,398	$86,463,622	3.938		$128,131,020
GSd	7,361	3,122	10,389,644	47.72	$4,215,517	$108,456,724		10.439	$112,672,241
UGe	10,577	364		14.08	$1,787,587	$8,450,647	2.325		$10,238,235
UGd	1,130	600	1,898,173	33.62	$455,852	$15,413,404		8.120	$15,869,256
St Lgt	5,234	122	-	1.05	$65,672	$6,385,815	5.219		$6,451,487
Sen Lgt	37,506	21	-	1.05	$470,596	$1,466,886	6.972		$1,937,483
Dgen	88	4	66,329	37.32	$39,440	$386,202		5.823	$425,642
ST	607	17,938	33,188,720	717.06	$5,222,009	$26,867,863		0.810	$32,089,872
Total	**1,238,282**	**36,169**	**45,542,865**		**$458,455,782**	**$690,425,493**			**$1,148,881,275**

	Density Study Adjustments			Density Study Adjusted Proposed Rates and Charges						
A	K	L	M	N	O	P	Q	R	S	T
Rate Class	Adjustments for New Density-based Rates	Recalculated Total Revenue ($)	Percentage Change in Rates	Recalculated Current Fixed Charge ($)	Recalculated Fixed Charge Revenue ($)	Recalculated Variable Charge Revenue ($)	Recalculated Current Variable Charge ($/kWh)	Recalculated Current Variable Charge ($/kW)	Density Adjusted Proposed 2013 Fixed Charge ($)	Density Adjusted Proposed 2013 Fixed Charge ($/kWh)
UR	-$8,949,830	$53,802,668	-14.3%	12.45	$20,996,698	$32,805,970	0.02502		12.56	0.02524
R1		$243,444,080		19.72	$97,603,312	$145,840,769	0.03317		19.89	0.03346
R2	$10,990,499	$449,817,262	2.5%	57.08	$251,453,900	$198,363,362	0.03691		57.58	0.03723
Seasonal	-$2,040,669	$94,002,030	-2.1%	19.29	$36,319,374	$57,682,656	0.08030		19.46	0.08101
GSe		$128,131,020		35.15	$41,663,659	$86,467,361	0.03938		35.80	0.03973
GSd	$5,209,077	$117,881,318	4.6%	49.93	$4,410,626	$113,470,692		10.922	50.37	11.079
UGe	-$2,980,469	$7,257,765	-29.1%	9.98	$1,266,670	$5,991,095	0.01648		10.07	0.01663
UGd	-$2,606,111	$13,263,145	-16.4%	28.10	$381,050	$12,882,094		6.787	28.35	6.9
St Lgt	$290,317	$6,741,804	4.5%	1.09	$68,461	$6,673,343	0.05454		1.10	0.05502
Sen Lgt	$87,187	$2,024,670	4.5%	1.09	$490,578	$1,534,091	0.07291		1.10	0.07355
Dgen		$425,642		37.32	$39,442	$386,199		5.823	37.65	5.928
ST		$32,089,872		717.06	$5,222,041	$26,867,830		0.810	723.37	0.871
Total		**$1,148,881,275**			**$459,915,812**	**$688,965,463**				