London Hydro

File Number: EB-2016-0091

Date Filed: August 26, 2016

EXHIBIT 9 -
DEFERRAL AND VARIANCE ACCOUNTS

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Exhibit 9

Tab 1 of 1

DEFERRAL AND VARIANCE ACCOUNTS

INTRODUCTION

London Hydro currently has existing Board-approved Rate Riders for the disposition of Group 1 deferral and variance account (DVA) balances (audited December 2014 principal balances and carrying charges to April 30, 2016), set out in the Board's Decision in London Hydro's 2016 IRM Application (EB-2015-0087) for the period of May 1, 2016 to April 30, 2017.

London Hydro has included in this Application a request for disposition of audited Group 1 and Group 2 DVA balances, including Renewable Generation Connection and Smart Grid Development Deferral Accounts, at December 31, 2015 and the forecasted interest to April 30, 2017. The costs of initiatives recorded in the Renewable Generation Connection and Smart Grid Development Deferral Accounts are presented under title *Climate Change Projects* in this application.

London Hydro is requesting disposition of the DVA balances, including interest, over a one-year refund period commencing May 1, 2017 through proposed rate riders.

The forecasted interest on December 31, 2015 principal balances of the DVA balances is calculated using the Board's prescribed rate of 1.10% for the period of January 1, 2016 to April 30, 2017.

This schedule contains descriptions of the DVAs for which London Hydro is requesting disposal through Deferral and Variance Account Rate Riders. These accounts are detailed in Table 9-8 – Deferral and Variance Accounts Submitted for Recovery with this Application.

London Hydro is not requesting recovery of the Deferral and Variance Accounts previously approved for recovery with disposition period that had not expired as of December 31, 2015 as part of this Application.

In accordance with the guidance and directions that have been provided by the Board to date, London Hydro is requesting the recovery of the residual balance of the 1555 Sub-account Stranded Meter Costs with this Application.

In accordance with the guidance and directions that have been provided by the Board to date, London Hydro is requesting new DVAs in this Application.

London Hydro confirms that it had not made any adjustment to deferral and variance account balances that were previously approved by the OEB on a final basis in both Cost of Service and IRM proceedings.

London Hydro used the OEB's Deferral and Variance Account (Continuity Schedule) Work Form – Version 2.8 (2017 EDDVAR Continuity Schedule), updated on July 21, 2016, and an ED Capital OMA Disposal Generator to calculate the proposed rate riders.

London Hydro used the Board prescribed interest rates for the respective quarterly period to calculate the carrying charges for each regulatory deferral and variance accounts:

Table 9-1 – Quarterly Board Approved Prescribed Interest Rates for Deferral and Variance Accounts used in calculation of carrying charges:

Quarter	Interest Rate	Quarter	Interest Rate
2009 QTR 1	2.45%	2013 QTR 1	1.47%
2009 QTR 2	1.00%	2013 QTR 2	1.47%
2009 QTR 3	0.55%	2013 QTR 3	1.47%
2009 QTR 4	0.55%	2013 QTR 4	1.47%
2010 QTR 1	0.55%	2014 QTR 1	1.47%
2010 QTR 2	0.55%	2014 QTR 2	1.47%
2010 QTR 3	0.89%	2014 QTR 3	1.47%
2010 QTR 4	1.20%	2014 QTR 4	1.47%
2011 QTR 1	1.47%	2015 QTR 1	1.47%
2011 QTR 2	1.47%	2015 QTR 2	1.10%
2011 QTR 3	1.47%	2015 QTR 3	1.10%
2011 QTR 4	1.47%	2015 QTR 4	1.10%
2012 QTR 1	1.47%	2016 QTR 1	1.10%
2012 QTR 2	1.47%	2016 QTR 2	1.10%
2012 QTR 3	1.47%	2016 QTR 3	1.10%
2012 QTR 4	1.47%	2016 QTR 4	1.10%
2013 QTR 1	1.47%	2017 QTR 1	1.10%
2013 QTR 2	1.47%	2017 QTR 2	1.10%

DEFERRAL AND VARIANCE ACCOUNT BALANCES

The following Table 9-2 – Outstanding Deferral and Variance Accounts lists the outstanding DVAs and sub-accounts with audited balances documented in London Hydro's Audited Financial Statements and reported pursuant to section 2.1.7 of the Board's Reporting and Record-keeping Requirements (Trial Balance) as at December 31, 2015. The accounts are grouped according to the sections within which they are described in this Exhibit.

Table 9-2 – Outstanding Deferral and Variance Accounts

Outstanding Deferral and Variance Accounts		2.1.7 RRR Balances at Dec 31, 2015	Continuity Schedule 2015 Closing Balance	Difference
Group 1 Accounts				
1551	Smart Metering Entity Charge Variance Account	$ 59,014	$ 59,014	$ -
1580	RSVA - Wholesale Market Service Charge	$ (14,744,290)	$ (14,744,290)	$ -
1580	Variance WMS – Sub-account CBR Class A	$ 46,205	$ 46,205	$ -
1580	Variance WMS – Sub-account CBR Class B	$ 819,279	$ 819,279	$ -
1584	RSVA - Retail Transmission Network Charge	$ 2,159,540	$ 2,159,540	$ -
1586	RSVA - Retail Transmission Connection Charge	$ 979,113	$ 979,113	$ -
1588	RSVA - Power	$ (829,934)	$ (829,934)	$ -
1589	RSVA - Global Adjustment	$ 9,266,120	$ 8,500,006	$ 766,114
1595	Disposition and Recovery/Refund of Regulatory Balances (2012)	$ (298,342)	$ (298,342)	$ -
1595	Disposition and Recovery/Refund of Regulatory Balances (2013)	$ (38,093)	$ (38,093)	$ -
1595	Disposition and Recovery/Refund of Regulatory Balances (2014)	$ 4,801	$ 4,801	$ -
Total Group 1 Accounts - Subtotal		**$ (2,576,587)**	**$ (3,342,701)**	**$ 766,114**
Group 2 Accounts				
1508	Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	$ 26,284	$ 26,284	$ -
1518	Retail Cost Variance Account - Retail	$ 87,894	$ 87,894	$ -
1548	RCVASTR	$ (160)	$ (160)	$ -
1555	Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs	$ 30,438	$ 30,482	$ (44)
1575	IFRS-CGAAP Transitional PP&E Amounts	$ 157,307		$ 157,307
1568	LRAM Variance Account	$ 1,215,463	$ 442,959	$ 772,504
1592	PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	$ (160,969)	$ (160,969)	$ -
Total Group 2 Accounts - Subtotal		**$ 1,356,258**	**$ 426,490**	**$ 929,767**
Renewable Generation Connection and Smart Grid Development Deferral Accounts - Climate Change Projects				
1531	Renewable Generation Connection Capital Deferral Account	7,848	$ -	7,848
1532	Renewable Generation Connection OM&A Deferral Account	148,311	$ -	148,311
1534	Smart Grid Capital Deferral Account	325,830	$ -	325,830
1535	Smart Grid OM&A Deferral Account	389,073	$ -	389,073
Total Group 2 Accounts - Subtotal		**871,061**	**$ -**	**871,061**
		$ (349,268)	**$ (2,916,210)**	**$ 2,566,942**

Differences between balances reported in E2.1.7 Trial Balance and balances included in the 2017 EDDVAR Continuity Schedule are as follows:

ACCOUNT 1589 RSVA - GLOBAL ADJUSTMENT

The balance in Account 1589 RSVA - Global Adjustment has not been adjusted. The difference in the 2017 EDDVAR Continuity Schedule for the account is the summary of the year-to-date Global Adjustment variance for the existing and new class A customers. These balances are not included in the 2017 EDDVAR Continuity Schedule for rate rider calculation purposes. Although the amounts related to this component are not adjustments, simply the removal from the Class B disposition value, they are reflected in the "adjustment" column in the Continuity Schedule tab in each year for easy identification.

RSVA Class A GA	Principal	Interest	YTD Total
Class A	1,205	(338)	867
New Class A	751,969	13,279	765,247
YTD Balance at December 31, 2015	**753,173**	**12,941**	**766,114**

- Class A customers pay the actual Global Adjustment, and the variance is due to minor rounding differences in amounts invoiced by the IESO, based on the Peak Demand Factor (PDF) assigned to London Hydro and what was billed to the customers using the customer specific PDF factor. This balance is insignificant and has not been submitted for disposition with this rate application.

- The RSVA GA variances for the new Class A customers are subject to direct settlement. The six new Class A customers are easily identifiable and the RSVA GA balances are maintained separately in a work sheet. Direct settlement amounts are calculated for each new Class A customer outside of the 2017 EDDVAR Continuity Schedule Work Form, and submitted separately for disposition.

ACCOUNT 1555 SMART METER CAPITAL AND RECOVERY OFFSET VARIANCE - SUB-ACCOUNT - STRANDED METER COSTS

The difference in Account 1555 Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs results from interest adjustment.

London Hydro made a $44 adjustment in Year 2016 to interest earned after May 1, 2013 because the interest recoveries were originally recorded as principal recoveries. After the recoveries were applied properly within each rate class, a small adjustment to interest calculations was required.

A detailed explanation of the adjustment is provided under the account description of 1555 Smart Meter Capital and Recovery Offset Variance Account, Sub-account Stranded Meter Costs within this Exhibit.

ACCOUNT 1575 IFRS-CGAAP TRANSITIONAL PP&E AMOUNTS

The Account 1575 IFRS-CGAAP Transitional PP&E Amount is not included in the 2017 DVA Continuity Schedule model as it was previously approved for recovery in the disposition period that had not expired as of December 31, 2015.

ACCOUNT 1568 LRAMVA

Adjustments were made to the December 31, 2015 balance of Account 1568 LRAMVA to:

- accommodate the most recent Guideline, Report of the OEB: Updated Policy for the Lost Revenue Adjustment Mechanism Calculation: Lost Revenues and Peak Demand Savings from Conservation and Demand Management Programs (EB-2016-0182 – the “LRAMVA Report”), issued on May 19, 2016;

- update the LRAMVA calculations for years 2013 to 2015 based on the methodology employed in the OEB model Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) Work Form – Version 1.0 (2017), issued on July 8, 2016, updated on August 4, 2016; and

- update the 2015 estimated values to the actual values of energy and demand savings based on the Final 2015 Annual Verified Results Report.

Detailed explanations of the adjustments are provided under the account description of 1568 LRAMVA within this Exhibit.

RENEWABLE GENERATION CONNECTION AND SMART GRID DEVELOPMENT DEFERRAL ACCOUNTS – CLIMATE CHANGE PROJECTS

Accounts listed under Climate Change Projects (1531, 1532, 1534, 1535) have been excluded from the 2017 EDDVAR Continuity Schedule. London Hydro used an ED Capital OM&A Disposal Generator model to complete the calculations for the disposition of the deferral accounts in this group.

GROUP 1 DEFERRAL AND VARIANCE ACCOUNTS

1551 SMART METERING ENTITY CHARGE VARIANCE ACCOUNT

This account is used to record the variances arising from the Smart Metering Entity charges paid to the IESO and billed to Residential and General Services <50 kW customers.

1580 RETAIL SETTLEMENT VARIANCE ACCOUNT - WHOLESALE MARKET SERVICE CHARGES

This account is used to record the net of the amounts charged by the Independent Electricity System Operator (IESO) based on the settlement invoice for the operation of the IESO-administered markets and the operation of the IESO-controlled grid and the amount charged by Hydro One Networks Inc. as host distributor, and the amount billed to customers using the Board-Approved Wholesale Market Service Rate.

1580 RETAIL SETTLEMENT VARIANCE ACCOUNT - WHOLESALE MARKET SERVICE CHARGES – SUB-ACCOUNT CAPACITY BASED RECOVERY CLASS A

This account is used to record the net of the amounts charged by the Independent Electricity System Operator (IESO) on the settlement invoice under Charge Type 1350 for Capacity Based Recovery (CBR) for Class A Loads, and the allocated amount, calculated using the customer specific Class A PDF, billed to customers. The allocation of CBR recovery is calculated in the same manner as the global adjustment, where cost recovery is related to the contribution of various consumers to peak-capacity resources.

1580 RETAIL SETTLEMENT VARIANCE ACCOUNT - WHOLESALE MARKET SERVICE CHARGES – SUB-ACCOUNT CAPACITY BASED RECOVERY CLASS B

This account is used to record the net of the amounts charged by the Independent Electricity System Operator (IESO) on the settlement invoice under Charge Type 1351 for CBR for Class B Loads and the amount billed to customers using the $0.0004/kWh included in the Board-

Approved Wholesale Market Service (WMS) Rate. Variances accumulated during Year 2015 consist of amounts charged by the IESO as there was no CBR component included in the WMS rate.

1584 RETAIL SETTLEMENT VARIANCE ACCOUNT – RETAIL TRANSMISSION NETWORK

This account is used to record the net of the amounts charged by the IESO based on the settlement invoice for transmission network services and the amount billed to customers for the same services using the Board-Approved Transmission Network Charge Rate.

1586 RETAIL SETTLEMENT VARIANCE ACCOUNT – RETAIL TRANSMISSION CONNECTION

This account is used to record the net of the amounts charged by the IESO based on the settlement invoice for transmission connection services and the amount billed to customers for the same services using the Board-Approved Transmission Connection Charge Rate.

1588 RETAIL SETTLEMENT VARIANCE ACCOUNT – POWER

This account is used to record the net of the amounts charged by the IESO, based on the settlement invoice for energy, and embedded generators, and the energy amounts billed to customers.

1589 RETAIL SETTLEMENT VARIANCE ACCOUNT – GLOBAL ADJUSTMENT

This account is used to record the net of the global adjustment charge for non-Regulated Price Plan customers by the IESO, based on the settlement invoice, and the global adjustment amounts billed to non-Regulated Price Plan customers.

London Hydro confirms that it pro-rates the IESO Global Adjustment Charge into RPP and non-RPP portions.

London Hydro served three (3) Class A customers during January 1, 2015 to June 30, 2015, with a combined peak demand factor of 0.00112335, of which one (1) customer ceased operations as of June 30, 2015. For the period of July 1, 2015 to December 31, 2015, eight Class A customers were served, with a combined peak demand factor of 0.00141903, of which six are "new Class A" customers.

Adjustment Period	Number of Class A Customers	Combined Peak Demand Factor
July 1, 2015 - June 30, 2016	8	0.00141903
July 1, 2014 - June 30, 2015	3	0.00112335

THE IESO SETTLEMENT PROCESS

As a new addition for 2016, Chapter 2 of the Board's Filing Requirements for Electricity Distribution Rate Applications, dated July 16, 2015, distributors must provide a description of their settlement process with the IESO. Distributors must specify the GA rate used when billing customers for each rate class, itemize the process for providing consumption estimates to the IESO, and describe the true-up process to reconcile estimates of RPP and non-RPP consumption once actuals are known.

Settlement Process Overview

The IESO Form 1598 is calculated monthly and submitted to determine the receivable/payable amount from/to the IESO. London Hydro dollar inputs are used for determination and settlement of the Regulated Price Plan Settlement Amount (charge type 142), Renewable Energy Standard Offer Program Settlement Amount (charge type 1410), Feed-In Tariff Program Settlement Amount (charge type 1412), and Ontario Clean Energy Benefit (-10%) Program Settlement Amount (charge type 9992).

In addition, London Hydro includes various types of consumption and customer count information for the IESO to use for verification of claims, estimation of charges (e.g., Smart Metering Charge (charge type 9980)) and forecasting purposes.

Regulated Price Plan Settlement Amount

London Hydro Inc. (London Hydro) utilizes the IESO Form 1598 to claim the difference between Regulated Price Plan (RPP) rates applied to regulated rate plan consumers, and the sum of the corresponding consumption multiplied by the weighted average of the Hourly Ontario Energy Price (HOEP) and Global Adjustment (GA). The process is completed by the fourth business day of the month using meter data available from London Hydro's settlement systems.

London Hydro's uses its SAP system for billing customers monthly. Normally customers are billed in levelized billing cycles with established from and to dates to balance the daily bill print process. Predominantly large use customers and manually generated reads (co-gen, street light, unmetered scattered load etc.) are billed based on whole month billings.

The following section discusses the steps taken to calculate the Regulated Price Plan Settlement Amount:

i. Determination of current low volume consumption at RPP rates:

For the current IESO billing month, London Hydro extracts from the SAP system the total billed consumption and RPP applied rate amount for all RPP customers. Low volume consumption is extracted between RPP customers on tiered pricing and on TOU pricing.

ii. Determination of current low volume consumption at the weighted average HOEP:

London Hydro maintains a table of the weighted average HOEP that is used to calculate and be applied to the extracted consumption of each recorded transaction in i) above. The final amount calculated is subtracted from i) above.

iii. Determination of current low volume consumption at the average GA:

London Hydro maintains two tables (tiered and TOU RPP) to determine the average monthly proportions of RPP consumption against total wholesale consumption and the divisions between the RPP rates applied. The values maintained in these tables are the prorated actuals determined from transactions two months prior to current as determined in iv) below. These proportions and splits are used to calculate and be applied to the current month's wholesale consumption against the current months 2nd estimate global adjustment. The final amount calculated is subtracted from i) above.

iv. True-up of low volume consumption GA from two months prior:

London Hydro extracts from the SAP system the line by line prorated billed consumption by rate amount for all billed RPP customers for the period two months prior to current. The resultant quantity is multiplied by the Actual GA rate from two months prior. The resultant amount is reconciled against the amount calculated in iii) above two months prior. The reconciled amount is applied against the product of i), ii) and iii) above.

v. RPP – Final Variance Settlement Amount:

London Hydro extracts from the SAP system the Final Variance Settlement Amounts billed to customers who have declared they are leaving the system. This amount is subtracted against the product of i), ii), iii), and iv) above.

Renewable Energy Standard Offer Program (RESOP) Settlement Amount

London Hydro extracts from the SAP system the actual credit amounts calculated and remitted during the current month to RESOP customers per IESO contract agreements.

Feed-In Tariff (FIT) Program Settlement Amount

London Hydro extracts from the SAP system the actual credit amounts calculated and remitted during the current month to FIT and microFIT customers per IESO contract agreements.

Ontario Clean Energy Benefit (-10%) Program Settlement Amount

London Hydro extracts from the SAP system the actual 10% credit amounts calculated and applied during the current month to low volume consumption customers per legislation.

Other information

London Hydro relies on accrual accounting and currently bills all Class B customers using the IESO's Global Adjustment first estimate rate and all Class A customers using the actual Global Adjustment rate.

The IESO recently established a self-certification program designed to enhance the consistency of the 1598 claims process and the level of assurance provided by LDCs regarding the calculation and recording of claims. London Hydro submitted its first self-certification on May 31, 2015 for the 2014 fiscal year end.

Class A Customers

As of July 1, 2015, per O. Reg 429/04, an eligible customer with a maximum hourly demand over three megawatts, but less than five megawatts, can elect to become a Class A customer for an applicable adjustment period of one year. Chapter 2 of the Board's Filing Requirements for Electricity Distribution Rate Applications requires the distributor to report the number of Class A customers it served in 2014 and 2015, as well as their combined peak demand factor for each period.

London Hydro followed the Board's Accounting Procedures Handbook and other Board-issued guidance to record the variances in the RSVA accounts. The RSVA amounts requested for disposition are the variances accumulated during Year 2015.

The Board approved the disposition of the audited December 31, 2014 RSVA balances with the 2016 IRM Application over a one-year period (EB-2015-0087). This disposition is reflected in the 2017 EDDVAR Continuity Schedule.

1595 DISPOSITION AND RECOVERY/REFUND OF REGULATORY BALANCES

This account is used to record the disposition of deferral and variance account balances for which electricity distributors received approval to recover (or refund) account balances in rates. The sub-account is used to record the approved principal account balances on the transfer to Account 1595 of the Board-approved deferral or variance account balances. It also includes the amounts recovered (or refunded) in rates through regulatory asset or deferral and variance accounts rate rider. The sub-account is used to record the cumulative carrying charge account balances on the transfer to Account 1595 of the Board-approved deferral or variance account balances, and another sub-account is used to record the carrying charges calculated on the opening monthly net principal balance using the rate prescribed by the Board.

GROUP TWO DEFERRAL AND VARIANCE ACCOUNTS

IDENTIFICATION OF GROUP TWO DEFERRAL AND VARIANCE ACCOUNTS

Outstanding Group 2 and Other Deferral and Variance Accounts		Continue / Discountinue	Explanation
1508	Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	Discountinue	Upon disposition no longer required
1518	Retail Cost Variance Account - Retail	Continue	Continue to utilize according to the Accounting Procedures Handbook ("APH")
1548	RCVASTR	Continue	Continue to utilize according to APH
1555	Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs	Discountinue	Upon disposition no longer required
1568	LRAM Variance Account	Continue	Continue to utilize according to APH
1575	IFRS-CGAAP Transitional PP&E Amounts	Discountinue	Upon disposition no longer required
1592	PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	Discountinue	Upon disposition no longer required
Climate Change Projects Deferral and Variance Accounts			
1531	Renewable Generation Connection Capital Deferral Account	Discountinue	Upon disposition no longer required
1532	Renewable Generation Connection OM&A Deferral Account	Discountinue	Upon disposition no longer required
1534	Smart Grid Capital Deferral Account	Discountinue	Upon disposition no longer required
1535	Smart Grid OM&A Deferral Account	Discountinue	Upon disposition no longer required

1508 OTHER REGULATORY ASSETS
SUB-ACCOUNT - DEFERRED IFRS TRANSITION COSTS

This account is used to record incremental one-time costs associated with the transition to IFRS during the period March 2009 to December 2015 in excess of amounts previously included in rates, as addressed and established by the Board in the Report to the Board regarding Transition to International Financial Reporting Standards (EB-2008-0408). Costs incurred up to December 31, 2011 have been submitted and approved for recovery, including carrying charges, with the 2013 Cost of Service application (EB-2012-0146). The 2013 Cost of Service rate application also included a request that this account continue until such time as transition to IFRS is complete.

London Hydro is requesting a disposition of costs in this account up until its last audited year, ended on December 31, 2015.

The transition to IFRS is now completed and, therefore, London Hydro proposes the discontinuation of this deferral account after its disposition on May 1, 2017.

London Hydro confirms that there is no one-time administrative incremental IFRS transition cost embedded in the proposed 2017 revenue requirement.

IFRS Implementation Project

On February 13, 2008, the Canadian Accounting Standards Board (AcSB) officially confirmed the requirement for publicly accountable enterprises to adopt IFRS for financial reporting purposes.

To take on the responsibilities and numerous tasks associated with moving to a new accounting standard, London Hydro assembled a team of employees from the Finance, Regulatory, Engineering and Operations departments and engaged consulting services for matters associated with information technology, external audit, the employee future benefits liability and the useful lives of property, plant and equipment.

Many factors had to be considered when moving to a new accounting standard, such as

- **Accounting and Reporting:** accommodating reporting under IFRS, MIFRS and dual reporting under both CGAAP and IFRS in the transitional year
- **Systems and Processes:** assessing the current system and arranging for any required modifications
- **Business:** educating stakeholders, bankers and other readers of results on the impact of IFRS in a rate regulated environment
- **Employee Training:** establishing new procedures and associated employee training to gather new required information

Each of these factors needed to be reviewed and required extensive research and decision making:

Accounting and Reporting

- **First time adoption of IFRS:** considered and implemented mandatory and elective exemptions and prepared the opening balance sheet at the transition date and provide for IFRS 1 disclosure in the financial statements

- **Inventory:** reviewed IFRS differences with respect to the treatment of major spare parts and standby equipment for items that should be reclassified to fixed assets

- **Property Plant and Equipment:** investigated the major differences between IFRS and CGAAP with respect to fixed assets and assess the required treatment for:

    - ***Component accounting***: segregated significant components and assessed any required changes with respect to major overhauls and inspection

    - ***Depreciation***: assessed and implemented new life spans on the new components

    - ***Derecognition***: developed procedures to remove the carrying amount of assets removed from the infrastructure

    - ***Borrowing costs***: reviewed IFRS requirements in connection with the capitalization of general and specific interest costs on qualifying projects

    - ***Transfer of assets from customers***: reviewed accounting and system changes required to treat capital contributions as deferred revenue to be amortized as revenue giving further consideration to the dual mapping required for the alternative presentation required under MIFRS

    - ***Decommissioning liabilities***: reviewed any liabilities to be accrued in connection with legal or construction obligations related to asset retirement

- *Impairments*: reviewed and implemented changes to accommodate any new IFRS requirements with respect to testing for and reporting of tangible and intangible asset impairments
- *Overhead costs:* reviewed all capitalized overhead costs to remove those items considered general and administrative in nature and to ensure that only directly attributable costs are included

- **Capitalization policy and procedures**: assessed required changes regarding capital versus expense by identifying those expenditures that are considered directly attributable to bring an asset to the location of working condition for its intended use and developed a formalized written policy to document the new policy and procedures required to comply with IFRS requirements
- **Segregation of intangible assets**: identified and reclassified those assets that are considered intangible in nature, such as systems software and land rights, and provide for separate disclosure
- **Employee benefits**: reviewed, selected and implemented elections available with respect to the recognition of actuarial gains and losses
- **Revenue recognition**: reviewed IFRS standards for any required changes in the recognition of revenues
- **Income taxes**: reviewed transition from current taxes to deferred taxes in the statement of profit and loss and remove the regulatory liability associated with the future tax asset and assessed and accommodated the treatment of regulatory assets and liabilities for income tax reporting purposes
- **Operating and capital leases**: reviewed IFRS standards with respect to the classification of leases between finance (capital) and operating
- **Related party transactions**: assessed new IFRS requirements with respect to the definition and disclosure of related party transactions and new information that needs to

be assembled to accommodate reporting of Key Management Personnel compensation and employee benefits

- **Provisions, contingent liabilities and contingent assets**: reviewed and accommodated for the differences between CGAAP and IFRS with respect to provisions and legal and constructive obligations to be recognized

- **Financial statement disclosure**: reviewed the items that require disclosure under IFRS and the information necessary to accommodate them

- **Regulatory accounting**: considered the complexities associated with reporting on regulatory amounts as a profit and loss activity under IFRS, while at the same time reporting these same amounts as a balance sheet activity under MIFRS and implemented the required dual procedures and transactions needed to accommodate both of these reporting necessities

Systems and Processes

- **Dual ledgers**: assessed and modified the J.D. Edwards accounting system to run dual ledgers in both the general ledger and the fixed assets module, as required to accommodate the reporting of transactions in the transitional years under both CGAAP and IFRS

- **Unbundling of fixed asset additions**: made system and procedural modifications required to record fixed asset additions in greater detail when capitalizing capital projects from work-in-progress, without incurring additional costs associated with the purchase and implementation of a job costing module

- **GIS system modifications**: reviewed and modified the Geographic Information System to gather data and issue reporting with respect to assets removed from the infrastructure, which is essential in identifying capital assets to be derecognized as required under IFRS

Business

- **Rate-regulated accounting uncertainties**: placed issues on hold pending decisions from the AcSB and the Ontario Energy Board

- **Educating financial statement readers**: prepared education and additional reporting to assist readers of financial statements in understanding the differences between CGAAP and IFRS and the implications of reporting regulatory activities through the statement of profit and loss

- **Budgeting:** modified the budgeting process to align with reporting under IFRS and preparing budgets under CGAAP, IFRS and MIFRS

Employee Training

- **New processes:** developed and implemented new processes to capture data and record transactions in the detail and structure required to meet new information needs

- **Employee training**: trained employees on the new information needs and resulting new processes

- **Documentation**: developed employee reference documentation, as well as forms and templates to gather new information

IFRS Transition Incremental Costs

Incremental one-time administrative costs incurred as a result of the transition to IFRS through the year ended December 31, 2011, which have accumulated to $355,673, have been submitted and approved for recovery, including carrying charges, with the 2013 Cost of Service application (EB-2012-0146).

Incremental one-time administrative costs incurred as a result of transition to IFRS, through years 2012 to 2015, have accumulated to $26,643 and consist mainly of incremental professional and consulting services.

For greater clarity, please be advised that this account does not contain any capital costs or costs that are ongoing or non-incremental in nature. In addition, none of the above-noted amounts relate to changes in accounting policies as a result of the move to IFRS.

Amounts included in rates as per the above table relate to London Hydro's Cost of Service in 2009 and are detailed in section titled *IFRS Implementation Costs included in Current Rates* of this Exhibit.

Summary of IFRS expenditures		Year-to date Costs at December 31, 2011 RECOVERED	Costs in Years 2012-2015
Incremental laobur and benefits		$ 169,095	
Professional and consulting services:			
KPMG - IFRS compliance consulting and training	107,062		33,090
Kinectrics - study on the useful lives of property, plant, equipment and intangibles	23,000		
Syntax - assessment and modification for J.D. Edwards accounting system	104,454		
Mercer - actuarial review of employee future benefits liability	15,000	249,516	17,450
Course tuitions and subscriptions		5,412	
Subtotal		424,023	50,540
Add: Carrying charges		6,650	1,103
Less: Amount included in previous rates		(75,000)	(25,000)
Transitional costs claimed with cost of service application		**355,673**	**26,643**
Costs approved for recovery with 2013 COS (EB-2012-0146)		**(355,673)**	
Balance of Account 1508 Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs		**-**	**26,643**

Pursuant to the Board's Filing Requirements issued July 14, 2016, a schedule of One-Time Incremental IFRS Transition Costs (OEB Appendix 2-YA) for spending during years 2012 to 2015 is provided in Appendix 9B of this Exhibit.

- **IFRS compliance consulting and training**: KPMG consulting services was engaged to assist in the conversion to IFRS, to help ensure that all IFRS requirements are being met to augment financial statement and disclosure development, and to provide training.

- **Actuarial review of employee future benefits liability**: Mercer actuarial services were hired to review London Hydro's employee future benefits liability in accordance with IFRS IAS19.

IFRS Implementation Costs Included in Current Rates

London Hydro's rebasing in 2009 (EB-2008-0235) included a proxy for IFRS transitional costs in the amount of $100,000, which was prorated over 4 years to an estimated annual cost of $25,000 for rate-making purposes. This annual amount for the three years ending 2009, 2010 and 2011 totals $75,000 and has been removed from proposed IFRS transitional costs through to December 31, 2011 from the amounts proposed for recovery with the 2013 Cost of Service application. The remaining portion for 2012 in the amount of $25,000 has been applied against account 1508 during the fiscal year ending December 31, 2012.

1518 RETAIL COST VARIANCE ACCOUNT – RETAIL

This account is used to record the net of revenues derived from establishing Service Agreements, distributor-consolidated billing, and the costs of entering into Service Agreements, and related contract administration, monitoring, and other expenses necessary to maintain the contract, as well as the incremental costs incurred to provide the services described above, and the avoided cost credit arising from retailer-consolidated billing.

1548 RETAIL COST VARIANCE ACCOUNT – SERVICE TRANSACTION REQUEST

This account is used to record the net of revenues, including accruals, derived from the Service Transaction Request services and charged by the distributor in the form of a request fee, processing fee, information request fee, and the incremental cost of labour, internal information system maintenance costs, and delivery costs related to the provision of the services associated.

London Hydro received Board approval for disposition of $85,391 Retail Cost Variance Account (RCVA) 1518 balance, and for recovery of $89,918 RCVA 1548 balance in its 2013 COS rate application (EB-2012-0146). These amounts consisted of the year-to-date audited balances at December 31, 2011. The resulting rate riders expired on April 30, 2014.

The following Table 9-3 – Retail Costs Variance Accounts Summary reflects the 2015 audited balances that have been requested for recovery with this application.

Table 9-3 – Retail Costs Variance Accounts Summary

Retail Cost Variance Accounts	Net Accruals / Variances	Carrying Charges	Ending Balances at Dec. 31, 2015	Projected Interest Jan 16 to Apr 30/17 - 1.10%	Projected Balances as at Apr 30/17
1518 Retail Cost Variance Account - Retail	$ 86,222	$ 1,672	$ 87,894	$ 1,260	$ 89,154
1548 Retail Cost Variance Account - STR	(91)	(69)	$ (160)	(1)	$ (161)
	$ 86,132	**$ 1,602**	**$ 87,734**	**$ 1,259**	**$ 88,993**

The forecasted interest on December 31, 2015 principal balances is calculated using the Board's prescribed rate of 1.10% for the period of January 1, 2016 to April 30, 2017.

London Hydro confirms that all costs incorporated in the calculation of the principal amounts are incremental costs of providing retail services.

London Hydro confirms that it followed the accounting treatment described in Article 490, Retail Services and settlement Variances of the Accounting Procedures Handbook for Account 1518 and Account 1548.

The carrying charge is calculated using the Board prescribed interest rate for the respective quarterly period and applied to the monthly opening balances.

In accordance with Chapter 2 of the Board's Filing Requirements for Electricity Distribution Rate Applications, a detailed schedule identifying the revenues and expenses by Uniform System of Accounts (USoA) account number that are incorporated into the variances recorded in Account 1518 and 1548, including the forecast for 2016 and 2017 is included in this section.

Transactions	USoA	2012	2013	2014	2015	2016	2017
Retailer Charges	4082	$ (139,561)	$ (119,353)	$ (104,398)	$ (92,212)	$ (82,449)	$ (73,410)
Incremental Expenses to provide retail services	5315	162,228	119,657	127,023	132,837	148,080	149,528
RCVA Retail	**1518**	**$ 22,668**	**$ 304**	**$ 22,625**	**$ 40,626**	**$ 65,632**	**$ 76,118**
STR Charges	4084	$ (5,628)	$ (4,180)	$ (2,745)	$ (2,951)	$ (2,925)	$ (2,850)
Incremental Expenses to provide retail services	5315	3,847	3,895	3,951	3,720	3,720	3,720
RCVA STR	**1548**	**$ (1,781)**	**$ (285)**	**$ 1,207**	**$ 769**	**$ 795**	**$ 870**

The drivers of the balances in the Retail Cost Variance Accounts 1518 and 1548 are the costs of providing retail services and revenue collected from retailers. The revenue collected from retailers is affected by the number of customers signed up with the retailers.

There is an apparent downward trend in the number of retailer associated customers and, consequently, in the amount of revenue collected from the retailers derived from fees based on the number of transactions.

Year	2012	2013	2014	2015	2016	2017
Number of retail customers at year-end	12,843	11,168	9,748	8,589	7,567	6,706

This Application includes a request for disposition of these balances through the proposed rate rider.

London Hydro will continue the use of Retail Cost Variance Accounts 1518 and 1548.

1568 LRAM VARIANCE ACCOUNT

A detailed description and calculation supporting the LRAMVA claim is included in Exhibit 4 – Operating Expenses in accordance with the Filing Requirements.

The amount proposed for disposition is included in the Continuity Schedule, and resulting rate riders were calculated within the 2017 EDDVAR Continuity Schedule Work Form.

Adjustments were made to the December 31, 2015 balance of Account 1568 LRAMVA due to the following factors:

- The OEB issued its most recent Guideline on LRAMVA, Report of the OEB: Updated Policy for the Lost Revenue Adjustment Mechanism Calculation: Lost Revenues and Peak Demand Savings from Conservation and Demand Management Programs (EB-2016-0182 – the "LRAMVA Report"), on May 19, 2016. According to this guideline no peak demand (kW) savings from Demand Response (DR) programs should be included in the LRAMVA calculation. London Hydro, therefore, removed the lost revenue calculated from peak demand savings resulting from DR programs from the audited balance on December 31, 2015.
- The OEB created a new Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) Work Form – Version 1.0 (2017), issued on July 8, 2016, updated on August 4, 2016. The LRAMVA Work Form must be completed and submitted with an LRAMVA claim in a Cost of Service application according to Chapter 2 of the Filing Requirements. The persistence rates were initially assumed at 100% for each program persisting into future years. London Hydro calculated and applied the persistence factors to programs using the LRAMVA Work Form methodology and updated the existing LRAMVA calculations for years 2013 to 2015.
- The IESO issued the Final 2015 Annual Verified Results Report for London Hydro on June 30, 2016. Lost revenues resulting from 2015 savings from 2015 programs were originally estimated using forecasted savings. London Hydro updated the 2015 estimated values to the actual values of energy and demand savings based on the Final 2015 Annual Verified Results Report and adjusted the LRAMVA balance accordingly.

London Hydro will continue the use of 1568 LRAM Variance Account.

1592 PILS AND TAX VARIANCES - SUB-ACCOUNT SAVINGS ON IMPLEMENTATION OF HST

This account is used to record amounts repayable to customers associated with incremental Input Tax Credits (ITCs) as a result of elimination of the Provincial Sales Tax (PST) and the implementation of Harmonized Sales Tax (HST) effective July 1, 2010.

Due to the implementation of HST on July 1, 2010, the Ontario 8% PST was eliminated as a cost to London Hydro. Prior to July 1, 2010, PST was unrecoverable and therefore represented an expenditure. In order to recognize the savings associated with this incremental ITC, the Board directed distributors to record implicit PST included in distribution rates in a new sub-account under 1592, PILs and Tax Variances for 2006 and Subsequent Years described as HST / OVAT Input Tax Credits (ITCs).

As directed, London Hydro established 1592 PILs and Tax Variances Sub-account Savings on Implementation of HST and has accumulated a liability up until the end of Year 2012. Carrying charges are applied until April 30, 2017.

London Hydro requested and received an approval for disposition of the $191,022 audited balance accumulated as of December 31, 2011, including applicable carrying charges to April 30, 2013 in account 1592 PILs and Tax Variances Sub-account Savings on Implementation of HST in its 2013 Cost of Service rate application (EB-2012-0146). The 2013 Cost of Service rate application also included a request that this account continue in order to provide for recording of the HST liability associated with the forthcoming year ending December 31, 2012.

HST Savings Liability

	2010 July - Dec	2011 Jan - Dec	Claimed 2011 YTD Total	2012 Jan - Dec
OM&A	113,537	227,073	340,610	227,072
Depreciation	2,027	28,455	30,482	80,100
	$ 115,564	$ 255,528	$ 371,092	$ 307,172
Portion repayable at 50%			**185,546**	**153,586**
Carrying charges			5,476	9,628
Claim			**$ 191,022**	**$ 163,214**
Approved for recovery with 2013 COS (EB-2012-0146)			**(191,022)**	
Balance of Account 1592 PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)			**$ -**	**$ 163,214**

London Hydro is requesting the disposition of the remainder of this liability in this Application, an audited balance of $163,214, which is at the rate of 50%, consistent with how the Board has treated tax changes in the second and third generation IRMs.

As suggested in the Board's Accounting Procedures Handbook Frequently Asked Questions, issued December 2010, and in order to avoid administrative costs associated with recording this incremental ITC on a transactional basis, London Hydro used the simplified approach as described under Q & A #4 by performing a one-time analysis to serve as a proxy.

The liability accumulated for PST savings associated with OM&A expenditures was derived by reviewing actual expenditures for the 2009 fiscal year and segregating those accounts which were subject to PST. The implicit PST included in these expenditures was then used as the basis on which to estimate the PST savings and associated amount included in rates for the period commencing July 1, 2010 and ending December 31, 2012 to be repaid to customers.

London Hydro accumulated the liability for PST savings associated with the depreciation of capital assets based on actual capital additions for the 2009 fiscal year subject to PST. Implicit depreciation expense for the period July 2010 to December 2012 was then calculated using an average life span of 21.4 years and applying the ½ year rule in the year of acquisition. Also, estimated additions post-July were adjusted to take into consideration those flowing from inventory and construction works-in-progress on hand at the end of June, 2009.

London Hydro proposes the discontinuation of account 1592 PILs and Tax Variances Sub-account Savings on Implementation of HST after its disposition on May 1, 2017.

1555 SMART METER CAPITAL AND RECOVERY OFFSET VARIANCE ACCOUNT, SUB-ACCOUNT STRANDED METER COSTS

The balance of 1555 Sub-account Stranded Meter Costs represents the residual balance of the net book value of stranded meters submitted for recovery and approved for disposition, with the 2013 Cost of Service Rate Application (EB-2012-0146) and the balance of carrying charges related to the account.

The amount approved for recovery is reflected in the Sub-account Stranded Meter Costs of Account 1555, and the associated recoveries collected through a separate rate rider are also recorded in this same account in accordance with the accounting treatment described in Guideline G-2011-0001 Smart Meter Funding and Cost Recovery – Final Disposition, Appendix A-1, and in the Accounting Procedures Handbook Frequently Asked Questions July 2012, Question 10. The approved rate rider was in effect from May 1, 2013 until April 30, 2014.

Interest carrying charges were applied on the monthly opening net principal balance effective the date of the rate order, using the Board's prescribed interest rates. The rate of interest is the rate prescribed by the Board for the respective quarterly period. No interest carrying charges applied to the balances recorded in the sub-account prior to the effective date of the rate order approving the recovery of the stranded meter costs.

Sub-account Stranded Meter Costs	Residential		GS < 50 kW		Total	
NBV per Customer Class approved for recovery	$	2,611,856	$	542,225	**$**	**3,154,081**
Interest Earned After May 1, 2013	$	24,292	$	5,028	**$**	**29,320**
Recoveries						
Principal recoveries	$	(2,608,422)	$	(542,225)	**$**	**(3,150,647)**
Interest recoveries	$	-	$	(2,273)	**$**	**(2,273)**
Balance as of December 31, 2015	**$**	**27,726**	**$**	**2,755**	**$**	**30,482**
Carrying Charges January 1, 2016 - April 2017	$	50	$	-	**$**	**50**
Balance proposed for recovery	**$**	**27,777**	**$**	**2,755**	**$**	**30,532**

The 2017 EDDVAR Continuity Schedule reflects the $30,482 account balance at December 31, 2015. The account balance reported in the trial balance through the Electricity Reporting and Record-keeping Requirements is $30,438, as documented in London Hydro's Audited Financial Statements. London Hydro made a $44 adjustment in Year 2016 to interest earned after May 1, 2013 due to the interest recoveries were originally recorded as principal recoveries. The principal was fully recovered for the GS <50 kW rate class along with some interest recoveries. The Residential rate class still has $3,434 principal that has not been recovered. A small adjustment to interest calculations was required after the recoveries applied properly within each rate classes.

The outstanding residual balance is $30,532, of which $27,098, or 89%, is interest. Due to the fact that the remaining principal is insignificant, at $3,434 or 11%, and the balance mainly consists of interest, London Hydro respectfully requests that the residual balance be transferred to Account 1595 Disposition and Recovery/Refund of Regulatory Balances. The Company proposes that the balances are added to the amounts for disposition to each respective rate class in the calculation of the DVA rate riders.

Row 43 on Tab *5 Allocation of Balances* in the 2017 Continuity Schedule Work Form is updated to include Account 1555 Sub-account Stranded Meter Costs residual balance in the allocated amounts to Residential and General Service less than 50 kW customer classes, as presented below. This amount is proposed for disposition through the Rate Rider for Group 2 Accounts.

Sub-account Stranded Meter Costs	Residential	GS < 50 kW	Total
Principal	$ 3,434	$ -	$ 3,434
Interest	$ 24,342	$ 2,755	$ 27,098
Balance proposed for recovery	**$ 27,777**	**$ 2,755**	**$ 30,532**

London Hydro proposes the discontinuation of 1555 Smart Meter Capital and Recovery Offset Variance Account, Sub-account Stranded Meter Costs after its disposition on May 1, 2017.

RENEWABLE GENERATION CONNECTION AND SMART GRID DEVELOPMENT DEFERRAL ACCOUNTS – CLIMATE CHANGE PROJECTS

The Green Energy and Green Economy Act, 2009 (GEA) came into force on September 9, 2009, and laid the foundation for further exploration of the impact of green business and clean technology on the economy. The GEA defined smart grid by way of amendment to the Electricity Act, 1998 as "the advanced information exchange system and equipment that when utilized together improve the flexibility, security, reliability, efficiency and safety of the integrated power system and distribution systems, particularly for the purpose of, (a) enabling the increased use of renewable energy sources and technology, including generation facilities connected to the distribution system; (b) expanding opportunities to provide demand response, price information and load control to electricity customers; (c) accommodating the use of emerging, innovative and energy saving technologies and systems control applications; or (d) supporting other objectives that may be prescribed by regulation." (*GEA 2009, Chapter 12, Schedule B, Section (5))* The Ontario Energy Board Act, 1998 was also amended to promote electricity conservation and demand management, facilitate the implementation of a smart grid in Ontario, and promote the use and generation of electricity from renewable generation including distribution system upgrades to accommodate the connection of renewable energy generation facilities.

The Board provided distributors with various guidelines (OEB Guidelines) in response to the Directive from the Minister of Energy dated November 23, 2010 (Minister's Directive), setting out the requirements and expectations for the distributors' proposed plans for the development, implementation and promotion of the smart grid.

The Ontario Energy Board's *Report of the Board – A Renewed Regulatory Framework for Electricity Distributors: A Performance Based Approach* (the RRFE Report) was issued on October 18, 2012. The RRFE Report indicated that smart grid investments are considered integral to all utility investment and that smart grid development is expected to be coordinated on a regional basis in order to achieve economies of scope and scale.

The Board created four new deferral accounts in the Uniform System of Accounts to allow distributors to begin recording expenditures related to accommodating renewable generation and smart grid development, in its *Guidelines: Deemed Conditions of Licence: Distribution System Planning* (G-2009-0087), issued on June 16, 2009. The four deferral accounts are 1531 Renewable Connection Capital Deferral Account, 1532 Renewable Connection OM&A Deferral Account, 1534 Smart Grid Capital Deferral Account and 1535 Smart Grid OM&A Account.

The Board also described the type of expenditures that may be recorded in each deferral account in its *Filing Requirements: Distribution System Plans – Filing under Deemed Conditions of Licence* (EB-2009-0397), originally issued March 25, 2010, revised May 17, 2012. These descriptions are also referenced in Chapter II: Uniform System of Accounts (USoA) of the *Accounting Procedure Handbook For Electricity Distributors*.

- 1531 Renewable Connection Capital Deferral Account: Investments associated with expansions to connect renewable generation facilities and renewable enabling improvements, as well as and capital cost of changes to the Customer Information System (CIS System) to enable the automated settlement of FIT or microFIT contracts may be included in this account.

- 1532 Renewable Connection OM&A Deferral Account: Incremental operating, maintenance, amortization and administrative expenses directly related to expansions to connect renewable generation facilities and renewable enabling improvements, OM&A costs associated with changes to the distributor’s CIS System to enable automated settlement of FIT or microFIT contracts, expenses associated with preparing a GEA Plan.

- 1534 Smart Grid Capital Deferral Account: Investments related to smart grid demonstration projects and costs of smart grid investments that are undertaken as part of a project to accommodate renewable generation are recorded in this account.

- 1535 Smart Grid OM&A Account: Operating, maintenance, amortization and administrative expenses directly related to smart grid development activities including smart grid demonstration, smart grid studies and planning exercises, and smart grid education and training are included in this account.

London Hydro took part in numerous smart grid pilot programs and initiatives to explore and investigate innovative technologies, develop more efficient grid voltage control, explore opportunities to increase connectivity of renewable generation, improve cyber security and customers' access to energy use data, and improve customer value. The list of such projects London Hydro participated in is presented in Table 9-4 – Summary of Climate Change Projects with the audited account balances presented in London Hydro's Audited Financial Statements as at December 31, 2015. The audited account balances are also reported in E2.1.7 Reporting and Record-keeping Requirements (Trial Balance) on December 31, 2015. London Hydro followed the OEB's guidelines to record all relevant expenditures.

Table 9-4 – Summary of Climate Change Projects

Climate Change Projects	1531 Renewable Connection Capital	1532 Renewable Connection OM&A	1534 Smart Grid Capital	1535 Smart Grid OM&A
CIS Modifications to Automate microFit and FIT Settlements	$ 30,353			
Green Button Pilot Project			$ 370,751	$ 121,154
Collaborative Research Projects with Western University and Ontario Centres of Excellence		$ 118,824		$ 21,133
Smart Grid Fund Project: VAR Compensator Devices			$ 18,919	
Integrated Energy Mapping Project: City of London				$ 10,000
NSERC Project: BioGenerator				$ 26,345
Electric Vehicle Study - EMAP Project				$ 132,289
Electrovaya EV Charger/Battery				$ 161
Total Spending	**$ 30,353**	**$ 118,824**	**$ 389,670**	**$ 311,081**
Amortization	(24,130)	24,130	(69,865)	69,865
Principal Balance	**$ 6,222**	**$ 142,954**	**$ 319,804**	**$ 380,946**
Interest	1,625	5,356	6,026	8,126
Audited Account Balance at December 31, 2015	**$ 7,848**	**$ 148,311**	**$ 325,831**	**$ 389,072**

This application includes a request to recover $654,165 revenue requirement for years 2010 to 2016 arising from the costs of the programs recorded in the existing four deferral accounts for renewable generation connection and smart grid development through the proposed Climate Change Projects Rate Rider and to transfer the capital assets into its rate base.

London Hydro also proposes the discontinuation of each of these four accounts, namely: 1531 Renewable Connection Capital Deferral Account, 1532 Renewable Connection OM&A Deferral Account, 1534 Smart Grid Capital Deferral Account and 1535 Smart Grid OM&A Account, following the approval of the recovery effective May 1, 2017.

Each project is described in more detail with relevant references in this section.

CALCULATION OF REVENUE REQUIREMENT AND DISPOSITION

London Hydro used the ED Capital OMA Disposal Generator model (ED Model), a separate rate model, to calculate the revenue requirement for recovery of the cost of climate change projects recorded in the deferral accounts and did not include any of the balances in the 2017 EDDVAR Continuity Schedule Work Form for rate rider calculation purposes. The rate riders were calculated using the ED Model.

The ED Model was updated with the applicable Cost of Service parameters relevant to each element of the revenue requirement calculation.

Interest carrying charges applied on the monthly opening net principal balances using the Board’s prescribed interest rates for each respective period.

Capital investments and related OM&A costs data reflected in Table 9-5 – Summary of Capital and OM&A Costs include expenditures up to December 31, 2016, and agree with the balances recorded in London Hydro’s deferral accounts. The VAR Compensator installation was completed in 2016. This capital costs is reflected in the Capital Cost Data. The Electrovaya EV Charger/Battery project was cancelled in 2016 and, therefore, the cost of this initiative is removed from 1535 Smart Grid OM&A account.

Table 9- 5 – Summary of Capital and OM&A Costs

Capital Costs Data:	2010	2011	2012	2013	2014	2015	2016	TOTAL
Software CIS	$ 9,953		$ 19,900	$ 500				$ 30,353
Software Green Button				$ 6,793	$ 307,751	$ 56,207		$ 370,751
Var Compensator						$ 18,918	$ 3,621	$ 22,540
Total Capital Costs	**$ 9,953**	**$ -**	**$ 19,900**	**$ 7,293**	**$ 307,751**	**$ 75,125**	**$ 3,621**	**$ 423,643**

Operating Expenses Data:	2010	2011	2012	2013	2014	2015	2016	TOTAL
2.1 Green Button				$ 17,669	$ 61,234	$ 42,251		$ 121,154
2.2 NSERC Project					$ 6,682	$ 19,662		$ 26,345
2.3 Research Projects with UWO and OCE	$ 26,815	$ 111,627	-$ 66,991	$ 2,506	$ 66,000	$ -	$ -	$ 139,957
2.3.1 Watts Lab		*$ 93,617*	*-$ 74,991*	*$ 2,506*				*$ 21,133*
2.3.2 Renewable Generation Studies	*$ 26,815*	*$ 18,009*	*$ 8,000*	*$ -*	*$ 66,000*			*$ 118,824*
2.4 London Energy Mapping		$ 10,000						$ 10,000
2.5 EMAP				$ 37,892	$ 84,238	$ 10,159		$ 132,289
Total OM&A Costs	**$ 26,815**	**$ 121,627**	**-$ 66,991**	**$ 58,067**	**$ 218,154**	**$ 72,072**	**$ -**	**$ 429,744**

Both software assets and the VAR compensator device asset have a five-year asset life. The return on rate base and a five-year straight amortization related to each capital asset is calculated. Annual revenue requirement before PILs includes the return on rate base, incremental OM&A and depreciation expenses. The annual revenue requirement, after PILs were applied, is generated for years 2010 to 2016 and summarized in Table 9-6 – Summary of Annual Revenue Requirement.

Details of calculations are enclosed in Appendix C – ED Capital OM&A Disposal Generator, and a working Excel model is included with this application.

Table 9-6 – Summary of Annual Revenue Requirement:

Description	Amount
Revenue Requirement - 2010	$ 26,779
Revenue Requirement - 2011	$ 124,426
Revenue Requirement - 2012	$ (64,708)
Revenue Requirement - 2013	$ 64,638
Revenue Requirement - 2014	$ 229,297
Revenue Requirement - 2015	$ 131,875
Revenue Requirement - 2016	$ 119,503
Revenue Requirement - 2017	$ -
Revenue Requirement - 2018	$ -
Revenue Requirement - 2019	$ -
Total Revenue Requirement	$ 631,809
Rate Adder Collected	$ -
Carrying Cost / Interest	$ 22,356
Proposed Climate Change Projects Disposition Recovery	$ 654,165

London Hydro respectfully requests these expenditures be considered final and the accounting recognition of the investments in fixed assets. This would require the accounting reclassification of these expenditures recorded in the deferral accounts to their applicable USoA accounts, instead of Account 1595. Following the reclassification clearance of amounts from the deferral accounts to the applicable USoA accounts, no further true up would be required.

The transfer of the net book value of climate change project assets is reflected in Table 2-2 – Summary of Continuity Schedules of Exhibit 2 “Rate Base”, Tab 1, Schedule 1, in accordance with *Chapter 2 Filing Requirements, Sec 2.2.1.1 Overview.*

Modifications to London Hydro’s Customer Information System to Enable the Automated Settlement of microFIT and FIT Contracts

The Board’s *Filing Requirements: Distribution System Plans – Filing under Deemed Conditions of Licence* (EB-2009-0397) states that the capital cost of changes to a distributor’s Customer Information System (CIS) to enable the automated settlement of FIT or microFIT contracts may be included in Account 1531 Renewable Generation Connection Capital Deferral Account.

London Hydro has customers with FIT and microFIT contracts requiring monthly settlement for electricity generation activities. The Company made modifications to its Customer Information System to automate the settlements. The capital cost for the required code changes was recorded in 1531 Renewable Connection Capital Deferral Account in the amount of $30,353. The code changes are in-service and, therefore, being amortized over a five-year period.

Summary of Expenditures

CIS Billing System Modifications	Expenditures
microFit Billings	$ 9,953
FIT Billings	$ 20,400
Total Expenditures	**$ 30,353**

There were no other investments associated with expansions to connect renewable generation facilities and renewable enabling improvements made by London Hydro.

Green Button Pilot Project

London Hydro developed the Green Button application to help customers manage their energy consumption. The costs related to the initial pilot phase of the software development and its introduction to its customer base were recorded in accounts 1534 Smart Grid Capital Deferral Account and 1535 Smart Grid OM&A Deferral Account according to the OEB's guidelines described in its *Filing Requirements: Distribution System Plans – Filing under Deemed Conditions of Licence* (EB-2009-0397).

As of December 31, 2015, Green Button capital costs were $370,751 and OM&A expenses totaled to $121,154.

The genesis of the Green Button project at London Hydro was a response to two main calls to action – one from the Ontario Ministry of Energy and one from the Ontario Energy Board –to explore ways to leverage the province's world-leading investment in smart meters for greater conservation and economic growth.

- In November 2012, the McGuinty Government released a statement indicating that a working group had been created – led by the province and the MaRS Discovery District – to explore an Ontario Green Button initiative that would use "innovative smart grid technology to give families and businesses direct, timely access to their own energy data through a secure download from their utility's website. A standard data format would encourage app developers to create new tools to help Ontario customers manage their energy use from their computers and smart devices."
- The Ontario Energy Board's guidance was provided in the *Report of the Board - Supplemental Report on Smart Grid* (EB-2011-0004), issued February 11, 2013, which states "distributors must explore mechanisms that facilitate "real-time" data access and "behind the meter" services and applications for the purpose of providing customers with the ability to make decisions affecting their electricity costs."

The nature of London Hydro's Green Button initiatives are discussed in detail in Exhibit 4, Tab 1, Schedule 5, *London Hydro Programs, Information Technology and Corporate*

Communications sections. The following section will discuss the nature of the costs included in the initial pilot project.

Summary of Capital Expenditures

Green Button Pilot Capital Expenditures		Amount
Application Development Costs	$	471,730
Presence Pro Energy with Green Button	$	31,847
Vulnerabiltiy Assessment	$	10,746
MaRS Discovery District Funding	$	(136,522)
Ontario Centres of Excellence (TalentEdge)	$	(10,000)
Certification	$	2,950
Total Expenditures	**$**	**370,751**

- Development costs include design, development, acceptance testing, and implementation of the pilot solution of Green Button application.

- Presence Pro Energy integration with Green Button application, Real-time meter reading, Smart-plug and robotic camera control for pilot phase implementation.

- A vulnerability assessment was performed to ensure the Green Button online application website is secure.

- The MaRS Discovery District funded a portion of the development costs for London Hydro's Green Button software.

- The Ontario Centres of Excellence TalentEdge program provides funding to enable students and recent graduates to gain hands-on experience with companies. One student was involved in Green Button IT work and London Hydro received $10,000 in funding towards his direct labour costs.

- London Hydro completed the Green Button Download My Data certification tests with Underwriters' Laboratories, which authenticates that the Green Button data is secure, accurate and works with the data format.

- Amortization of Green Button software is based on a five-year service life.

Today, all of London Hydro's customers are able access their consumption data through Green Button. London Hydro became an industry leader through the innovative development of the original pilot application of the Green Button program.

The capital costs for the Green Button development were recorded in 1534 Smart Grid Capital Deferral Account.

Summary of OM&A Expenses

Green Button Pilot OM&A Expenditure		Amount
Development of marketing strategy	$	15,744
Advertising and promotion	$	89,992
Website development and hosting	$	26,912
Green Button logo development	$	4,250
MaRS Discovery District Funding	$	(15,744)
Total Expenditures	**$**	**121,154**

London Hydro also incurred non-capital expenses to promote the Green Button initiative to its customers. These operating expenses consist primarily of non-discretionary corporate communications expenses, such as marketing, billing inserts, displays, directly related to London Hydro's Green Button Initiative. Activities in this regard are detailed in Exhibit 4, Tab 1, Schedule 5, *London Hydro Programs, Corporate Communications*. The MaRS Discovery District funded a portion of these costs as well.

Green Button related OM&A expenses were recorded in 1535 Smart Grid OM&A Deferral Account.

Collaborative Research Projects with Western University and Ontario Centres of Excellence

Western University (UWO) and London Hydro have been developing and enhancing their research relationship over the past decade. A significant focus of much of the collaborative research over the past several years has been directed toward renewable generation and its effects on electrical transmission and distribution systems. Several IEEE papers have been published jointly by UWO and London Hydro staff with professors, engineers and graduate students working together. These papers include "*A hardware prototype model for electric vehicle load management in a distribution network*"; "*Characterization of harmonics in a utility feeder with PV distributed generation*"; and "*Real-Time Digital Simulation of a PV solar system as STATCOM (PV-STATCOM) for voltage regulation and power factor correction".*

The research initiatives led to recognition by the Ontario Centres of Excellence (OCE) for further collaborative development opportunities. One initiative *"Smart Management and Control of Short Circuit Currents to Increase Connectivity of Renewable Resources in Transmission and Distribution Grids of Ontario"* was a joint effort that included University of Waterloo, Western University, Ryerson University, Hydro One Networks, London Hydro, Bluewater Power, German Solar, Kaco New Energy and the IESO. Another project with OCE was called *"Increasing Renewable Generation Connectivity in the Transmission System of Ontario through use of Innovative DG Controls"* and the partners in this project were Western University, University of Waterloo, IESO, Hydro One Networks, London Hydro, Bluewater Power, Canasia, and Testforce. In total, London Hydro contributed $139,957 to this research work including the use of London Hydro facilities in the form of a solar lab that included a solar simulator and solar array.

Summary of Expenditures

Collaborative Research Projects with Western University and Ontario Centres of Excellence				**Amount**
<u>Account 1532 Renewable Connection OM&A Deferral Account</u>				
Collaborative contributions to studies on increasing connectivity of renewable energy sources			$	118,824
<u>Account 1535 Smart Grid OM&A Deferral Account</u>				
Solar lab testing and monitoring equipment	$	93,627		
Legal fees for patent filing	$	2,506		
London Economic Development Corporation funds	$	(75,000)	$	21,133
Total Expenditures			**$**	**139,957**

The costs have been recorded and allocated according to the OEB Guidelines, which state that the costs of smart grid investments that are undertaken as part of a project to accommodate renewable generation should be recorded in the relevant smart grid deferral account. The contributions to various studies to increase the connectivity of renewable energy sources are recorded in Account 1532 Renewable Connection OM&A Deferral Account. The smart grid portion of expenses, which consists of the net cost of the solar lab equipment, is recorded in Account 1535 Smart Grid OM&A Deferral Account.

Some of the research is still ongoing and London Hydro has seen many benefits in fostering the collaborative relationship between academic and utility industry innovators. In one research initiative, London Hydro performed on-site measurements of a lightly loaded feeder that had multiple Solar FIT generators connected in proximity under different live scenarios, while Western provided theoretical transient analysis of these scenarios simulating Hydro One capacitor switching. The purpose of this investigation was to determine the impacts of harmonics due to solar connections. London Hydro provided access to real world operational infrastructure while UWO leveraged their academic analysis tools and research methods.

Other indirect benefits to this collaborative effort are also realized. Professors at UWO have approached London Hydro for input into fourth year projects, thesis topics, research topics, and to enquire about industry needs. This opportunity has improved the quality of engineering graduate, which benefits the industry as a whole. Several of the new engineering hires at London Hydro have been directly related to this collaborative effort.

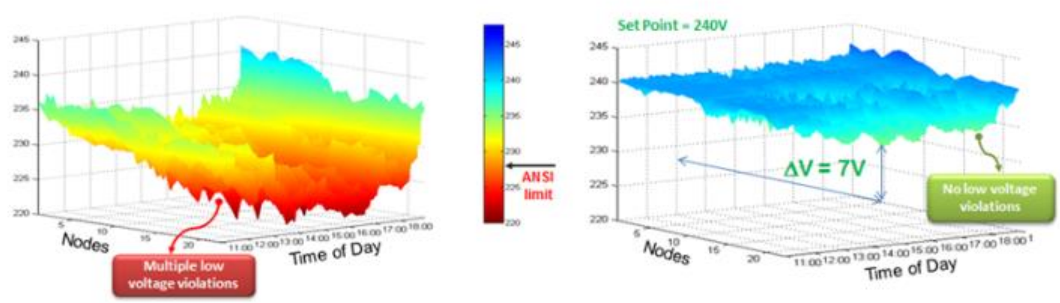
London Hydro’s Participation in a Smart Grid Fund Project – VAR Compensator Devices

In 2014, London Hydro assisted a company called Varentec to prepare an application for funding from the Ontario Ministry of Energy’s Smart Grid Fund (SGF) program. This fund supports high-value opportunities to advance energy innovation in Ontario.

Varentec’s application included involvement from London Hydro as a Collaborator on the project. As a Collaborator, London Hydro contributed financial support, industry expertise and permission to install devices on London Hydro’s existing high voltage grid. The SGF allows Collaborators, such as London Hydro, to recover up to 50% of eligible expenses relating to the costs associated with the project. Other utilities including Enwin, Hydro One and Entegrus also joined Varentec in this application as Collaborators.

Varentec was successful in their application and, in the summer of 2015, London Hydro installed 30 Dynamic Voltage/VAR control units (10 kVAR each) on one of its feeders. The Varentec units were installed at single phase pole-mounted transformer locations in the southeast part of London Hydro’s service territory. The units help the performance of London Hydro’s system by improving the power quality by tightening the range of voltage provided to the customer and minimizing voltage variations. The Varentec units also shorten the duration of voltage disturbances by providing reactive power support (i.e. injection of VARS as needed). These units communicate wirelessly and provide increased visibility into the performance of London Hydro’s grid by reporting the voltage at the point of installation. The units have been in service for approximately one year and they are performing as designed.

The following image illustrates the ability of the devices to tighten the voltage range.



Before – Larger voltage fluctuation *After- Smaller voltage fluctation*

The expenditures for this project have been recorded in 1534 Smart Grid Capital Deferral Account.

Summary of Expenditures

Varentec Compensator Devices	Expenditures	
Engineering and Installation costs of capacitors	$	35,759
Smart Grid Fund	$	(13,219)
Total Expenditures	**$**	**22,540**

Integrated Energy Mapping Project

Recognizing the challenge of energy use and greenhouse gas reduction contrasted with the increasing trend in energy consumption and greenhouse gas emissions, the Canadian Urban Institute (CUI), in partnership with the Ontario Power Authority (OPA), Natural Resources Canada CANMETEnergy, and the Ontario Centres of Excellence launched the Integrated Energy Mapping for Ontario Communities (IEMOC) initiative to help communities in Ontario develop a coordinated land and energy use planning process within a municipality.

The new approach proffers the municipality and local distributors with a common platform to convey complex energy concepts and present findings from data analysis in a visual manner using geographic information systems. This approach also permits a more effective overall planning process, especially from the energy perspective. Given the potential for a significant change to the energy landscape, the OPA intended to test the effectiveness of this approach in a limited number of communities across Ontario, including London. Some examples of the expected benefits are the potential impact on land use planning, electrical infrastructure requirements of electric vehicles and their associated charging stations, embedded generation and other new opportunities.

London Hydro was asked by the City of London to participate in this project and contributed $10,000 along with in-kind resources to collect and manage energy data required for the project.

The final report titled "*City of London: Integrated Energy Mapping Strategy (L-IEMS)"* prepared by Canadian Urban Institute is enclosed in Appendix 9D.

Expenditures have been recorded in 1535 Smart Grid OM&A Deferral Account.

Natural Sciences and Engineering Research Council (NSERC) Project - BioGenerator

London Hydro participated in another smart grid exploration project in partnership with Western University. This patented system uses surplus or off-peak power to create hydrogen gas for use as a storage medium and then converts it back to electricity when needed using trillions of microorganisms (the BioGenerator), making the excess power completely dispatchable. The purpose of the system is to create a non-toxic environmentally friendly storage system, unlike current battery technology; this system is ideal for smoothing out the variability of renewable solar and wind generation.

London Hydro teamed up with Western University to provide in kind contributions, which were matched by an NSERC grant. The participation consisted of providing Lambton College with a $26,345 generator purchase in kind contribution.

Expenditures have been recorded in 1535 Smart Grid OM&A Deferral Account.

Electric Vehicle Study – Electric Mobility Adoption and Prediction (EMAP)

Well before the provincial government released its *Five-Year Climate Change Action Plan: 2015 - 2020*, there was an understanding that transportation was a significant contributor to greenhouse gas (GHG) emissions in this province and, consequently, an interest in promoting electric vehicles (EV) as an element of the overall GHG abatement strategy.

Recharging electric vehicles represents a significant household electric load (comparable to electric storage tank water heaters, electric stoves, etc.), and, consequently, the community of LDC's started questioning whether their distribution infrastructure (distribution transformers, primary cables, secondary service cables, etc.) was sufficient to accommodate a sudden influx of consumer interest in electric vehicles.

Distribution system philosophies have changed over time, so the LDC's were interested in both (i) which residential subdivisions within their respective service territories were most vulnerable, (i.e. would most likely require an upgrade to the distribution system infrastructure), and (ii) which elements were the weakest in the overall supply path (i.e. there is little use in upgrading transformers if the weakest element is the secondary service cables between the transformer and the home).

To this end, London Hydro undertook a comprehensive study comprised of three (3) distinct elements:

(i) Pollution Probe was engaged essentially to undertake a demographic study (i.e. what type of customer has "*early adopter*" characteristics for electric vehicles, and in what parts of the city are such customers mostly clustered). The final report published under the title *Electric Mobility Adoption and Prediction* (EMAP Report) summarized the process, findings and implications that emerged from the study. It proposed a set of objectives and recommendations intended to prepare London Hydro to manage and support the use of electric vehicles in its service area. The EMAP Report is enclosed in Appendix 9E.

Note: Several LDC's (Toronto, Ottawa, Horizon and perhaps others) engaged Pollution Probe to carry out similar studies at a similar point in time. The demographic make-up of these communities is so different that the study outcomes aren't necessarily transferable from one community to the next. For example, in downtown Toronto, the oldest housing stock tends to be in very affluent and trendy neighborhoods often occupied by high-income earners, whereas in London, the oldest housing stock is generally reflective of less affluent neighborhoods often occupied by renters that lack the disposable income to be considered early adopters for electric vehicles.

(ii) Three (3) university engineering students were engaged under the direction of an experienced engineer, in concert with a subject matter expert in numerical analysis at Western University's Engineering Faculty, to carry out a theoretical probability analysis using Monte Carlo simulation techniques primarily to identify the weakest elements in the various vintages of distribution layouts. This element of the overall project was eligible and received partial funding from the Ontario Centres of Excellence's internship funding initiative. Due to this valuable and relevant work experience, all three (3) engineering students entered post-graduate careers.

(iii) Another university engineering student was engaged under the direction of another experienced electrical engineer to carry out a different theoretic analysis by leveraging distribution configuration information from London Hydro's GIS in conjunction with revenue metering data from London Hydro's AMI (i.e. Smart-metering system) to identify specific distribution system transformers that may not have sufficient residual capacity to accommodate the additional load imposed by several home EV chargers.

The outcome of this work is (i) a few small areas of the city have been identified as perhaps needing reinforcement at some future date, and (ii) London Hydro is confident that it has the technology in place (i.e. GIS in concert with AMI and ODS) to provide active monitoring and, consequently, will be able to provide system reinforcement on an as-needed basis, which is certainly a more cost-effective approach than implementing widespread upgrades based on a presumption that the market for EV's will skyrocket in the near term.

This foundational work is the catalyst for spawning more R&D efforts that would be classified as Smart-Grid activities. London Hydro is following developments with intelligent EV chargers and is considering implementing the OpenADR communications protocol as a mechanism for simultaneously providing customer choice and precluding overloading of distribution system assets when a cluster of EV's needs to be simultaneously recharged. Whereas the OpenADR (an acronym for Open Automated Demand Response) was adopted under the umbrella Smart-Grid portfolio of interoperability standards for demand response applications, the OpenADR Alliance is presently giving consideration to expanding the protocol definition to include load management functionality, with one such application being the coordination of intelligent EV chargers with the capacity limits of upstream LDC distribution transformers.

To keep abreast of changes in the landscape, London Hydro joined several organizations such as Electric Mobility Canada, an organization exclusively dedicated to the promotion of electric mobility. London Hydro's intention is to maintain membership in these organizations for as long as the perceived value exceeds the membership cost. Also, Plug'N Drive requested that London Hydro join a number of other LDC's by participating in their *Charge My Car* program. The *Charge My Car* initiative allows customers to purchase a variety of chargers online and it also notifies the LDC where such chargers have been installed. London Hydro has been actively involved and supported programs sponsored by Plug'N Drive, a dynamic not-for-profit organization with the mandate to accelerate the adoption of electric vehicles. Plug'N Drive has a great consumer-oriented guide for purchasing electric vehicles. To assist interested customers, London Hydro has arranged to make an electronic version of this resource available on its website.

London Hydro is committed to enhancing its responsiveness to the EV evolving patterns, continuing to build collaborative partnership in the industry and investing in educating customers about the EV technology.

Expenditures have been recorded in 1535 Smart Grid OM&A Deferral Account.

Summary of Expenditures

Expenditure		Amount
Assessment of the Impact of Plug-In Electric Vehicle Battery Charging on London Hydro`s Distribution System - application of the principles of probabilistic design to the analysis	$	48,745
Ontario Centres of Excellence (TalentEdge internship funding program)	$	(20,000)
Assessment at the neighbourhood level and leverage the information and relationships within London Hydro's Intergraph GIS system	$	62,500
Consulting re project scope and research objectives, presentations, coordination with Pollution Probe	$	28,296
SAE International Standardsand IEEE Standard publications	$	238
Electric Mobility Canada membership	$	2,510
Sponsorship of Plug'n Drive EV Roadshow at London Lifestyle Show	$	5,000
Membership fee in Plug'n Drive Charge My Car program	$	5,000
Total Expenditures	**$**	**132,289**

Electrovaya Electric Vehicle (EV) Charger / Battery

In 2013, the Ministry of Energy issued a Request for Proposal to the Ontario Smart Grid Fund (SGF). The SGF is intended to help accelerate the growth of Ontario's smart grid industry through targeted financial support for projects that advance the development of smart grid in Ontario and provide economic development opportunities, including the creation of new jobs. The timeframe of the project has a maximum duration of two years as defined under the terms of the Smart Grid Fund.

Electrovaya is a Mississauga-based company that designs and manufactures high density lithium ion batteries. Electrovaya, in collaboration with London Hydro, was awarded a demonstrative project that involved installation of three electric vehicle chargers, which are integrated with battery storage through intelligent control systems.

The goals of the project included gaining insight and experience associated with increasing infrastructure demands from Electric Vehicles (EVs) and experience with providing dynamic intelligent control of power quality issues (e.g., voltage control, frequency control, VAR support, and phase balancing) regarding EVs and other complex loads. The installations were intended to advance industry knowledge by providing real world data and usage patterns and effective solutions to power quality problems.

The Ministry of Energy and Electrovaya have jointly decided to terminate the EV Charger/Battery project that London Hydro was involved in as a Collaborator, due to a change in the battery design technology. Electrovaya is currently working on the formal paperwork with the Ministry to close out the project.

London Hydro spent $161 year-to-date on the project, an insignificant amount, which it does not submit for recovery with this application, and proposes to withdraw from 1535 Smart Grid OM&A Account.

ACCOUNTS NOT SUBMITTED FOR RECOVERY

London Hydro is not requesting recovery of the Deferral and Variance Accounts previously approved for recovery with disposition period that had not expired as of December 31, 2015 as part of this Application.

Table 9-7 – Deferral and Variance Accounts Not Submitted for Recovery with this Application

Accounts for which No Disposition is Requested in This Application		Net Accruals / Variances	Carrying Charges	Ending Balances at Dec. 31, 2015
Group 1 Accounts:				
1580	RSVA Variance WMS – Sub-account CBR Class A	$ 46,059	$ 146	$ 46,205
1589	RSVA - Global Adjustment – Existing Class A portion (*excluding new Class A*)	$ 1,205	$ (338)	$ 867
Group 2 Accounts:				
1575	IFRS-CGAAP Transitional PP&E Amounts	$ 157,307	$ -	$ 157,307
		$ 204,571	**$ (192)**	**$ 204,379**

1580 RSVA - WHOLESALE MARKET SERVICE CHARGES – SUB-ACCOUNT CBR CLASS A

The balance in Account 1580 RSVA WMS Sub-account CBR Class A is not proposed for disposition with this application; rather, it is settled with Class A customers in accordance with the OEB's Accounting Guidance on Capacity Based Recovery, issued on July 25, 2016.

1589 RSVA - GLOBAL ADJUSTMENT – CLASS A PORTION

Class A customers pay the actual Global Adjustment and the variance is due to minor rounding differences in amounts invoiced by the IESO, based on the PDF assigned to London Hydro, and what was billed to the customers using the customer specific PDF factor. The balance in

Account 1589 RSVA Global Adjustment for Class A customers (excluding “new Class A”) is immaterial and is not proposed for disposition with this application.

1575 IFRS-CGAAP TRANSITIONAL PP&E AMOUNTS AND 1576 ACCOUNTING CHANGES UNDER CGAAP

London Hydro requested to amortize $471,922 in Account 1575 IFRS-CGAAP Transitional PP&E Amounts over a four-year period in its 2013 COS rate application (EB-2012-0146). The Company received an approval to record and amortize the requested amount over the four-year period using Account 1576 Accounting Changes Under CGAAP commencing May 1, 2013, in the related Decision and Rate Order. The amortization period will expire on April 30, 2017.

The requested amount represents the adjustment to PP&E accounts as a result of London Hydro adopting revised extended lives and overhead capitalization policies (which are MIFRS-compliant) effective January 1, 2012. The balance of $471,922 is recovered from customers over a four-year period commencing May 1, 2013 as an increase to depreciation expense, in the same manner as Account 1575.

This deferral account is not subject to interest; no interest component is included in the balance.

While the respective amounts in depreciation for each affected year are reflected in the Fixed Asset Continuity Schedules under account 1576 Accounting Changes Under CGAAP, the amounts have been, inadvertently, reported in the trial balance under 1575 IFRS-CGAAP Transitional PP&E Amounts instead of 1576 Accounting Changes Under CGAAP.

London Hydro proposes the discontinuation accounts 1575 IFRS-CGAAP Transitional PP&E Amounts and 1576 Accounting Changes Under CGAAP after the four-year disposition period expired, April 30, 2017.

ACCOUNTS SUBMITTED FOR RECOVERY

Table 9-8 – Deferral and Variance Accounts Submitted for Recovery with this reflects the DVA balances in respect of which London Hydro is seeking disposition in this Application. The account balances are the audited amounts for December 31, 2015, and include carrying charges calculated to April 30, 2017 using the Board prescribed interest rates.

The balances, proposed for disposition before forecasted interest, are as presented in London Hydro's Audited Financial Statements as at December 31, 2015.

Adjustments made in 2016 to the December 31, 2015 balances of Accounts 1555 Sub-account Stranded Meter Costs and 1568 LRAM Variance Account are displayed in Table 9-8 – Deferral and Variance Accounts Submitted for Recovery. These adjustments are explained under the account description of both accounts.

London Hydro used the OEB's 2017 EDDVAR Continuity Schedule Work Form to allocate Group 1 and Group 2 DVA balances to customer classes and calculate the proposed rate riders, where the allocation methodology was accommodated by the model. Separate calculation is completed for the RSVA GA Class A balance and the RSVA WMS CBR Class B balance dispositions.

The Climate Change Projects disposition and rate rider calculation is completed in the ED Capital OMA Disposal Generator.

Table 9-8 – Deferral and Variance Accounts Submitted for Recovery with this Application

Deferral and Variance Accounts	Account	Principal Balance Dec 31, 2015	Interest to Dec 31, 2015	Total Balance Dec 31, 2015	Principal Transactions / Adjustments in 2016	Interest Transactions / Adjustments in 2016	Interest on Principal carried to Apr 30, 2016	Principal Disposition Apr 30, 2016	Interest Disposition Apr 30, 2016	Disposition Apr 30, 2016	Adjusted Principal Balance for Disposition Apr 30, 2017	2016 Interest Jan 1 to Dec 31 1.10%	2017 Interest Jan 1 to Apr 30 1.10%	Forecast Balance April 30, 2017
Group 1 Accounts														
Smart Metering Entity Charge Variance Account	1551	$ 55,739	$ 3,275	$ 59,014			$ 203	$ 80,290	$ 3,688	$ 83,978	$ (24,551)	$ 22	$ (89)	$ (25,031)
RSVA - Wholesale Market Service Charge	1580	$ (14,410,171)	$ (334,119)	$ (14,744,290)			$ (52,404)	$ (7,310,725)	$ (334,430)	$(7,645,155)	$ (7,099,446)	$ (104,680)	$ (25,675)	$ (7,229,490)
Variance WMS – Sub-account CBR Class B		$ 816,554	$ 2,724	$ 819,279						$ -	$ 816,554	$ 8,982	$ 2,953	$ 831,214
RSVA - Retail Transmission Network Charge	1584	$ 2,079,430	$ 80,110	$ 2,159,540			$ 7,562	$ 2,306,449	$ 90,691	$ 2,397,140	$ (227,019)	$ 5,890	$ (821)	$ (232,531)
RSVA - Retail Transmission Connection Charge	1586	$ 932,071	$ 47,042	$ 979,113			$ 3,390	$ 1,492,407	$ 54,283	$ 1,546,690	$ (560,336)	$ (736)	$ (2,026)	$ (570,339)
RSVA - Power	1588	$ (839,599)	$ 9,665	$ (829,934)			$ (3,053)	$ (467,081)	$ 2,326	$ (464,755)	$ (372,517)	$ (5,796)	$ (1,347)	$ (372,322)
RSVA - Global Adjustment Class B	1589	$ 8,376,856	$ 123,150	$ 8,500,006			$ 30,463	$ 9,143,276	$ 190,792	$ 9,334,068	$ (766,420)	$ 24,820	$ (2,772)	$ (812,014)
RSVA - Global Adjustment New Class A	1595	$ 751,969	$ 13,279	$ 765,247			$ 2,735	$ 479,011	$ 13,351	$ 492,362	$ 272,957	$ 4,745	$ 987	$ 278,617
Disposition and Recovery/Refund of Regulatory Balances (2012)	1595		$ (298,342)	$ (298,342)			$ -	$ -	$ (298,342)	$ (298,342)	$ -	$ -	$ -	$ -
Disposition and Recovery/Refund of Regulatory Balances (2013)	1595	$ (577,224)	$ 539,131	$ (38,093)			$ (2,099)	$ (577,224)	$ 537,032	$ (40,192)	$ -	$ (2,099)	$ -	$ -
Disposition and Recovery/Refund of Regulatory Balances (2014)	1595	$ 1,168	$ 3,633	$ 4,801						$ -	$ 1,168	$ 13	$ 4	$ 4,818
Group 2 Accounts														
Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	1508	$ 25,540	$ 744	$ 26,284							$ 25,540	$ 281	$ 92	$ 26,658
Retail Cost Variance Account - Retail	1518	$ 86,222	$ 1,672	$ 87,894							$ 86,222	$ 948	$ 312	$ 89,154
RCVASTR	1548	$ (91)	$ (69)	$ (160)							$ (91)	$ (1)	$ (0)	$ (161)
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs	1555	$ 1,162	$ 29,276	$ 30,438	$ 2,273	$ (2,229)					$ 3,434	$ 38	$ 12	$ 30,532
LRAM Variance Account	1568	$ 1,199,435	$ 16,028	$ 1,215,463	$ (758,283)	$ (14,221)					$ 441,153	$ 4,853	$ 1,618	$ 449,430
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592	$ (153,586)	$ (7,383)	$ (160,969)							$ (153,586)	$ (1,689)	$ (555)	$ (163,214)
Climate Change Projects														
Renewable Generation Connection Capital Deferral Account	1531	$ 6,222	$ 1,625	$ 7,848										
Renewable Generation Connection OM&A Deferral Account	1532	$ 142,954	$ 5,356	$ 148,311										
Smart Grid Capital Deferral Account	1534	$ 319,804	$ 6,026	$ 325,830										
Smart Grid OM&A Deferral Account	1535	$ 380,946	$ 8,126	$ 389,073										
Climate Change Projects Revenue Requirement														$ 654,165
		$ (804,596)	**$ 250,949**	**$ (553,647)**	**$ (756,010)**	**$ (16,450)**	**$ (13,204)**	**$ 5,146,404**	**$ 259,389**	**$ 5,405,794**	**$ (7,556,938)**	**$ (64,411)**	**$ (27,307)**	**$ (7,040,515)**

METHODS OF DISPOSITION OF DVA BALANCES

The following methods are proposed for disposition of the DVA balances for those accounts that have been selected for disposition, together with a summary of proposed rates.

GROUP ONE ACCOUNTS

Method of disposition: Allocation to rate classes on the basis of the forecasted 2017 kWh energy consumption by customer class and disposition through variable component rate rider based on kWh or kW.

Allocation of costs to customer classes is based upon kWh energy consumption by customer class in accordance with the default cost allocation methodology established by the Board for Group 1 deferral and variance accounts in the Electricity Distributor's Deferral and Variance Account Review Initiative (EDDVAR Report), dated July 31, 2009.

Certain rate riders are not applicable to all customers. London Hydro calculated four sets of rate riders based on the group of customers who contributed to the accumulated variance. The Deferral and Variance Account Work Form – Version 2.7 was used to calculate the Group 1 rate riders, except for Rate Rider for RSVA – Variance WMS – Sub-account CBR Class B. This rate rider was calculated outside of the 2017 EDDVAR Continuity Schedule Work Form as required.

Proposed method of disposition for Rate Rider for DVA Balances

Amount includes accounts 1551 Smart Metering Entity Charge Variance Account, 1584 RSVA Retail Transmission Network Charge, 1586 RSVA Retail Transmission Connection Charge, and 1595 Disposition and Recovery/Refund of Regulatory Balances residual balances. Balances of 1584 and 1586 accounts are allocated to rate classes on basis of the forecasted 2017 kWh energy consumption by customer. 1551 balances were allocated based on the number of customers in Residential and General Services less than 50 kW rate classes. 1595 residual balance is allocated to rate classes in proportion to the recovery share as established when rate riders were implemented. Disposition is proposed through variable component rate rider based on kWh or kW to all customers.

Proposed method of disposition for Rate Rider for DVA Balances to Non-WMP Customers

London Hydro has Wholesale Market Participants (WMP) in its customer base who settle energy and wholesale market service charges directly with the IESO. Therefore, variances accumulated in Accounts 1580 RSVA Wholesale Market Service Charges and 1588 RSVA Power should not be disposed to WMP customers. These balances are allocated to rate classes on the basis of the forecasted 2017 kWh energy consumption by non-WMP customers only. Disposition is proposed through variable component rate rider based on kWh or kW to non-WMP customers only.

Proposed method of disposition for Rate Rider for RSVA Global Adjustment

The amount proposed for disposition through this rate rider is accumulated in account 1589 RSVA Global Adjustment. Non-RPP non-WMP customers contributed to the variance and, therefore, this balance is allocated to rate classes on basis of the forecasted 2017 kWh energy consumption by non-RPP non-WMP customers only. Disposition is proposed through energy based rate rider (kWh) to non-RPP non-WMP customers only.

Proposed method of disposition for Rate Rider for RSVA WMS – Sub-account CBR Class B

The amount in account 1580 RSVA WMS Sub-account CBR Class B related to Class B customers only; therefore, this balance is allocated to rate classes on basis of the forecasted 2017 kWh energy consumption by Class B customers only. The 2017 EDDVAR Continuity Schedule Work Form does not accommodate the allocation methodology and rate rider calculation proposed here; therefore, this calculation was completed in a standalone Excel file named *2017 DVA Additional RR Calculation*. Table 9-9 – Billing Determinant and Balance Allocation for RSVA WMS – Sub-account CBR Class B reflects the proposed allocation methodology. The billing determinants for Class B customers are calculated by deducting the Class A and new Class A kWh and kW from the 2017 forecasted kWh and kW, respectively. The account balance is then allocated based on the kWh applicable to Class B customers only. Disposition is proposed through variable component rate rider based on kWh or kW to Class B customers only.

Table 9-9 – Billing Determinant and Balance Allocation for RSVA WMS – Sub-account CBR Class B

	A		B		C		D = A - B - C		
Rate Class	Total Metered kWh	Total Metered kW	Metered kWh for any Class A Customers in 2015 (partial or full year)	Metered kW for any Class A Customers in 2015 (partial or full year)	Metered kWh Consumption for New Class A customer(s) in the period prior to becoming Class A (i.e. Jan. 1 - June 30, 2015)	Metered kW Consumption for New Class A customer(s) in the period prior to becoming Class A (i.e. Jan. 1 - June 30, 2015)	Billing Determinants Class B kWh	Billing Determinants Class B kW	Allocated Amount of RSVA Variance WMS – Sub-account CBR Class B
RESIDENTIAL SERVICE CLASSIFICATION	1,068,671,798						1,068,671,798		$ 311,186
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION	371,911,863						371,911,863		$ 108,297
GENERAL SERVICE 50 TO 4,999 KW SERVICE CLASSIFICATION	1,469,047,930	3,778,018	48,842,761	184,298	33,089,331	73,642	1,387,115,838	3,520,078	$ 403,913
GENERAL SERVICE 1,000 TO 4,999 KW (CO-GENERATION) SERVICE CLASSIFICATION	10,203,354	65,844	6,258,933	31,212	2,767,899	23,639	1,176,521	10,993	$ 343
STANDBY POWER SERVICE CLASSIFICATION	23,988,201	154,800	16,632,696	77,400	7,355,506	77,400	-	-	$ -
LARGE USE SERVICE CLASSIFICATION	82,923,505	159,628	82,923,505	159,628			-	-	$ -
STREET LIGHTING SERVICE CLASSIFICATION	19,502,488	54,607					19,502,488	54,607	$ 5,679
SENTINEL LIGHTING SERVICE CLASSIFICATION	706,221	1,907					706,221	1,907	$ 206
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	5,464,035						5,464,035		$ 1,591
	3,052,419,395	**4,214,804**	**154,657,895**	**452,538**	**43,212,735**	**174,681**	**2,854,548,765**	**3,587,585**	**$ 831,214**

Proposed Direct Settlement for RSVA Global Adjustment - New Class A

London Hydro has six customers who elected to become a Class A as of July 1, 2015. These new Class A customers contributed to the balance accumulated in account 1589 RSVA Global Adjustment prior to that date. London Hydro analyzed these transactions as they are readily available. The transactions consist of the difference between the IESO charges at the final GA rate and the GA billed to the customer at the first estimate rate on the uplifted consumption kWh's. The new tab called *5a. GA_Allocation _Class A* in the 2017 EDDVAR Continuity Schedule Work Form calculates a $16,037 refund to the new Class A customers based on the percentage of new Class A consumption compared to the total Class B consumption. The balance of the applicable GA variance is $278,617 recovery from this group of customers based on the actual transactions. Due to the significant difference in the results, London Hydro proposes to settle the $278,617 through a 12-month equal adjustment to monthly bills, consistent with the EDDVAR Report. Calculations are included in file *2017 DVA Additional RR Calculations*.

London Hydro will continue the use of Retail Settlement Variance Accounts (RSVA's).

GROUP TWO AND OTHER ACCOUNTS

Proposed method of disposition for Rate Rider for Group 2 Accounts

Method of disposition: Allocation to rate classes on the basis of the forecasted 2017 kWh energy consumption by customer class and disposition through a fixed monthly rate rider based on the number of customers in the rate class.

Allocation of costs to customer classes of 1518 RCVA - Retail and 1548 RCVA - STR account balances is based on the number of customers in accordance with the default cost allocation methodology established by the Board in the EDDVAR Report, dated July 31, 2009.

Allocation of costs to customer classes of 1508 Other Regulatory Assets – Deferred IFRS Transition Costs, 1592 PILs and Tax Variances for 2006 and Subsequent Years, and 1592 PILs and Tax Variance for 2006 and Subsequent Years – Sub-Account HST/OVAT Input Tax Credits

(ITCs) balances is based upon kWh energy consumption by customer class for simplicity and consistency.

The residual balances in 1555 Smart Meter Capital and Recovery Offset Variance Sub-account – Stranded Meter Costs were directly allocated to Residential and General Service less than 50 kW rate classes from each respective class specific sub-accounts.

Disposition is proposed through a fixed monthly rate rider based on the number of customers in the rate class. Calculating the rate rider as a variable component based on kWh or kW would have resulted in no rate rider for most rate classes.

Proposed method of disposition for Rate Rider for Account 1568 LRAMVA

The allocated balances in 1568 LRAMVA for each rate class were calculated in the OEB issued LRAMVA Work Form and entered in the Billing Determinants schedule in the 2017 EDDVAR Continuity Schedule Work Form for rate rider calculation. Disposition is proposed through variable component rate rider based on kWh or kW to all customers.

The continuity schedule for all DVA's submitted for disposition, the cost allocation and rate rider derivation are included in 2017 EDDVAR Continuity Schedule COS latest model and included in Appendix 9A.

The Excel file, named *2017 DVA Additional RR Calculation*, containing the additional calculations related to the disposition of 1580 RSVA WMS CBR Class B and 1589 RSVA GA New Class A portion is also included with this application.

CLIMATE CHANGE PROJECTS

Method of disposition: Allocation of revenue requirement to rate classes on the basis of the forecasted 2017 number of customers (excluding connections) by customer class, and disposition through a fixed monthly rate rider based on the number of customers in the rate class.

The calculation of revenue requirement, the cost allocation and rate rider derivation are included in ED Capital & OM&A Disposal Generator model and included in Appendix 9C.

PROPOSED RATE RIDERS

The proposed rates that result from the disposal of the DVA balances, as requested, are set out in the tables below. The tables provide rate riders that would apply with an effective date of May 1, 2017.

Rate riders calculated for the period commencing May 1, 2017 are based on a 12-month disposition period.

Although the delivery component of the bill is a rather small part of the total electricity bill, London Hydro proposes the one-year disposition period to assist its customers with the overall cost of electricity.

GROUP ONE ACCOUNTS

Proposed Rate Rider for Deferral / Variance Accounts Balances (excluding Global Adj.)

This rate rider is applicable to all customers and is proposed through variable component rate rider based on kWh or kW.

Table 9-10 – Rate Rider Calculation for DVA Balances

Rate Class (Enter Rate Classes in cells below)	Units	kW / kWh / # of Customers	Allocated Balance (excluding 1589)	Rate Rider for Deferral/Variance Accounts
RESIDENTIAL SERVICE CLASSIFICATION	kWh	1,068,671,798	-$ 302,042	- 0.0003
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION	kWh	371,911,863	-$ 99,300	- 0.0003
GENERAL SERVICE 50 TO 4,999 KW SERVICE CLASSIFICATION	kW	3,778,018	-$ 384,184	- 0.1017
GENERAL SERVICE 1,000 TO 4,999 KW (CO-GENERATION) SERVICE CLASSIFICATION	kW	65,844	-$ 2,684	- 0.0408
STANDBY POWER SERVICE CLASSIFICATION	kW	154,800	-$ 6,310	- 0.0408
LARGE USE SERVICE CLASSIFICATION	kW	159,628	-$ 21,811	- 0.1366
STREET LIGHTING SERVICE CLASSIFICATION	kW	54,607	-$ 5,130	- 0.0939
SENTINEL LIGHTING SERVICE CLASSIFICATION	kW	1,907	-$ 186	- 0.0974
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	kWh	5,464,035	-$ 1,437	- 0.0003
		-	$ -	-
		-	$ -	-
Total			**-$ 823,083**	

Proposed Rate Rider for Deferral / Variance Accounts Balances Non-WMP

This rate rider is applicable to non-WMP customers only and is proposed through variable component rate rider based on kWh or kW.

Table 9-11 – Rate Rider Calculation for DVA Balances to Non-WMP Customers

Rate Class (Enter Rate Classes in cells below)	Units	kW / kWh / # of Customers	Allocated Balance (excluding 1589)	Rate Rider for Deferral/Variance Accounts
RESIDENTIAL SERVICE CLASSIFICATION	kWh	1,068,671,798	-$ 2,661,444	- 0.0025
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION	kWh	371,911,863	-$ 926,218	- 0.0025
GENERAL SERVICE 50 TO 4,999 KW SERVICE CLASSIFICATION	kW	3,746,072	-$ 3,658,550	- 0.9766
GENERAL SERVICE 1,000 TO 4,999 KW (CO-GENERATION) SERVICE CLASSIFICATION	kW	65,844	-$ 25,411	- 0.3859
STANDBY POWER SERVICE CLASSIFICATION	kW	154,800	-$ 59,741	- 0.3859
LARGE USE SERVICE CLASSIFICATION	kW	159,628	-$ 206,515	- 1.2937
STREET LIGHTING SERVICE CLASSIFICATION	kW	54,607	-$ 48,569	- 0.8894
SENTINEL LIGHTING SERVICE CLASSIFICATION	kW	1,907	-$ 1,759	- 0.9223
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	kWh	5,464,035	-$ 13,608	- 0.0025
		-	$ -	-
		-	$ -	-
Total			**-$ 7,601,813**	

Proposed Rate Rider for RSVA Global Adjustment

This rate rider is applicable to non-RPP non-WMP customers only and is proposed through energy based rate rider based on kWh.

Table 9-12 – Rate Rider Calculation for RSVA Global Adjustment

Rate Class (Enter Rate Classes in cells below)	Units	kWh	Balance of RSVA - Power - Global Adjustment	Rate Rider for RSVA - Power - Global Adjustment
RESIDENTIAL SERVICE CLASSIFICATION	kWh	62,268,991	-$ 35,768	- 0.0006
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION	kWh	62,326,448	-$ 35,801	- 0.0006
GENERAL SERVICE 50 TO 4,999 KW SERVICE CLASSIFICATION	kWh	1,268,249,874	-$ 728,497	- 0.0006
GENERAL SERVICE 1,000 TO 4,999 KW (CO-GENERATION) SERVICE CLASSIFICATION	kWh	1,176,521	-$ 676	- 0.0006
STANDBY POWER SERVICE CLASSIFICATION	kWh	-	$ -	-
LARGE USE SERVICE CLASSIFICATION	kWh	-	$ -	-
STREET LIGHTING SERVICE CLASSIFICATION	kWh	19,502,488	-$ 11,202	- 0.0006
SENTINEL LIGHTING SERVICE CLASSIFICATION	kWh	18,632	-$ 11	- 0.0006
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	kWh	102,372	-$ 59	- 0.0006
	kWh	-	$ -	-
		-	$ -	-
Total			**-$ 812,013**	

Proposed Rate Rider for RSVA WMS Sub-account CBR Class B

This rate rider is applicable to Class B customers only and is proposed through variable component rate rider based on kWh or kW.

Table 9-13 – Rate Rider Calculation for RSVA Variance WMS – Sub-account CBR Class B

Rate Class (Enter Rate Classes in cells below)	Units	kW / kWh / # of Customers	Balance of CBR Class B	Rate Rider for WMS CBR Class B
RESIDENTIAL SERVICE CLASSIFICATION	kWh	1,068,671,798	$ 311,186	**0.0003**
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION	kWh	371,911,863	$ 108,297	**0.0003**
GENERAL SERVICE 50 TO 4,999 KW SERVICE CLASSIFICATION	kW	3,520,078	$ 403,913	**0.1147**
GENERAL SERVICE 1,000 TO 4,999 KW (CO-GENERATION) SERVICE CLASSIFICATION	kW	10,993	$ 343	**0.0312**
STANDBY POWER SERVICE CLASSIFICATION	kW	-	$ -	**-**
LARGE USE SERVICE CLASSIFICATION	kW	-	$ -	**-**
STREET LIGHTING SERVICE CLASSIFICATION	kW	54,607	$ 5,679	**0.1040**
SENTINEL LIGHTING SERVICE CLASSIFICATION	kW	1,907	$ 206	**0.1078**
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	kWh	5,464,035	$ 1,591	**0.0003**
Total			**$ 831,214**	

Proposed Direct Settlement for RSVA Global Adjustment – New Class A

London Hydro proposes to settle the $278,617 RSVA Global Adjustment related to new Class A customers through a 12-month equal adjustment to monthly bills, consistent with the EDDVAR Report. If any of the affected customers express a clear preference for a one-time settlement, London Hydro will accommodate such request.

Table 9-14 – Proposed Direct Settlement for RSVA GA – New Class A

New Class A customers	RSVA GA Principal Amount	RSVA GA Interest	RSVA GA Total Amount	Monthly Adjustments
Customer 4	$ 63,815.80	$ 1,307.01	$ 65,122.81	$ 5,426.90
Customer 5	$ 55,979.27	$ 1,121.53	$ 57,100.80	$ 4,758.40
Customer 6	$ 75,752.22	$ 1,645.54	$ 77,397.76	$ 6,449.81
Customer 7	$ 8,316.57	$ 173.26	$ 8,489.83	$ 707.49
Customer 8	$ 17,253.37	$ 374.07	$ 17,627.44	$ 1,468.95
Customer 9	$ 51,840.01	$ 1,038.67	$ 52,878.68	$ 4,406.56
Total	**$ 272,957.24**	**$ 5,660.07**	**$ 278,617.31**	

GROUP TWO AND OTHER ACCOUNTS

Proposed Rate Rider for Group 2 Accounts

This rate rider is applicable to all customers and is proposed through a fixed monthly rate rider based on the number of customers in the rate class.

Table 9-15 –Rate Rider Calculation for Group 2 Accounts

Rate Class (Enter Rate Classes in cells below)	Units	# of Customers	Balance of Group 2 Accounts	Rate Rider for Group 2 Accounts
RESIDENTIAL SERVICE CLASSIFICATION	# of Customers	142,509	$ 11,124	$ 0.01
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION	# of Customers	12,749	-$ 3,040	-$ 0.02
GENERAL SERVICE 50 TO 4,999 KW SERVICE CLASSIFICATION	# of Customers	1,561	-$ 22,891	-$ 1.22
GENERAL SERVICE 1,000 TO 4,999 KW (CO-GENERATION) SERVICE CLASSIFICATION	# of Customers	4	-$ 159	-$ 3.31
STANDBY POWER SERVICE CLASSIFICATION	# of Customers	3	-$ 374	-$ 10.38
LARGE USE SERVICE CLASSIFICATION	# of Customers	1	-$ 1,292	-$ 107.68
STREET LIGHTING SERVICE CLASSIFICATION	# of Customers	35,912	-$ 304	-$ 0.00
SENTINEL LIGHTING SERVICE CLASSIFICATION	# of Customers	599	-$ 11	-$ 0.00
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	# of Customers	1,537	-$ 85	-$ 0.00
		-	$ -	$ -
		-	$ -	$ -
Total			**-$ 17,031**	

Proposed Rate Rider for Account 1568 LRAMVA

This rate rider is applicable to all customers and is proposed through variable component rate rider based on kWh or kW.

Table 9-16 – Rate Rider Calculation for Account 1568 LRAMVA

Rate Class (Enter Rate Classes in cells below)	Units	kW / kWh / # of Customers	Balance of Account 1568	Rate Rider for Account 1568
RESIDENTIAL SERVICE CLASSIFICATION	kWh	1,068,671,798	$ 91,371	**0.0001**
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION	kWh	371,911,863	$ 284,131	**0.0008**
GENERAL SERVICE 50 TO 4,999 KW SERVICE CLASSIFICATION	kW	3,778,018	$ 169,775	**0.0449**
GENERAL SERVICE 1,000 TO 4,999 KW (CO-GENERATION) SERVICE CLASSIFICATION	kW	65,844	-$ 10,554	**- 0.1603**
STANDBY POWER SERVICE CLASSIFICATION	kW	154,800	-$ 24,813	**- 0.1603**
LARGE USE SERVICE CLASSIFICATION	kW	159,628	-$ 33,978	**- 0.2129**
STREET LIGHTING SERVICE CLASSIFICATION	kW	54,607	-$ 22,143	**- 0.4055**
SENTINEL LIGHTING SERVICE CLASSIFICATION	kW	1,907	-$ 950	**- 0.4982**
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	kWh	5,464,035	-$ 3,410	**- 0.0006**
		-	$ -	**-**
		-	$ -	**-**
Total			**$ 449,430**	

CLIMATE CHANGE PROJECTS

Proposed Rate Rider for Climate Change Projects

This rate rider is applicable to customers excluding connections and is proposed through a fixed monthly rate rider based on the number of customers in the rate class.

Table 9-17 – Rate Rider Calculation for Account Climate Change Projects

Rate Rider Start Date	May 1, 2017			
Rate Rider End Date	April 30, 2018			
Number of Months	12			
Customer Class	**Number of Customers**	**IRR Allocation**	**Disposition Recovery**	**Monthly Rate Rider**
RESIDENTIAL	142,509	90.9%	$ 594,453	**$ 0.35**
GENERAL SERVICE LESS THAN 50 kW	12,749	8.1%	$ 53,180	**$ 0.35**
GENERAL SERVICE 50 TO 4,999 KW SERVICE CLASSIFICATION	1,561	1.0%	$ 6,511	**$ 0.35**
GENERAL SERVICE 1,000 TO 4,999 KW (CO-GENERATION) SERVICE CLASSIFICATION	4	0.0%	$ 17	**$ 0.35**
STANDBY POWER SERVICE CLASSIFICATION	-	0.0%	$ -	**$ -**
LARGE USE SERVICE CLASSIFICATION	1	0.0%	$ 4	**$ 0.35**
STREET LIGHTING SERVICE CLASSIFICATION	35,912	0.0%	$ -	**$ -**
SENTINEL LIGHTING SERVICE CLASSIFICATION	599	0.0%	$ -	**$ -**
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	1,537	0.0%	$ -	**$ -**
Total	194,872	100.0%	$ 654,165	

REQUEST FOR APPROVAL OF THE USE OF NEW VARIANCE ACCOUNTS

RETIREE LIFE INSURANCE

London Hydro is requesting the addition of a new deferral account, “Retiree Life Insurance.”

As mentioned in Exhibit 4, Section Consolidated Cost Elements, Pages 351 to 354 (Employee Benefits), London Hydro currently pays life insurance premiums on behalf of a large group of retirees associated with a plan that is no longer offered. As there are no new retirees being added to this plan, the annual premiums continue to increase significantly. The difference between the expected cost of premiums and the amounts to be recovered from 2017-2021, based on this COS Application, is $486,417. This difference is substantial and, accordingly, the Company is requesting the creation of a deferral account to record the difference.

The new deferral account will be used to record all premiums and potential buyouts paid regarding life insurance benefits, offset by the annual amount recovered through rates. The difference will remain in the newly created deferral account, to be collected or repaid by London Hydro at a later time through rates.

In the meantime, London Hydro is taking steps to try to reduce the costs relating to this group of retirees and is looking into the following options:

- Utilizing the services of a third party plan administrator, who can manage the fund and the payouts to the estates. The Company would pay an administrative fee paid to the selected insurance company to manage the “refund accounting underwriting arrangement”.
- Offering buyouts to the group of retirees, allowing them to take a lump-sum payment upfront and foregoing the payout to their estate upon death.

The Company decided that a deferral account is appropriate due to:

- the substantial unfunded cost that London Hydro is anticipating

- the volatility and unpredictable pattern of the potential payouts
- the unpredictability of member uptake regarding potential payouts
- the difficulty finding a plan administrator for the "refund accounting underwriting arrangement"

This deferral account has no balance for the purpose of this Rate Application. It is intended for future use, and accordingly, no carrying charges have been applied to this account and there is no impact on revenue requirement as filed in this Application as a result of this request.

PENSION & OTHER POST-EMPLOYMENT BENEFITS (P&OPEB)

The Ontario Energy Board (OEB) is undertaking a consultation on the regulatory treatment of pensions and other post-employment benefit (P&OPEB) costs (Board File Number EB-2015-0040). The objective of this consultation is to consider mechanisms for the rate-regulated treatment of P&OPEB costs.

Notwithstanding the results of this consultation, London Hydro is requesting the creation of a deferral account to record adjustments made upon transition from CGAAP to IFRS in connection with unamortized actuarial gains and losses, and past service awards not recognized under CGAAP as well as actuarial gains and losses resulting during 2014 and 2015 as follows.

Table 9-18 – P&OPEB IFRS Transitional

P&OPEB IFRS Transitional Adjustments		
Transitional Adjustments January 1, 2014		
Unamortized actuarial losses	$ 1,162,200	
Past service awards (not recognized under CGAAP)	93,700	1,255,900
Actuarial loss for 2014		471,400
Actuarial gain for 2015		(178,700)
		$ 1,548,600

London Hydro makes this request for the recovery of the above without prejudice to the final outcome of the above noted consultation.

On February 13, 2008, the Canadian Accounting Standards Board (AcSB) officially confirmed the requirement for publicly accountable enterprises to adopt IFRS for financial reporting purposes in 2011. However, transition was deferred due to issues surrounding rate-regulated accounting for regulatory assets and liabilities. London Hydro's eventual and actual transition date to IFRS is January 1, 2015 with 2014 amounts being restated for comparative purposes.

Transitional adjustments made on January 1, 2014 to restate CGAAP balance sheet amounts to IFRS include a debit adjustment in the amount of $1,255,900 to retained earnings representing $1,162,200 in unamortized actuarial losses and a past service awards liability of $93,700 which is not a requirement under CGAAP. Further, during the fiscal years ended December 31, 2014 and December 31, 2015, an actuarial loss of $471,400 and actuarial gain of $178,700 (respectively) were recognized and recorded through Other Comprehensive Income in the total net amount of $292,700.

No carrying charges have been applied to this account and there is no impact on the revenue requirement as filed in this Application as a result of these transitional adjustments or recognition of actuarial gains and losses.

OEB Appendix 2-KA OPEBs (Other Post-Employment Benefits) Costs has been provided in the Cost of Service Rate Application in Exhibit 4.

CAP AND TRADE DEFERRAL ACCOUNT

For brevity, London Hydro is herein requesting the establishment of the same Cap and Trade Deferral Account as requested by Brantford Power Inc. EB-2016-0058 Exhibit 9 Tab 1 Schedule 1 Page 1 as Filed May 4, 2016. London Hydro supports Brantford Power's justification for the establishment of this deferral account.

CLIMATE CHANGE ACTION PLAN DEFERRAL ACCOUNT

The government of Ontario launched its Climate Change Action Plan in June 2016, establishing a five-year framework expected to help fight climate change through the reduction of greenhouse gas emissions. The framework provides Ontario homes and businesses with tools and incentives to accelerate the use of cleaner technology. The government intends to invest the proceeds from the newly launched Ontario Cap and Trade program into projects supporting the Action Plan.

London Hydro has reviewed the deliverables prescribed under the Climate Change Action Plan and is concerned that there will be potential increased cost to be incurred. Top of mind is the potential cost to be incurred in implementing the delivery mechanism for a four-year initiative to provide free overnight electric vehicle charging to residential and multi-unit residential customers.

More importantly, London Hydro has concerns with respect to the potential pace of conversion to electric vehicles and its impact on our current electric infrastructure, primarily in residential neighbourhoods. Current residential subdivision design expects average demand for a household to be 2 kW. Normally a 20 kVA transformer is installed to service 10 homes. Potentially the addition of a single car charger to a single residential will add an additional draw of 4 kW. With some natural redundancy the addition of one to three charging units to each transformer may not be an issue. More than this has the potential to overburden the circuit affecting all customers serviced by that transformer. The solution will be to upgrade the transformers and potential the electrical service. London Hydro is concerned that it will be required to invest in unplanned infrastructure transformer upgrades and affected services. Such costs have not been built in to our proposed capital plans, nor could such cost be reasonably included based on our inability to forecast the potential uptake on electric vehicle conversion.

This issue is not only isolated to residential subdivisions, as the commercial sector will have similar concerns as well. However, commercial services may be relieved by the OEB Distribution System Code and London Hydro's Conditions of Service applications with respect to service upgrades.

Hence, London Hydro is herein requesting the establishment of a deferral account to be applied to unplanned infrastructure transformer upgrades, electrical system upgrades, and other such costs incurred when directly related to the Climate Change Action Plan and not directly reimbursed in full by customer contributions or other subsidies.

As an alternative, should the deferral account request be denied, London Hydro would herein request to have its Electricity Distribution Licence amended to affect the application of customers contributions on residential service changes as a result of activities directly related to the Climate Change Action Plan.

BURDEN REDUCTION BILL DEFERRAL ACCOUNT

London Hydro is aware that the OEB has requested amendments to the Burden Reduction Bill, Bill 218, which would give the OEB more authority over how electricity utilities exercise their right to disconnect for nonpayment. If passed, and as currently worded, Bill 218 would allow the OEB to make rules setting out periods when an electricity utility cannot disconnect a residential or small business consumer.

London Hydro is concerned with respect to the impact of such change and its potential effect of escalating Bad Debt Write-offs. London Hydro has experienced the effects of elongated periods wherein extended disconnection moratoriums have resulted in escalated Bad Debt Write-offs. London Hydro prides itself of exercising the OEB's current direction on disconnection as mandated by the existing distribution system plan. London Hydro believes it currently assumes a normal bad debt experience and is fairly compensated by the OEB in assuming that risk within the current deemed return on equity provision in a Cost of Service application. However it is London Hydro's concern that the rising amounts charged on electricity bills, mostly due to increased consumption costs beyond London Hydro's control, is placing heavier burden on low volume consumers' ability to meet their debt obligations. London Hydro has observed an increased volume of disconnection notices being issued while exercising current OEB prescribed disconnection policy already. London Hydro believes that if mandated to exercise longer periods before effecting disconnection, its bad debt write off amounts will escalate substantially beyond current levels.

Hence, London Hydro herein requests the establishment of a deferral account to recover amounts in excess of one and one half times the average bad debt write-off amounts experience in the three preceding years should Bill 218 be enacted as worded and should the OEB exercise the elongation of disconnection periods in excess of currently prescribed periods.

ENERGY SALES AND COST OF POWER

The sale of energy is a flow through revenue and the cost of power is a flow through expense. Energy sales and the cost of power expense by component are presented in Table 9-19 – Cost of Power and Table 9-20 – Energy Sales respectively, as reported in the audited financial statements and the trial balance by Uniform System of Accounts. London Hydro has no profit or loss resulting from the flow through energy revenues and expenses. Any temporary variances are included in the RSVA balances.

London Hydro calculated the cost of power for the 2016 Bridge Year and 2017 Test Year based on the results of the load forecast discussed in detail in Exhibit 3. The commodity prices used in the calculation were prices published in the Board's Regulated Price Plan Report – May 1, 2016 to April 30, 2017, issued April 14, 2016. Should the Board publish a revised Regulated Price Plan Report prior to the Decision, London Hydro will update the electricity prices in the forecast.

The detailed calculation of the Cost of Power for 2016 Bridge Year and 2017 Test Year is included in Exhibit 6 Tab 1 Schedule 1.

Table 9-19 – Cost of Power

Cost of Power Purchased		2013 Actual	2014 Actual	2015 Actual	2016 Bridge Year	2017 Test Year
4705	Power Purchased	$ 176,942,895	$ 202,654,655	$ 193,710,506	$ 204,585,809	$ 199,767,002
4707	Global Adjustment	104,539,562	98,388,800	131,215,376	148,213,032	144,722,028
4708	Charges WMS	17,225,072	18,167,833	12,383,496	15,819,661	18,884,186
4714	Charges NW	23,349,588	24,025,783	22,788,040	22,903,953	18,270,488
4716	Charges CN	18,037,125	18,745,859	18,426,305	19,125,219	16,124,013
4751	Smart Metering Entity Charge	1,041,340	1,401,273	1,412,853	1,427,251	1,471,846
		$ 341,135,582	**$ 363,384,203**	**$ 379,936,576**	**$ 412,074,924**	**$ 399,239,563**

Table 9-20 – Energy Sales

Energy Costs Billed		2013 Actual	2014 Actual	2015 Actual	2016 Bridge Year	2017 Test Year
4006	Residential Energy Sales	$ (85,167,166)	$ (95,473,020)	$ (104,172,576)	$ (116,056,541)	$ (113,623,782)
4020	Energy Sales to Large Users	(13,118,412)	(13,777,050)	(12,488,388)	(11,254,296)	(9,268,658)
4025	Street Lighting Energy Sales	(1,998,943)	(2,187,895)	(2,351,895)	(2,741,249)	(2,201,850)
4030	Sentinel Lighting Energy Sales	(62,385)	(65,931)	(70,213)	(76,497)	(78,145)
4035	General Service Energy Sales	(140,640,390)	(153,557,726)	(166,551,539)	(184,638,516)	(181,867,042)
4050	Revenue Adjustment	(8,059,858)	(4,575,086)	(4,982,251)		
4055	Energy Sales for Resale	(32,435,304)	(31,406,748)	(34,309,020)	(38,031,741)	(37,449,553)
4062	Billed WMS	(17,225,071)	(18,167,833)	(12,383,496)	(15,819,661)	(18,884,186)
4066	Billed NW	(23,349,588)	(24,025,783)	(22,788,040)	(22,903,953)	(18,270,488)
4068	Billed CN	(18,037,125)	(18,745,859)	(18,426,305)	(19,125,219)	(16,124,013)
4751	Billed - Smart Metering Entity Char	(1,041,340)	(1,401,273)	(1,412,853)	(1,427,251)	(1,471,846)
		$ (341,135,581)	**$ (363,384,203)**	**$ (379,936,576)**	**$ (412,074,924)**	**$ (399,239,563)**

APPENDIX 1 OF 5
APPENDIX 9A DEFERRAL AND VARIANCE ACCOUNTS CONTINUITY SCHEDULE AND RATE RIDER CALCULATION

Ontario Energy Board

2017 Deferral/Variance Account Workform

Version 2.8

Utility Name	London Hydro Inc.
Service Territory	London
Assigned EB Number	EB-2016-0091
Name of Contact and Title	Martin Benum
Phone Number	519-661-5800 X 5750
Email Address	benumm@londonhydro.com

General Notes

Notes

Pale green cells represent input cells.

Pale blue cells represent drop-down lists. The applicant should select the appropriate item from the drop-down list.

White cells contain fixed values, automatically generated values or formulae.

2010

Account Descriptions	Account Number	Opening Principal Amounts as of Jan-1-10	Transactions[1] Debit/ (Credit) during 2010	OEB-Approved Disposition during 2010	Principal Adjustments[2] during 2010	Closing Principal Balance as of Dec-31-10	Opening Interest Amounts as of Jan-1-10	Interest Jan-1 to Dec-31-10	OEB-Approved Disposition during 2010	Interest Adjustments[1] during 2010	Closing Interest Amounts as of Dec-31-10
Group 1 Accounts											
LV Variance Account	1550					$0					$0
Smart Metering Entity Charge Variance Account	1551										
RSVA - Wholesale Market Service Charge[10]	1580	-$639,178	-$3,729,866			-$4,369,044	-$2,623	-$20,236			-$22,859
Variance WMS – Sub-account CBR Class A[10]	1580										
Variance WMS – Sub-account CBR Class B[10]	1580										
RSVA - Retail Transmission Network Charge	1584	$339,095	$195,481			$534,576	$106	$3,363			$3,469
RSVA - Retail Transmission Connection Charge	1586	-$440,008	-$160,567			-$600,575	-$1,858	-$4,872			-$6,730
RSVA - Power (excluding Global Adjustment)	1588	-$1,639,173	-$40,397			-$1,679,570	-$42,015	-$44,118			-$86,133
RSVA - Global Adjustment	1589	$1,146,005	-$2,423,012			-$1,277,007	-$11,505	-$2,645			-$14,150
Disposition and Recovery/Refund of Regulatory Balances (2009)[8]	1595					$0					$0
Disposition and Recovery/Refund of Regulatory Balances (2010)[8]	1595					$0					$0
Disposition and Recovery/Refund of Regulatory Balances (2011)[8]	1595					$0					$0
Disposition and Recovery/Refund of Regulatory Balances (2012)[8]	1595					$0					$0
Disposition and Recovery/Refund of Regulatory Balances (2013)[8]	1595					$0					$0
Disposition and Recovery/Refund of Regulatory Balances (2014)[8]	1595					$0					$0
Disposition and Recovery/Refund of Regulatory Balances (2015)[8]	1595					$0					$0
Not to be disposed of unless rate rider has expired and balance has been audited											
Group 1 Sub-Total (including Account 1589 - Global Adjustment)		-$1,233,259	-$6,158,361	$0	$0	-$7,391,620	-$57,895	-$68,508	$0	$0	-$126,403
Group 1 Sub-Total (excluding Account 1589 - Global Adjustment)		-$2,379,264	-$3,735,349	$0	$0	-$6,114,613	-$46,390	-$65,863	$0	$0	-$112,253
RSVA - Global Adjustment	**1589**	$1,146,005	-$2,423,012	$0	$0	-$1,277,007	-$11,505	-$2,645	$0	$0	-$14,150
Group 2 Accounts											
Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	1508	$135,327	$139,434			$274,760	$72	$1,905			$1,977
Other Regulatory Assets - Sub-Account - Incremental Capital Charges	1508					$0					$0
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act[3]	1508										
Other Regulatory Assets - Sub-Account - Other [4]	1508					$0					$0
Retail Cost Variance Account - Retail	1518	-$39,087	-$15,876			-$54,963	-$128	-$380			-$508
Misc. Deferred Debits	1525					$0					$0
Retail Cost Variance Account - STR	1548	$30,243	$26,397			$56,640	$99	$357			$456
Board-Approved CDM Variance Account	1567					$0					$0
Extra-Ordinary Event Costs	1572					$0					$0
Deferred Rate Impact Amounts	1574					$0					$0
RSVA - One-time	1582					$0					$0
Other Deferred Credits	2425					$0					$0
Group 2 Sub-Total			$149,955	$0	$0	$276,437	$43	$1,882	$0	$0	$1,925
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)	1592					$0					$0
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592		-$57,782			-$57,782		-$138			-$138
Total of Group 1 and Group 2 Accounts (including 1592)		-$1,233,259	-$6,066,188	$0	$0	-$7,172,965	-$57,852	-$66,764	$0	$0	-$124,616
LRAM Variance Account[12]	**1568**					$0					$0

Account Descriptions	Account Number	2010									
		Opening Principal Amounts as of Jan-1-10	Transactions[1] Debit / (Credit) during 2010	OEB-Approved Disposition during 2010	Principal Adjustments[2] during 2010	Closing Principal Balance as of Dec-31-10	Opening Interest Amounts as of Jan-1-10	Interest Jan-1 to Dec-31-10	OEB-Approved Disposition during 2010	Interest Adjustments[1] during 2010	Closing Interest Amounts as of Dec-31-10
Total including Account 1568			-$6,066,188	$0	$0	-$7,172,965	-$57,852	-$66,764	$0	$0	-$124,616
Renewable Generation Connection Capital Deferral Account[9]	1531					$0					$0
Renewable Generation Connection OM&A Deferral Account[9]	1532					$0					$0
Renewable Generation Connection Funding Adder Deferral Account	1533					$0					$0
Smart Grid Capital Deferral Account	1534					$0					$0
Smart Grid OM&A Deferral Account	1535					$0					$0
Smart Grid Funding Adder Deferral Account	1536					$0					$0
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital[5]	1555					$0					$0
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries[5]	1555					$0					$0
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs[5]	1555	$118,378	$2,955,316			$3,073,694					$0
Smart Meter OM&A Variance[5]	1556					$0					$0
Meter Cost Deferral Account (MIST Meters)[11]	1557										
IFRS-CGAAP Transition PP&E Amounts Balance + Return Component[6]	1575										
Accounting Changes Under CGAAP Balance + Return Component[6]	1576										

Account Descriptions	Account Number	2011 Opening Principal Amounts as of Jan-1-11	Transactions[1] Debit / (Credit) during 2011	OEB-Approved Disposition during 2011	Principal Adjustments[2] during 2011	Closing Principal Balance as of Dec-31-11	Opening Interest Amounts as of Jan-1-11	Interest Jan-1 to Dec-31-10	OEB-Approved Disposition during 2011	Interest Adjustments[2] during 2011	Closing Interest Amounts as of Dec-31-11
Group 1 Accounts											
LV Variance Account	1550	$0				$0	$0				$0
Smart Metering Entity Charge Variance Account	1551										
RSVA - Wholesale Market Service Charge[10]	1580	-$4,369,044	-$3,892,865			-$8,261,909	-$22,859	-$92,786			-$115,645
Variance WMS – Sub-account CBR Class A[10]	1580										
Variance WMS – Sub-account CBR Class B[10]	1580										
RSVA - Retail Transmission Network Charge	1584	$534,576	$239,439			$774,015	$3,469	$8,508			$11,977
RSVA - Retail Transmission Connection Charge	1586	-$600,575	$320,801			-$279,774	-$6,730	-$10,689			-$17,419
RSVA - Power (excluding Global Adjustment)	1588	-$1,679,570	-$2,217,235			-$3,896,805	-$86,133	-$107,643			-$193,776
RSVA - Global Adjustment	1589	-$1,277,007	-$1,335,747			-$2,612,754	-$14,150	$41,830			$27,680
Disposition and Recovery/Refund of Regulatory Balances (2009)[8]	1595	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2010)[8]	1595	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2011)[8]	1595	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2012)[8]	1595	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2013)[8]	1595	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2014)[8]	1595	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2015)[8]	1595	$0				$0	$0				$0
Not to be disposed of unless rate rider has expired and balance has been audited											
Group 1 Sub-Total (including Account 1589 - Global Adjustment)		-$7,391,620	-$6,885,607	$0	$0	-$14,277,227	-$126,403	-$160,780	$0	$0	-$287,183
Group 1 Sub-Total (excluding Account 1589 - Global Adjustment)		-$6,114,613	-$5,549,860	$0	$0	-$11,664,473	-$112,253	-$202,610	$0	$0	-$314,863
RSVA - Global Adjustment	**1589**	-$1,277,007	-$1,335,747	$0	$0	-$2,612,754	-$14,150	$41,830	$0	$0	$27,680
Group 2 Accounts											
Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	1508	$274,760	$74,263			$349,024	$1,977	$4,673			$6,650
Other Regulatory Assets - Sub-Account - Incremental Capital Charges	1508	$0				$0	$0				$0
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act[3]	1508	$0				$0	$0				$0
Other Regulatory Assets - Sub-Account - Other [4]	1508	$0				$0	$0				$0
Retail Cost Variance Account - Retail	1518	-$54,963	-$27,290			-$82,253	-$508	-$1,023			-$1,531
Misc. Deferred Debits	1525	$0				$0	$0				$0
Retail Cost Variance Account - STR	1548	$56,640	$30,096			$86,736	$456	$1,032			$1,488
Board-Approved CDM Variance Account	1567	$0				$0	$0				$0
Extra-Ordinary Event Costs	1572	$0				$0	$0				$0
Deferred Rate Impact Amounts	1574	$0				$0	$0				$0
RSVA - One-time	1582	$0				$0	$0				$0
Other Deferred Credits	2425	$0				$0	$0				$0
Group 2 Sub-Total		$276,437	$77,069	$0	$0	$353,507	$1,925	$4,682	$0	$0	$6,607
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)	1592	$0				$0	$0				$0
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592	-$57,782	-$127,764			-$185,546	-$138	-$1,714			-$1,852
Total of Group 1 and Group 2 Accounts (including 1592)		-$7,172,965	-$6,936,302	$0	$0	-$14,109,266	-$124,616	-$157,812	$0	$0	-$282,428
LRAM Variance Account[12]	**1568**	$0				$0	$0				$0

Account Descriptions	Account Number	2011									
		Opening Principal Amounts as of Jan-1-11	Transactions[1] Debit/ (Credit) during 2011	OEB-Approved Disposition during 2011	Principal Adjustments[2] during 2011	Closing Principal Balance as of Dec-31-11	Opening Interest Amounts as of Jan-1-11	Interest Jan-1 to Dec-31-10	OEB-Approved Disposition during 2011	Interest Adjustments[2] during 2011	Closing Interest Amounts as of Dec-31-11
Total including Account 1568		-$7,172,965	-$6,936,302	$0	$0	-$14,109,266	-$124,616	-$157,812	$0	$0	-$282,428
Renewable Generation Connection Capital Deferral Account[9]	1531	$0				$0	$0				$0
Renewable Generation Connection OM&A Deferral Account[9]	1532	$0				$0	$0				$0
Renewable Generation Connection Funding Adder Deferral Account	1533	$0				$0	$0				$0
Smart Grid Capital Deferral Account	1534	$0				$0	$0				$0
Smart Grid OM&A Deferral Account	1535	$0				$0	$0				$0
Smart Grid Funding Adder Deferral Account	1536	$0				$0	$0				$0
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital[5]	1555	$0				$0	$0				$0
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries[5]	1555	$0				$0	$0				$0
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs[5]	1555	$3,073,694	$477,063			$3,550,757	$0				$0
Smart Meter OM&A Variance[5]	1556	$0				$0	$0				$0
Meter Cost Deferral Account (MIST Meters)[11]	1557										
IFRS-CGAAP Transition PP&E Amounts Balance + Return Component[6]	1575					$0					
Accounting Changes Under CGAAP Balance + Return Component[6]	1576										

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Account Descriptions	Account Number	2012 Opening Principal Amounts as of Jan-1-12	Transactions[1] Debit / (Credit) during 2012	OEB-Approved Disposition during 2012	Principal Adjustments[2] during 2012	Closing Principal Balance as of Dec-31-12	Opening Interest Amounts as of Jan-1-12	Interest Jan-1 to Dec-31-12	OEB-Approved Disposition during 2012	Interest Adjustments[2] during 2012	Closing Interest Amounts as of Dec-31-12
Group 1 Accounts											
LV Variance Account	1550	$0				$0	$0				$0
Smart Metering Entity Charge Variance Account	1551										
RSVA - Wholesale Market Service Charge[10]	1580	-$8,261,909	-$4,541,452	-$3,937,692		-$8,865,669	-$115,645	-$118,296	-$531,390		$297,449
Variance WMS – Sub-account CBR Class A[10]	1580										
Variance WMS – Sub-account CBR Class B[10]	1580										
RSVA - Retail Transmission Network Charge	1584	$774,015	$818,948	$329,189		$1,263,774	$11,977	$18,431	$215,308		-$184,900
RSVA - Retail Transmission Connection Charge	1586	-$279,774	$563,625	-$530,629		$814,480	-$17,419	$5,796	-$87,076		$75,453
RSVA - Power (excluding Global Adjustment)	1588	-$3,896,805	-$1,067,614	-$947,934		-$4,016,485	-$193,776	-$67,780	-$836,349		$574,793
RSVA - Global Adjustment	1589	-$2,612,754	$3,829,924	-$1,275,974		$2,493,144	$27,680	$53,534	-$40,192		$121,406
Disposition and Recovery/Refund of Regulatory Balances (2009)[8]	1595	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2010)[8]	1595	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2011)[8]	1595	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2012)[8]	1595	$0	-$4,602,893			-$4,602,893	$0	-$1,020,475			-$1,020,475
Disposition and Recovery/Refund of Regulatory Balances (2013)[8]	1595	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2014)[8]	1595	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2015)[8]	1595	$0				$0	$0				$0
Not to be disposed of unless rate rider has expired and balance has been audited											
Group 1 Sub-Total (including Account 1589 - Global Adjustment)		-$14,277,227	-$4,999,461	-$6,363,040	$0	-$12,913,648	-$287,183	-$1,128,790	-$1,279,699	$0	-$136,274
Group 1 Sub-Total (excluding Account 1589 - Global Adjustment)		-$11,664,473	-$8,829,385	-$5,087,066	$0	-$15,406,792	-$314,863	-$1,182,324	-$1,239,507	$0	-$257,680
RSVA - Global Adjustment	**1589**	-$2,612,754	$3,829,924	-$1,275,974	$0	$2,493,144	$27,680	$53,534	-$40,192	$0	$121,406
Group 2 Accounts											
Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	1508	$349,024	$12,940			$361,964	$6,650	$5,217			$11,867
Other Regulatory Assets - Sub-Account - Incremental Capital Charges	1508	$0				$0	$0				$0
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act[3]	1508	$0				$0	$0				$0
Other Regulatory Assets - Sub-Account - Other [4]	1508	$0				$0	$0				$0
Retail Cost Variance Account - Retail	1518	-$82,253	-$8,898			-$91,151	-$1,531	-$1,234			-$2,765
Misc. Deferred Debits	1525	$0				$0	$0				$0
Retail Cost Variance Account - STR	1548	$86,736	$31,007			$117,743	$1,488	$1,486			$2,974
Board-Approved CDM Variance Account	1567	$0				$0	$0				$0
Extra-Ordinary Event Costs	1572	$0				$0	$0				$0
Deferred Rate Impact Amounts	1574	$0				$0	$0				$0
RSVA - One-time	1582	$0				$0	$0				$0
Other Deferred Credits	2425	$0				$0	$0				$0
Group 2 Sub-Total		$353,507	$35,049	$0	$0	$388,556	$6,607	$5,469	$0	$0	$12,076
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)	1592	$0				$0	$0				$0
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592	-$185,546	-$153,586			-$339,132	-$1,852	-$3,766			-$5,618
Total of Group 1 and Group 2 Accounts (including 1592)		-$14,109,266	-$5,117,998	-$6,363,040	$0	-$12,864,225	-$282,428	-$1,127,087	-$1,279,699	$0	-$129,816
LRAM Variance Account[12]	**1568**	$0	$102,235			$102,235	$0	$684			$684

Account Descriptions	Account Number	2012 Opening Principal Amounts as of Jan-1-12	Transactions[1] Debit/ (Credit) during 2012	OEB-Approved Disposition during 2012	Principal Adjustments[2] during 2012	Closing Principal Balance as of Dec-31-12	Opening Interest Amounts as of Jan-1-12	Interest Jan-1 to Dec-31-12	OEB-Approved Disposition during 2012	Interest Adjustments[2] during 2012	Closing Interest Amounts as of Dec-31-12
Total including Account 1568		-$14,109,266	-$5,015,763	-$6,363,040	$0	-$12,761,990	-$282,428	-$1,126,402	-$1,279,699	$0	-$129,132
Renewable Generation Connection Capital Deferral Account[9]	1531	$0				$0	$0				$0
Renewable Generation Connection OM&A Deferral Account[9]	1532	$0				$0	$0				$0
Renewable Generation Connection Funding Adder Deferral Account	1533	$0				$0	$0				$0
Smart Grid Capital Deferral Account	1534	$0				$0	$0				$0
Smart Grid OM&A Deferral Account	1535	$0				$0	$0				$0
Smart Grid Funding Adder Deferral Account	1536	$0				$0	$0				$0
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital[5]	1555	$0				$0	$0				$0
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries[5]	1555	$0				$0	$0				$0
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs[5]	1555	$3,550,757	-$396,675			$3,154,082	$0				$0
Smart Meter OM&A Variance[5]	1556	$0				$0	$0				$0
Meter Cost Deferral Account (MIST Meters)[11]	1557										
IFRS-CGAAP Transition PP&E Amounts Balance + Return Component[6]	1575	$0				$0					
Accounting Changes Under CGAAP Balance + Return Component[6]	1576					$0					

Account Descriptions	Account Number	Opening Principal Amounts as of Jan-1-13	Transactions[1] Debit / (Credit) during 2013	OEB-Approved Disposition during 2013	Principal Adjustments[2] during 2013	Closing Principal Balance as of Dec-31-13	Opening Interest Amounts as of Jan-1-13	Interest Jan-1 to Dec-31-13	OEB-Approved Disposition during 2013	Interest Adjustments[2] during 2013	Closing Interest Amounts as of Dec-31-13
		2013									
Group 1 Accounts											
LV Variance Account	1550	$0				$0	$0				$0
Smart Metering Entity Charge Variance Account	1551	$0	$101,107			$101,107	$0	$1,078			$1,078
RSVA - Wholesale Market Service Charge[10]	1580	-$8,865,669	-$2,267,271	-$4,324,217		-$6,808,723	$297,449	-$105,841	$331,281		-$139,673
Variance WMS – Sub-account CBR Class A[10]	1580										
Variance WMS – Sub-account CBR Class B[10]	1580										
RSVA - Retail Transmission Network Charge	1584	$1,263,774	$603,898	$444,826		$1,422,846	-$184,900	$17,332	-$194,642		$27,074
RSVA - Retail Transmission Connection Charge	1586	$814,480	$428,156	$250,855		$991,782	$75,453	$9,582	$74,557		$10,478
RSVA - Power (excluding Global Adjustment)	1588	-$4,016,485	-$449,761	-$4,016,485		-$449,761	$574,793	-$6,938	$555,382		$12,473
RSVA - Global Adjustment	1589	$2,493,144	$1,977,886	$2,493,144	-$135,064	$1,842,822	$121,406	$38,666	$133,455	-$2,004	$24,613
Disposition and Recovery/Refund of Regulatory Balances (2009)[8]	1595	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2010)[8]	1595	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2011)[8]	1595	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2012)[8]	1595	-$4,602,893	$3,791,360			-$811,533	-$1,020,475	-$42,195			-$1,062,671
Disposition and Recovery/Refund of Regulatory Balances (2013)[8]	1595	$0	-$2,516,194			-$2,516,194	$0	$561,427			$561,427
Disposition and Recovery/Refund of Regulatory Balances (2014)[8]	1595	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2015)[8]	1595	$0				$0	$0				$0
Not to be disposed of unless rate rider has expired and balance has been audited											
Group 1 Sub-Total (including Account 1589 - Global Adjustment)		-$12,913,648	$1,669,181	-$5,151,877	-$135,064	-$6,227,655	-$136,274	$473,111	$900,033	-$2,004	-$565,200
Group 1 Sub-Total (excluding Account 1589 - Global Adjustment)		-$15,406,792	-$308,706	-$7,645,021	$0	-$8,070,477	-$257,680	$434,445	$766,578	$0	-$589,813
RSVA - Global Adjustment	**1589**	$2,493,144	$1,977,886	$2,493,144	-$135,064	$1,842,822	$121,406	$38,666	$133,455	-$2,004	$24,613
Group 2 Accounts											
Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	1508	$361,964		$349,024		$12,940	$11,867	$1,877	$13,466		$278
Other Regulatory Assets - Sub-Account - Incremental Capital Charges	1508	$0				$0	$0				$0
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act[3]	1508	$0				$0	$0				$0
Other Regulatory Assets - Sub-Account - Other[4]	1508	$0				$0	$0				$0
Retail Cost Variance Account - Retail	1518	-$91,151	-$9,104	-$82,253		-$18,002	-$2,765	-$605	-$3,138		-$232
Misc. Deferred Debits	1525	$0				$0	$0				$0
Retail Cost Variance Account - STR	1548	$117,743	$32,235	$86,736		$63,242	$2,974	$1,088	$3,182		$880
Board-Approved CDM Variance Account	1567	$0				$0	$0				$0
Extra-Ordinary Event Costs	1572	$0				$0	$0				$0
Deferred Rate Impact Amounts	1574	$0				$0	$0				$0
RSVA - One-time	1582	$0				$0	$0				$0
Other Deferred Credits	2425	$0				$0	$0				$0
Group 2 Sub-Total		$388,556	$23,131	$353,507	$0	$58,180	$12,076	$2,361	$13,511	$0	$926
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)	1592	$0				$0	$0				$0
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592	-$339,132		-$185,546		-$153,586	-$5,618	-$3,154	-$5,476		-$3,296
Total of Group 1 and Group 2 Accounts (including 1592)		-$12,864,225	$1,692,312	-$4,983,916	-$135,064	-$6,323,061	-$129,816	$472,317	$908,068	-$2,004	-$567,570
LRAM Variance Account[12]	**1568**	$102,235	-$56,859			$45,376	$684	$1,120			$1,804

Account Descriptions	Account Number	2013 Opening Principal Amounts as of Jan-1-13	Transactions[1] Debit/ (Credit) during 2013	OEB-Approved Disposition during 2013	Principal Adjustments[2] during 2013	Closing Principal Balance as of Dec-31-13	Opening Interest Amounts as of Jan-1-13	Interest Jan-1 to Dec-31-13	OEB-Approved Disposition during 2013	Interest Adjustments[2] during 2013	Closing Interest Amounts as of Dec-31-13
Total including Account 1568		-$12,761,990	$1,635,453	-$4,983,916	-$135,064	-$6,277,685	-$129,132	$473,437	$908,068	-$2,004	-$565,766
Renewable Generation Connection Capital Deferral Account[9]	1531	$0				$0	$0				$0
Renewable Generation Connection OM&A Deferral Account[9]	1532	$0				$0	$0				$0
Renewable Generation Connection Funding Adder Deferral Account	1533	$0				$0	$0				$0
Smart Grid Capital Deferral Account	1534	$0				$0	$0				$0
Smart Grid OM&A Deferral Account	1535	$0				$0	$0				$0
Smart Grid Funding Adder Deferral Account	1536	$0				$0	$0				$0
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital[5]	1555	$0				$0	$0				$0
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries[5]	1555	$0				$0	$0				$0
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs[5]	1555	$3,154,082	-$1,812,923			$1,341,159	$0	$24,324			$24,324
Smart Meter OM&A Variance[5]	1556	$0				$0	$0				$0
Meter Cost Deferral Account (MIST Meters)[11]	1557										
IFRS-CGAAP Transition PP&E Amounts Balance + Return Component[6]	1575	$0				$0					
Accounting Changes Under CGAAP Balance + Return Component[6]	1576	$0				$0					

Account Descriptions	Account Number	2014 Opening Principal Amounts as of Jan-1-14	Transactions[1] Debit / (Credit) during 2014	OEB-Approved Disposition during 2014	Principal Adjustments[2] during 2014	Closing Principal Balance as of Dec-31-14	Opening Interest Amounts as of Jan-1-14	Interest Jan-1 to Dec-31-14	OEB-Approved Disposition during 2014	Interest Adjustments[2] during 2014	Closing Interest Amounts as of Dec-31-14
Group 1 Accounts											
LV Variance Account	1550	$0				$0	$0				$0
Smart Metering Entity Charge Variance Account	1551	$101,107	-$20,817			$80,290	$1,078	$1,362			$2,440
RSVA - Wholesale Market Service Charge[10]	1580	-$6,808,723	-$502,001			-$7,310,725	-$139,673	-$81,083			-$220,756
Variance WMS – Sub-account CBR Class A[10]	1580										
Variance WMS – Sub-account CBR Class B[10]	1580										
RSVA - Retail Transmission Network Charge	1584	$1,422,846	$883,604			$2,306,449	$27,074	$27,754			$54,828
RSVA - Retail Transmission Connection Charge	1586	$991,782	$500,625			$1,492,407	$10,478	$20,599			$31,077
RSVA - Power (excluding Global Adjustment)	1588	-$449,761	-$17,320			-$467,081	$12,473	-$2,885			$9,589
RSVA - Global Adjustment	1589	$1,842,822	$7,614,471		-$314,016	$9,143,276	$24,613	$27,864		-$3,853	$48,623
Disposition and Recovery/Refund of Regulatory Balances (2009)[8]	1595	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2010)[8]	1595	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2011)[8]	1595	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2012)[8]	1595	-$811,533	$811,533			-$0	-$1,062,671	$764,329			-$298,342
Disposition and Recovery/Refund of Regulatory Balances (2013)[8]	1595	-$2,516,194	$1,938,970			-$577,224	$561,427	-$15,420			$546,007
Disposition and Recovery/Refund of Regulatory Balances (2014)[8]	1595	$0	$43,856			$43,856	$0	$3,472			$3,472
Disposition and Recovery/Refund of Regulatory Balances (2015)[8]	1595	$0				$0	$0				$0
Not to be disposed of unless rate rider has expired and balance has been audited											
Group 1 Sub-Total (including Account 1589 - Global Adjustment)		-$6,227,655	$11,252,920	$0	-$314,016	$4,711,249	-$565,200	$745,991	$0	-$3,853	$176,938
Group 1 Sub-Total (excluding Account 1589 - Global Adjustment)		-$8,070,477	$3,638,450	$0	$0	-$4,432,027	-$589,813	$718,127	$0	$0	$128,314
RSVA - Global Adjustment	**1589**	$1,842,822	$7,614,471	$0	-$314,016	$9,143,276	$24,613	$27,864	$0	-$3,853	$48,623
Group 2 Accounts											
Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	1508	$12,940	$5,000			$17,940	$278	$190			$468
Other Regulatory Assets - Sub-Account - Incremental Capital Charges	1508	$0				$0	$0				$0
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act[3]	1508	$0				$0	$0				$0
Other Regulatory Assets - Sub-Account - Other [4]	1508	$0				$0	$0				$0
Retail Cost Variance Account - Retail	1518	-$18,002	$4,247			-$13,754	-$232	-$248			-$479
Misc. Deferred Debits	1525	$0				$0	$0				$0
Retail Cost Variance Account - STR	1548	$63,242	$34,601			$97,843	$880	$1,163			$2,043
Board-Approved CDM Variance Account	1567	$0				$0	$0				$0
Extra-Ordinary Event Costs	1572	$0				$0	$0				$0
Deferred Rate Impact Amounts	1574	$0				$0	$0				$0
RSVA - One-time	1582	$0				$0	$0				$0
Other Deferred Credits	2425	$0				$0	$0				$0
Group 2 Sub-Total		$58,180	$43,849	$0	$0	$102,029	$926	$1,106	$0	$0	$2,031
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)	1592	$0				$0	$0				$0
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592	-$153,586				-$153,586	-$3,296	-$2,258			-$5,553
Total of Group 1 and Group 2 Accounts (including 1592)		-$6,323,061	$11,296,769	$0	-$314,016	$4,659,692	-$567,570	$744,839	$0	-$3,853	$173,416
LRAM Variance Account[12]	**1568**	$45,376	$85,234	$102,235		$28,375	$1,804	$233	$2,681		-$645

		2014									
Account Descriptions	Account Number	Opening Principal Amounts as of Jan-1-14	Transactions[1] Debit / (Credit) during 2014	OEB-Approved Disposition during 2014	Principal Adjustments[2] during 2014	Closing Principal Balance as of Dec-31-14	Opening Interest Amounts as of Jan-1-14	Interest Jan-1 to Dec-31-14	OEB-Approved Disposition during 2014	Interest Adjustments[2] during 2014	Closing Interest Amounts as of Dec-31-14
Total including Account 1568		-$6,277,685	$11,382,003	$102,235	-$314,016	$4,688,066	-$565,766	$745,072	$2,681	-$3,853	$172,771
Renewable Generation Connection Capital Deferral Account[9]	1531	$0				$0	$0				$0
Renewable Generation Connection OM&A Deferral Account[9]	1532	$0				$0	$0				$0
Renewable Generation Connection Funding Adder Deferral Account	1533	$0				$0	$0				$0
Smart Grid Capital Deferral Account	1534	$0				$0	$0				$0
Smart Grid OM&A Deferral Account	1535	$0				$0	$0				$0
Smart Grid Funding Adder Deferral Account	1536	$0				$0	$0				$0
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital[5]	1555	$0				$0	$0				$0
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries[5]	1555	$0				$0	$0				$0
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs[5]	1555	$1,341,159	-$1,337,724			$3,435	$24,324	$2,683			$27,006
Smart Meter OM&A Variance[5]	1556	$0				$0	$0				$0
Meter Cost Deferral Account (MIST Meters)[11]	1557	$0				$0	$0				$0
IFRS-CGAAP Transition PP&E Amounts Balance + Return Component[6]	1575	$0				$0					
Accounting Changes Under CGAAP Balance + Return Component[6]	1576	$0				$0					

Account Descriptions	Account Number	2015 Opening Principal Amounts as of Jan-1-15	Transactions[1] Debit / (Credit) during 2015	OEB-Approved Disposition during 2015	Principal Adjustments[2] during 2015	Closing Principal Balance as of Dec-31-15	Opening Interest Amounts as of Jan-1-15	Interest Jan-1 to Dec-31-15	OEB-Approved Disposition during 2015	Interest Adjustments[2] during 2015	Closing Interest Amounts as of Dec-31-15
Group 1 Accounts											
LV Variance Account	1550	$0				$0	$0				$0
Smart Metering Entity Charge Variance Account	1551	$80,290	-$24,551			$55,739	$2,440	$835			$3,275
RSVA - Wholesale Market Service Charge[10]	1580	-$7,310,725	-$7,099,446			-$14,410,171	-$220,756	-$113,363			-$334,119
Variance WMS – Sub-account CBR Class A[10]	1580	$0	$46,059			$46,059	$0	$146			$146
Variance WMS – Sub-account CBR Class B[10]	1580	$0	$816,554			$816,554	$0	$2,724			$2,724
RSVA - Retail Transmission Network Charge	1584	$2,306,449	-$227,019			$2,079,430	$54,828	$25,282			$80,110
RSVA - Retail Transmission Connection Charge	1586	$1,492,407	-$560,336			$932,071	$31,077	$15,965			$47,042
RSVA - Power (excluding Global Adjustment)	1588	-$467,081	-$372,517			-$839,599	$9,589	$75			$9,664
RSVA - Global Adjustment	1589	$9,143,276	-$462,328		-$304,093	$8,376,856	$48,623	$81,611		-$7,084	$123,150
Disposition and Recovery/Refund of Regulatory Balances (2009)[8]	1595	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2010)[8]	1595	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2011)[8]	1595	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2012)[8]	1595	-$0				-$0	-$298,342				-$298,342
Disposition and Recovery/Refund of Regulatory Balances (2013)[8]	1595	-$577,224				-$577,224	$546,007	-$6,876			$539,131
Disposition and Recovery/Refund of Regulatory Balances (2014)[8]	1595	$43,856	-$42,688			$1,168	$3,472	$161			$3,633
Disposition and Recovery/Refund of Regulatory Balances (2015)[8]	1595	$0				$0	$0				$0
Not to be disposed of unless rate rider has expired and balance has been audited											
Group 1 Sub-Total (including Account 1589 - Global Adjustment)		$4,711,249	-$7,926,272	$0	-$304,093	-$3,519,115	$176,938	$6,560	$0	-$7,084	$176,414
Group 1 Sub-Total (excluding Account 1589 - Global Adjustment)		-$4,432,027	-$7,463,944	$0	$0	-$11,895,972	$128,314	-$75,051	$0	$0	$53,264
RSVA - Global Adjustment	**1589**	$9,143,276	-$462,328	$0	-$304,093	$8,376,856	$48,623	$81,611	$0	-$7,084	$123,150
Group 2 Accounts											
Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	1508	$17,940	$7,600			$25,540	$468	$277			$744
Other Regulatory Assets - Sub-Account - Incremental Capital Charges	1508	$0				$0	$0				$0
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act[3]	1508	$0				$0	$0				$0
Other Regulatory Assets - Sub-Account - Other [4]	1508	$0				$0	$0				$0
Retail Cost Variance Account - Retail	1518	-$13,754	$99,977			$86,223	-$479	$2,150			$1,671
Misc. Deferred Debits	1525	$0				$0	$0				$0
Retail Cost Variance Account - STR	1548	$97,843	-$97,933			-$90	$2,043	-$2,112			-$70
Board-Approved CDM Variance Account	1567	$0				$0	$0				$0
Extra-Ordinary Event Costs	1572	$0				$0	$0				$0
Deferred Rate Impact Amounts	1574	$0				$0	$0				$0
RSVA - One-time	1582	$0				$0	$0				$0
Other Deferred Credits	2425	$0				$0	$0				$0
Group 2 Sub-Total		$102,029	$9,644	$0	$0	$111,672	$2,031	$315	$0	$0	$2,346
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)	1592	$0				$0	$0				$0
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592	-$153,586				-$153,586	-$5,553	-$1,830			-$7,383
Total of Group 1 and Group 2 Accounts (including 1592)		$4,659,692	-$7,916,628	$0	-$304,093	-$3,561,029	$173,416	$5,045	$0	-$7,084	$171,377
LRAM Variance Account[12]	**1568**	$28,375	$412,778			$441,153	-$645	$2,451			$1,807

Account Descriptions	Account Number	2015 Opening Principal Amounts as of Jan-1-15	Transactions[1] Debit/ (Credit) during 2015	OEB-Approved Disposition during 2015	Principal Adjustments[2] during 2015	Closing Principal Balance as of Dec-31-15	Opening Interest Amounts as of Jan-1-15	Interest Jan-1 to Dec-31-15	OEB-Approved Disposition during 2015	Interest Adjustments[2] during 2015	Closing Interest Amounts as of Dec-31-15
Total including Account 1568		$4,688,066	-$7,503,850	$0	-$304,093	-$3,119,876	$172,771	$7,497	$0	-$7,084	$173,184
Renewable Generation Connection Capital Deferral Account[9]	1531	$0				$0	$0				$0
Renewable Generation Connection OM&A Deferral Account[9]	1532	$0				$0	$0				$0
Renewable Generation Connection Funding Adder Deferral Account	1533	$0				$0	$0				$0
Smart Grid Capital Deferral Account	1534	$0				$0	$0				$0
Smart Grid OM&A Deferral Account	1535	$0				$0	$0				$0
Smart Grid Funding Adder Deferral Account	1536	$0				$0	$0				$0
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital[5]	1555	$0				$0	$0				$0
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries[5]	1555	$0				$0	$0				$0
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs[5]	1555	$3,435				$3,435	$27,006	$41			$27,047
Smart Meter OM&A Variance[5]	1556	$0				$0	$0				$0
Meter Cost Deferral Account (MIST Meters)[11]	1557	$0				$0	$0				$0
IFRS-CGAAP Transition PP&E Amounts Balance + Return Component[6]	1575	$0				$0					
Accounting Changes Under CGAAP Balance + Return Component[6]	1576	$0				$0					

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Account Descriptions	Account Number	2016 Principal Disposition during 2016 - instructed by OEB	Interest Disposition during 2016 - instructed by OEB	Closing Principal Balances as of Dec 31-15 Adjusted for Dispositions during 2016	Closing Interest Balances as of Dec 31-15 Adjusted for Dispositions during 2016	Projected Interest on Dec-31-15 Balances: Projected Interest from Jan 1, 2016 to December 31, 2016 on Dec 31 -15 balance adjusted for disposition during 2016 [7]	Projected Interest from January 1, 2017 to April 30, 2017 on Dec 31 -15 balance adjusted for disposition during 2016 [7]	Total Interest	Total Claim	2.1.7 RRR As of Dec 31-15	Variance RRR vs. 2015 Balance *(Principal + Interest)*
Group 1 Accounts											
LV Variance Account	1550			$0	$0			$0	$0.00		$0
Smart Metering Entity Charge Variance Account	1551	$80,290	$3,688	-$24,551	-$413	$22	-$89	-$480	-$25,031.11	$59,014	-$0
RSVA - Wholesale Market Service Charge[10]	1580	-$7,310,725	-$334,430	-$7,099,446	$311	-$104,680	-$25,675	-$130,044	-$7,229,490.04	-$14,744,290	-$0
Variance WMS – Sub-account CBR Class A[10]	1580			$46,059	$146	$507	$167	$819	☐ Check to $0.00	$46,205	$0
Variance WMS – Sub-account CBR Class B[10]	1580			$816,554	$2,724	$8,982	$2,953	$14,659	☑ Check to $831,213.82	$819,279	$0
RSVA - Retail Transmission Network Charge	1584	$2,306,449	$90,691	-$227,019	-$10,581	$5,890	-$821	-$5,511	-$232,530.53	$2,159,540	$0
RSVA - Retail Transmission Connection Charge	1586	$1,492,407	$54,283	-$560,336	-$7,240	-$736	-$2,026	-$10,003	-$570,339.37	$979,113	-$0
RSVA - Power (excluding Global Adjustment)	1588	-$467,081	$2,326	-$372,517	$7,338	-$5,796	-$1,347	$194	-$372,322.88	-$829,934	$1
RSVA - Global Adjustment	1589	$9,143,276	$190,792	-$766,420	-$67,641	$24,820	-$2,772	-$45,593	-$812,013.39	$9,266,120	$766,114
Disposition and Recovery/Refund of Regulatory Balances (2009)[8]	1595			$0	$0			$0	☐ Check to $0.00		$0
Disposition and Recovery/Refund of Regulatory Balances (2010)[8]	1595			$0	$0			$0	☐ Check to $0.00		$0
Disposition and Recovery/Refund of Regulatory Balances (2011)[8]	1595			$0	$0			$0	☐ Check to $0.00		$0
Disposition and Recovery/Refund of Regulatory Balances (2012)[8]	1595	$0	-$298,342	-$0	-$0	$0	$0	-$0	☐ Check to $0.00	-$298,342	$0
Disposition and Recovery/Refund of Regulatory Balances (2013)[8]	1595	-$577,224	$537,032	$0	$2,099	-$2,099	$0	$0	☐ Check to $0.00	-$38,093	-$0
Disposition and Recovery/Refund of Regulatory Balances (2014)[8]	1595			$1,168	$3,633	$13	$4	$3,650	☑ Check to $4,818.07	$4,801	$0
Disposition and Recovery/Refund of Regulatory Balances (2015)[8]	1595			$0	$0			$0	☐ Check to $0.00		$0
Not to be disposed of unless rate rider has expired and balance has been audited											
Group 1 Sub-Total (including Account 1589 - Global Adjustment)		$4,667,393	$246,039	-$8,186,508	-$69,625	-$73,078	-$29,606	-$172,309	-$8,405,695.43	-$2,576,587	$766,115
Group 1 Sub-Total (excluding Account 1589 - Global Adjustment)		-$4,475,883	$55,247	-$7,420,088	-$1,983	-$97,898	-$26,834	-$126,716	-$7,593,682.04	-$11,842,707	$1
RSVA - Global Adjustment	**1589**	$9,143,276	$190,792	-$766,420	-$67,641	$24,820	-$2,772	-$45,593	-$812,013.39	$9,266,120	$766,114
Group 2 Accounts											
Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	1508			$25,540	$744	$281	$92	$1,118	$26,657.52	$26,284	$0
Other Regulatory Assets - Sub-Account - Incremental Capital Charges	1508			$0	$0			$0	$0.00		$0
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act[3]	1508			$0	$0			$0	$0.00		$0
Other Regulatory Assets - Sub-Account - Other [4]	1508			$0	$0			$0	☐ Check to $0.00		$0
Retail Cost Variance Account - Retail	1518			$86,223	$1,671	$948	$312	$2,932	$89,154.37	$87,894	-$0
Misc. Deferred Debits	1525			$0	$0			$0	☐ Check to $0.00		$0
Retail Cost Variance Account - STR	1548			-$90	-$70	-$1	-$0	-$71	-$161.14	-$160	-$0
Board-Approved CDM Variance Account	1567			$0	$0			$0	$0.00		$0
Extra-Ordinary Event Costs	1572			$0	$0			$0	$0.00		$0
Deferred Rate Impact Amounts	1574			$0	$0			$0	$0.00		$0
RSVA - One-time	1582			$0	$0			$0	$0.00		$0
Other Deferred Credits	2425			$0	$0			$0	☐ Check to $0.00		$0
Group 2 Sub-Total		$0	$0	$111,672	$2,346	$1,228	$404	$3,978	$115,650.75	$114,018	-$0
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)	1592			$0	$0			$0	$0.00		$0
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592			-$153,586	-$7,383	-$1,689	-$555	-$9,628	-$163,213.89	-$160,969	-$0
Total of Group 1 and Group 2 Accounts (including 1592)		$4,667,393	$246,039	-$8,228,422	-$74,662	-$73,539	-$29,758	-$177,958	-$8,453,258.57	-$2,623,538	$766,114
LRAM Variance Account[12]	**1568**			$441,153	$1,807	$4,853	$1,618	$8,277	$449,429.67	$1,215,463	$772,504

Account Descriptions	Account Number	2016 Principal Disposition during 2016 - instructed by OEB	Interest Disposition during 2016 - instructed by OEB	Closing Principal Balances as of Dec 31-15 Adjusted for Dispositions during 2016	Closing Interest Balances as of Dec 31-15 Adjusted for Dispositions during 2016	Projected Interest on Dec-31-15 Balances: Projected Interest from Jan 1, 2016 to December 31, 2016 on Dec 31 -15 balance adjusted for disposition during 2016 [7]	Projected Interest from January 1, 2017 to April 30, 2017 on Dec 31 -15 balance adjusted for disposition during 2016 [7]	Total Interest	Total Claim	2.1.7 RRR As of Dec 31-15	Variance RRR vs. 2015 Balance (Principal + Interest)
									☐ Check to		
Total including Account 1568		$4,667,393	$246,039	-$7,787,269	-$72,855	-$68,686	-$28,140	-$169,682	-$8,003,828.90	-$1,408,075	$1,538,618
Renewable Generation Connection Capital Deferral Account[9]	1531			$0	$0			$0	$0.00		$0
Renewable Generation Connection OM&A Deferral Account[9]	1532			$0	$0			$0	$0.00		$0
Renewable Generation Connection Funding Adder Deferral Account	1533			$0	$0			$0	$0.00		$0
Smart Grid Capital Deferral Account	1534			$0	$0			$0	$0.00		$0
Smart Grid OM&A Deferral Account	1535			$0	$0			$0	$0.00		$0
Smart Grid Funding Adder Deferral Account	1536			$0	$0			$0	$0.00		$0
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital[5]	1555			$0	$0			$0	$0.00		$0
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries[5]	1555			$0	$0			$0	$0.00		$0
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter (	1555			$3,435	$27,047	$38	$12	$27,098	$30,532.34	$30,438	-$44
Smart Meter OM&A Variance[5]	1556			$0	$0			$0	$0.00		$0
Meter Cost Deferral Account (MIST Meters)[11]	1557			$0	$0			$0	$0.00		$0
IFRS-CGAAP Transition PP&E Amounts Balance + Return Component[6]	1575			$0					☐ Check to $0.00		$0
Accounting Changes Under CGAAP Balance + Return Component[6]	1576			$0					☐ Check to $0.00		$0

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Ontario Energy Board

2017 Deferral/Variance Account Workform

Accounts that produced a variance on the continuity schedule are listed below.
Please provide a detailed explanation for each variance below.

	Account Descriptions	Account Number	Variance RRR vs. 2015 Balance *(Principal + Interest)*	Explanation
2	Smart Metering Entity Charge Variance Account	1551	$ (0.01)	Rounding
3	RSVA - Wholesale Market Service Charge10	1580	$ (0.01)	Rounding
4	RSVA - Retail Transmission Network Charge	1584	$ 0.01	Rounding
5	RSVA - Retail Transmission Connection Charge	1586	$ (0.00)	Rounding
6	RSVA - Power (excluding Global Adjustment)	1588	$ 0.66	Rounding
7	RSVA - Global Adjustment	1589	$ 766,113.87	Class A and New Class A GA Balances at December 31, 2015 are not included in EDDVAR model
11	Disposition and Recovery/Refund of Regulatory Balances (2012)8	1595	$ 0.01	Rounding
12	Disposition and Recovery/Refund of Regulatory Balances (2013)8	1595	$ (0.00)	Rounding
15	Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	1508	$ 0.00	Rounding
19	Retail Cost Variance Account - Retail	1518	$ (0.19)	Rounding
21	Retail Cost Variance Account - STR	1548	$ (0.24)	Rounding
28	PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs	1592	$ (0.15)	Rounding
29	LRAM Variance Account12	1568	$ 772,503.85	Corrections to LRAMVA Balances - New guidelines
1 38	Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs5	1555	$ (44.08)	Interest Adjustment

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2017 Deferral/Variance Account Workform

If a Class B customer switched into Class A this check box: ☑

Identify the total consumption for former Cl becoming Class A customers (i.e. Jan 1. to

In the green shaded cells, enter the data related to the **proposed** load forecast. Do not enter data for the MicroFit class.

			A		B			C		D=A-C	
Rate Class (Enter Rate Classes in cells below as they appear on your current tariff of rates and charges)	**Units**	**# of Customers**	**Total Metered kWh**	**Total Metered kW**	**Metered kWh for Non-RPP Customers**	**Estimated Metered kW for Non-RPP Customers**	**Distribution Revenue**	**Metered kWh for Wholesale Market Participants (WMP)**	**Metered kW for Wholesale Market Participants (WMP)**	**Total Metered kWh less WMP consumption *(if applicable)***	**Total Metered kW less WMP consumption *(if applicable)***
RESIDENTIAL SERVICE CLASSIFICATION	kWh	142,509	1,068,671,798		62,268,991	-				1,068,671,798	-
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFIC	kWh	12,749	371,911,863		62,326,448	-				371,911,863	-
GENERAL SERVICE 50 TO 4,999 KW SERVICE CLASSIFICATI	kW	1,561	1,469,047,930	3,778,018	1,350,181,966	3,472,325		-	31,946	1,469,047,930	3,746,072
GENERAL SERVICE 1,000 TO 4,999 KW (CO-GENERATION) S	kW	4	10,203,354	65,844	10,203,354	65,844				10,203,354	65,844
STANDBY POWER SERVICE CLASSIFICATION	kW	3	23,988,201	154,800	23,988,201	154,800				23,988,201	154,800
LARGE USE SERVICE CLASSIFICATION	kW	1	82,923,505	159,628	82,923,505	159,628				82,923,505	159,628
STREET LIGHTING SERVICE CLASSIFICATION	kW	35,912	19,502,488	54,607	19,502,488	54,607				19,502,488	54,607
SENTINEL LIGHTING SERVICE CLASSIFICATION	kW	599	706,221	1,907	18,632	50				706,221	1,907
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	kWh	1,537	5,464,035		102,372	-				5,464,035	-
						-				-	-
						-				-	-
						-				-	-
						-				-	-
						-				-	-
						-				-	-
						-				-	-
						-				-	-
						-				-	-
						-				-	-
						-				-	-
Total		**194,875**	**3,052,419,395**	**4,214,804**	**1,611,515,957**	**3,907,254**	**$ -**	**-**	**31,946**	**3,052,419,395**	**4,182,858**

*For new Class A customers (who became Class A in 2015), add their consumption only related to July to December period.

[1] Residual Account balance to be allocated to rate classes in proportion to the recovery share as established when rate riders were implemented.

[2] The proportion of customers for the Residential and GS<50 Classes will be used to allocate Account 1551.

1 [3] Input the allocation as determined in the LRAMVA model. The associated rate riders will be calculated in the EDDVAR model.

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		E				F =B-C-E	
Rate Class **(Enter Rate Classes in cells below as they appear on your current tariff of rates and charges)**	**Units**	**Metered kWh for any Class A Customers in 2015 (partial or full year) (if applicable)***	**Metered kW for any Class A Customers in 2015 (partial or full year) (if applicable)**	**Metered kWh Consumption for New Class A customer(s) in the period prior to becoming Class A (i.e. Jan. 1 - June 30, 2015)**	**Metered kW Consumption for New Class A customer(s) in the period prior to becoming Class A (i.e. Jan. 1 - June 30, 2015)**	**Metered Consumption kWh for Current Class B Customers (Non-RPP consumption LESS WMP, Class A and new Class A's former Class B consumption, if applicable)**	**Total Metered kW for Non-RPP Customers less WMP and Class A Consumption**
RESIDENTIAL SERVICE CLASSIFICATION	kWh					62,268,991	-
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFIC	kWh					62,326,448	-
GENERAL SERVICE 50 TO 4,999 KW SERVICE CLASSIFICATI	kW	48,842,761	184,298	33,089,331	73,642	1,268,249,874	3,182,439
GENERAL SERVICE 1,000 TO 4,999 KW (CO-GENERATION) S	kW	6,258,933	31,212	2,767,899	23,639	1,176,521	10,993
STANDBY POWER SERVICE CLASSIFICATION	kW	16,632,696	77,400	7,355,506	77,400	0	-
LARGE USE SERVICE CLASSIFICATION	kW	82,923,505	159,628			-	-
STREET LIGHTING SERVICE CLASSIFICATION	kW					19,502,488	54,607
SENTINEL LIGHTING SERVICE CLASSIFICATION	kW					18,632	50
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	kWh					102,372	-
						-	-
						-	-
						-	-
						-	-
						-	-
						-	-
						-	-
						-	-
						-	-
						-	-
						-	-
1 **Total**		**154,657,895**	**452,538**			**1,413,645,327**	**3,248,089**

Rate Class (Enter Rate Classes in cells below as they appear on your current tariff of rates and charges)	Units	1595 Recovery Share Proportion (2009) [1]	1595 Recovery Share Proportion (2010) [1]	1595 Recovery Share Proportion (2011) [1]	1595 Recovery Share Proportion (2012) [1]	1595 Recovery Share Proportion (2013) [1]	1595 Recovery Share Proportion (2014) [1]	1595 Recovery Share Proportion (2015) [1]	1568 LRAM Variance Account Class Allocation[3] ($ amounts)	Number of Customers for Residential and GS<50 classes[2]
RESIDENTIAL SERVICE CLASSIFICATION	kWh						42%		91,371	142,509
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFIC	kWh						12%		284,131	12,749
GENERAL SERVICE 50 TO 4,999 KW SERVICE CLASSIFICATI	kW						46%		169,775	
GENERAL SERVICE 1,000 TO 4,999 KW (CO-GENERATION) S	kW								(10,554)	
STANDBY POWER SERVICE CLASSIFICATION	kW								(24,813)	
LARGE USE SERVICE CLASSIFICATION	kW								(33,978)	
STREET LIGHTING SERVICE CLASSIFICATION	kW								(22,143)	
SENTINEL LIGHTING SERVICE CLASSIFICATION	kW								(950)	
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	kWh								(3,410)	
Total		**0%**	**0%**	**0%**	**0%**	**0%**		**0%**	**$ 449,430**	

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		Amounts from Sheet 2	Allocator	RESIDENTIAL SERVICE CLASSIFICATION	GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION	GENERAL SERVICE 50 TO 4,999 KW SERVICE CLASSIFICATION	GENERAL SERVICE 1,000 TO 4,999 KW (CO-GENERATION) SERVICE CLASSIFICATION
LV Variance Account	1550	0	kWh	0	0	0	0
Smart Metering Entity Charge Variance Account	1551	(25,031)	# of Customers	(22,976)	(2,055)	0	0
RSVA - Wholesale Market Service Charge	1580	(7,229,490)	kWh	(2,531,091)	(880,853)	(3,479,360)	(24,166)
RSVA - Retail Transmission Network Charge	1584	(232,531)	kWh	(81,410)	(28,332)	(111,911)	(777)
RSVA - Retail Transmission Connection Charge	1586	(570,339)	kWh	(199,680)	(69,491)	(274,489)	(1,906)
RSVA - Power (excluding Global Adjustment)	1588	(372,323)	kWh	(130,353)	(45,364)	(179,189)	(1,245)
RSVA - Global Adjustment	1589	(812,013)	Non-RPP kWh	(35,768)	(35,801)	(728,497)	(676)
Disposition and Recovery/Refund of Regulatory Balances (2009)	1595	0	%	0	0	0	0
Disposition and Recovery/Refund of Regulatory Balances (2010)	1595	0	%	0	0	0	0
Disposition and Recovery/Refund of Regulatory Balances (2011)	1595	0	kWh	0	0	0	0
Disposition and Recovery/Refund of Regulatory Balances (2012)	1595	0	%	0	0	0	0
Disposition and Recovery/Refund of Regulatory Balances (2013)	1595	0	kWh	0	0	0	0
Disposition and Recovery/Refund of Regulatory Balances (2014)	1595	4,818	%	2,024	578	2,216	0
Disposition and Recovery/Refund of Regulatory Balances (2015)	1595	0	%	0	0	0	0
Total of Group 1 Accounts (excluding 1589)		**(8,424,896)**		**(2,963,486)**	**(1,025,518)**	**(4,042,733)**	**(28,094)**
Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	1508	26,658	kWh	9,333	3,248	12,830	89
Other Regulatory Assets - Sub-Account - Incremental Capital Charges	1508	0	kWh	0	0	0	0
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act	1508	0	kWh	0	0	0	0
Other Regulatory Assets - Sub-Account - Other	1508	0	kWh	0	0	0	0
Retail Cost Variance Account - Retail	1518	89,154	# of Customers	65,197	5,833	714	2
Misc. Deferred Debits	1525	0	kWh	0	0	0	0
Retail Cost Variance Account - STR	1548	(161)	# of Customers	(118)	(11)	(1)	(0)
Board-Approved CDM Variance Account	1567	0	kWh	0	0	0	0
Extra-Ordinary Event Costs	1572	0	kWh	0	0	0	0
Deferred Rate Impact Amounts	1574	0	kWh	0	0	0	0
RSVA - One-time	1582	0	kWh	0	0	0	0
Other Deferred Credits	2425	0	kWh	0	0	0	0
Total of Group 2 Accounts		**115,651**		**74,412**	**9,070**	**13,542**	**91**
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account)	1592	0	kWh	0	0	0	0
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592	(163,214)	kWh	(57,142)	(19,886)	(78,550)	(546)
Total of Account 1592		**(163,214)**		**(57,142)**	**(19,886)**	**(78,550)**	**(546)**
LRAM Variance Account **(Enter dollar amount for each class)**	1568	**449,430**		91,371	284,131	169,775	(10,554)
(Account 1568 - total amount allocated to classes)		449,430					
Variance		**(0)**					
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs	1555	**30,532**	Residual Balances	27,777	2,755		
Total of Group 1 Accounts (1550, 1551, 1584, 1586 and 1595)		**(823,083)**		**(302,042)**	**(99,300)**	**(384,184)**	**(2,684)**
Total of Account 1580 and 1588 (not allocated to WMPs)		**(7,601,813)**		**(2,661,444)**	**(926,218)**	**(3,658,550)**	**(25,411)**
Balance of Account 1589 Allocated to Non-WMPs		**(812,013)**		**(35,768)**	**(35,801)**	**(728,497)**	**(676)**
Group 2 Accounts (including 1592, 1532)		**(17,031)**		**45,047**	**(8,061)**	**(65,008)**	**(455)**
IFRS-CGAAP Transition PP&E Amounts Balance + Return Component	1575	0	kWh	0	0	0	0
Accounting Changes Under CGAAP Balance + Return Component	1576	0	kWh	0	0	0	0
Total Balance Allocated to each class for Accounts 1575 and 1576		**0**		**0**	**0**	**0**	**0**

Account 1589 reference calculation by customer and consumption	
Account 1589 / Number of Customers	($4.17)
1589/total kwh	($0.0003)

		Amounts from Sheet 2	Allocator	STANDBY POWER SERVICE CLASSIFICATION	LARGE USE SERVICE CLASSIFICATION	STREET LIGHTING SERVICE CLASSIFICATION	SENTINEL LIGHTING SERVICE CLASSIFICATION	UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION
LV Variance Account	1550	0	kWh	0	0	0	0	0
Smart Metering Entity Charge Variance Account	1551	(25,031)	# of Customers	0	0	0	0	0
RSVA - Wholesale Market Service Charge	1580	(7,229,490)	kWh	(56,815)	(196,400)	(46,191)	(1,673)	(12,941)
RSVA - Retail Transmission Network Charge	1584	(232,531)	kWh	(1,827)	(6,317)	(1,486)	(54)	(416)
RSVA - Retail Transmission Connection Charge	1586	(570,339)	kWh	(4,482)	(15,494)	(3,644)	(132)	(1,021)
RSVA - Power (excluding Global Adjustment)	1588	(372,323)	kWh	(2,926)	(10,115)	(2,379)	(86)	(666)
RSVA - Global Adjustment	1589	(812,013)	Non-RPP kWh	(0)	0	(11,202)	(11)	(59)
Disposition and Recovery/Refund of Regulatory Balances (2009)	1595	0	%	0	0	0	0	0
Disposition and Recovery/Refund of Regulatory Balances (2010)	1595	0	%	0	0	0	0	0
Disposition and Recovery/Refund of Regulatory Balances (2011)	1595	0	kWh	0	0	0	0	0
Disposition and Recovery/Refund of Regulatory Balances (2012)	1595	0	%	0	0	0	0	0
Disposition and Recovery/Refund of Regulatory Balances (2013)	1595	0	kWh	0	0	0	0	0
Disposition and Recovery/Refund of Regulatory Balances (2014)	1595	4,818	%	0	0	0	0	0
Disposition and Recovery/Refund of Regulatory Balances (2015)	1595	0	%	0	0	0	0	0
Total of Group 1 Accounts (excluding 1589)		**(8,424,896)**		**(66,050)**	**(228,326)**	**(53,699)**	**(1,945)**	**(15,045)**
Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	1508	26,658	kWh	209	724	170	6	48
Other Regulatory Assets - Sub-Account - Incremental Capital Charges	1508	0	kWh	0	0	0	0	0
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act	1508	0	kWh	0	0	0	0	0
Other Regulatory Assets - Sub-Account - Other	1508	0	kWh	0	0	0	0	0
Retail Cost Variance Account - Retail	1518	89,154	# of Customers	1	0	16,430	274	703
Misc. Deferred Debits	1525	0	kWh	0	0	0	0	0
Retail Cost Variance Account - STR	1548	(161)	# of Customers	(0)	(0)	(30)	(0)	(1)
Board-Approved CDM Variance Account	1567	0	kWh	0	0	0	0	0
Extra-Ordinary Event Costs	1572	0	kWh	0	0	0	0	0
Deferred Rate Impact Amounts	1574	0	kWh	0	0	0	0	0
RSVA - One-time	1582	0	kWh	0	0	0	0	0
Other Deferred Credits	2425	0	kWh	0	0	0	0	0
Total of Group 2 Accounts		**115,651**		**211**	**725**	**16,570**	**280**	**750**
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account)	1592	0	kWh	0	0	0	0	0
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592	(163,214)	kWh	(1,283)	(4,434)	(1,043)	(38)	(292)
Total of Account 1592		**(163,214)**		**(1,283)**	**(4,434)**	**(1,043)**	**(38)**	**(292)**
LRAM Variance Account **(Enter dollar amount for each class)**	1568	**449,430**		(24,813)	(33,978)	(22,143)	(950)	(3,410)
(Account 1568 - total amount allocated to classes)		449,430						
Variance		**(0)**						
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs	1555	**30,532**	Residual Balances					
Total of Group 1 Accounts (1550, 1551, 1584, 1586 and 1595)		**(823,083)**		**(6,310)**	**(21,811)**	**(5,130)**	**(186)**	**(1,437)**
Total of Account 1580 and 1588 (not allocated to WMPs)		**(7,601,813)**		**(59,741)**	**(206,515)**	**(48,569)**	**(1,759)**	**(13,608)**
Balance of Account 1589 Allocated to Non-WMPs		**(812,013)**		**(0)**	**0**	**(11,202)**	**(11)**	**(59)**
Group 2 Accounts (including 1592, 1532)		**(17,031)**		**(1,072)**	**(3,709)**	**15,527**	**242**	**457**
IFRS-CGAAP Transition PP&E Amounts Balance + Return Component	1575	0	kWh	0	0	0	0	0
Accounting Changes Under CGAAP Balance + Return Component	1576	0	kWh	0	0	0	0	0
Total Balance Allocated to each class for Accounts 1575 and 1576		**0**		**0**	**0**	**0**	**0**	**0**

1

Please indicate the Rate Rider Recovery Period (in years) | **1**

Rate Rider Calculation for Deferral / Variance Accounts Balances (excluding Globa

1550, 1551, 1584, 1586, 1595

Rate Class (Enter Rate Classes in cells below)	Units	kW / kWh / # of Customers	Allocated Balance (excluding 1589)	Rate Rider for Deferral/Variance Accounts
RESIDENTIAL SERVICE CLASSIFICATION	kWh	1,068,671,798	-$ 302,042	- **0.0003**
GENERAL SERVICE LESS THAN 50 KW	kWh	371,911,863	-$ 99,300	- **0.0003**
GENERAL SERVICE 50 TO 4,999 KW SE	kW	3,778,018	-$ 384,184	- **0.1017**
GENERAL SERVICE 1,000 TO 4,999 KW (	kW	65,844	-$ 2,684	- **0.0408**
STANDBY POWER SERVICE CLASSIFIC	kW	154,800	-$ 6,310	- **0.0408**
LARGE USE SERVICE CLASSIFICATION	kW	159,628	-$ 21,811	- **0.1366**
STREET LIGHTING SERVICE CLASSIFICA	kW	54,607	-$ 5,130	- **0.0939**
SENTINEL LIGHTING SERVICE CLASSIFI	kW	1,907	-$ 186	- **0.0974**
UNMETERED SCATTERED LOAD SERVI	kWh	5,464,035	-$ 1,437	- **0.0003**
		-	$ -	-
		-	$ -	-
		-	$ -	-
		-	$ -	-
		-	$ -	-
		-	$ -	-
		-	$ -	-
		-	$ -	-
		-	$ -	-
		-	$ -	-
		-	$ -	-
Total			**-$ 823,083**	

Rate Rider Calculation for Deferral / Variance Accounts Balances (excluding Global Adj.) - NON-WM

1580 and 1588

Rate Class (Enter Rate Classes in cells below)	Units	kW / kWh / # of Customers	Allocated Balance (excluding 1589)	Rate Rider for Deferral/Variance Accounts
RESIDENTIAL SERVICE CLASSIFICATION	kWh	1,068,671,798	-$ 2,661,444	- **0.0025**
GENERAL SERVICE LESS THAN 50 KW	kWh	371,911,863	-$ 926,218	- **0.0025**
GENERAL SERVICE 50 TO 4,999 KW SE	kW	3,746,072	-$ 3,658,550	- **0.9766**
GENERAL SERVICE 1,000 TO 4,999 KW (	kW	65,844	-$ 25,411	- **0.3859**
STANDBY POWER SERVICE CLASSIFIC	kW	154,800	-$ 59,741	- **0.3859**
LARGE USE SERVICE CLASSIFICATION	kW	159,628	-$ 206,515	- **1.2937**
STREET LIGHTING SERVICE CLASSIFICA	kW	54,607	-$ 48,569	- **0.8894**
SENTINEL LIGHTING SERVICE CLASSIFI	kW	1,907	-$ 1,759	- **0.9223**
UNMETERED SCATTERED LOAD SERVI	kWh	5,464,035	-$ 13,608	- **0.0025**
		-	$ -	-
		-	$ -	-
		-	$ -	-
		-	$ -	-
		-	$ -	-
		-	$ -	-
		-	$ -	-
		-	$ -	-
		-	$ -	-
		-	$ -	-
		-	$ -	-
Total			**-$ 7,601,813**	

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Rate Rider Calculation for RSVA - Power - Global Adjustment

Balance of Account 1589 Allocated to Non-WMPs

Rate Class (Enter Rate Classes in cells below)	Units	kWh	Balance of RSVA - Power - Global Adjustment	Rate Rider for RSVA - Power - Global Adjustment
RESIDENTIAL SERVICE CLASSIFICATION	kWh	62,268,991	-$ 35,768	- **0.0006**
GENERAL SERVICE LESS THAN 50 KW	kWh	62,326,448	-$ 35,801	- **0.0006**
GENERAL SERVICE 50 TO 4,999 KW SE	kWh	1,268,249,874	-$ 728,497	- **0.0006**
GENERAL SERVICE 1,000 TO 4,999 KW (	kWh	1,176,521	-$ 676	- **0.0006**
STANDBY POWER SERVICE CLASSIFICA	kWh	0	-$ 0	- **0.0006**
LARGE USE SERVICE CLASSIFICATION	kWh	-	$ -	**-**
STREET LIGHTING SERVICE CLASSIFICA	kWh	19,502,488	-$ 11,202	- **0.0006**
SENTINEL LIGHTING SERVICE CLASSIFI	kWh	18,632	-$ 11	- **0.0006**
UNMETERED SCATTERED LOAD SERVIC	kWh	102,372	-$ 59	- **0.0006**
	kWh	-	$ -	**-**
		-	$ -	**-**
		-	$ -	**-**
		-	$ -	**-**
		-	$ -	**-**
		-	$ -	**-**
		-	$ -	**-**
		-	$ -	**-**
		-	$ -	**-**
		-	$ -	**-**
		-	$ -	**-**
Total			**-$ 812,013**	

Rate Rider Calculation for Group 2 Accounts

Rate Class (Enter Rate Classes in cells below)	Units	# of Customers	Balance of Group 2 Accounts	Rate Rider for RSVA - Power - Global Adjustment
RESIDENTIAL SERVICE CLASSIFICATION	# of Customers	142,509	$ 45,047	**$ 0.03**
GENERAL SERVICE LESS THAN 50 KW	# of Customers	12,749	-$ 8,061	**-$ 0.0527**
GENERAL SERVICE 50 TO 4,999 KW SE	# of Customers	1,561	-$ 65,008	**-$ 3.4704**
GENERAL SERVICE 1,000 TO 4,999 KW (	# of Customers	4	-$ 455	**-$ 9.4717**
STANDBY POWER SERVICE CLASSIFICA	# of Customers	3	-$ 1,072	**-$ 29.7720**
LARGE USE SERVICE CLASSIFICATION	# of Customers	1	-$ 3,709	**-$ 309.1083**
STREET LIGHTING SERVICE CLASSIFICA	# of Customers	35,912	$ 15,527	**$ 0.0360**
SENTINEL LIGHTING SERVICE CLASSIFI	# of Customers	599	$ 242	**$ 0.0337**
UNMETERED SCATTERED LOAD SERVIC	# of Customers	1,537	$ 457	**$ 0.0248**
		-	$ -	**$ -**
		-	$ -	**$ -**
		-	$ -	**$ -**
		-	$ -	**$ -**
		-	$ -	**$ -**
		-	$ -	**$ -**
		-	$ -	**$ -**
		-	$ -	**$ -**
		-	$ -	**$ -**
		-	$ -	**$ -**
		-	$ -	**$ -**
Total			**-$ 17,031**	

Rate Rider Calculation for Accounts 1575 and 1576

Please indicate the Rate Rider Recovery Period (in years) 1

Rate Class (Enter Rate Classes in cells below)	Units	# of Customers	Balance of Accounts 1575 and 1576	Rate Rider for Accounts 1575 and 1576
RESIDENTIAL SERVICE CLASSIFICATION	# of Customers	142,509	$ -	-
GENERAL SERVICE LESS THAN 50 KW	# of Customers	12,749	$ -	-
GENERAL SERVICE 50 TO 4,999 KW SE	# of Customers	1,561	$ -	-
GENERAL SERVICE 1,000 TO 4,999 KW	# of Customers	4	$ -	-
STANDBY POWER SERVICE CLASSIFIC	# of Customers	3	$ -	-
LARGE USE SERVICE CLASSIFICATION	# of Customers	1	$ -	-
STREET LIGHTING SERVICE CLASSIFICA	# of Customers	35,912	$ -	-
SENTINEL LIGHTING SERVICE CLASSIFI	# of Customers	599	$ -	-
UNMETERED SCATTERED LOAD SERVI	kWh	5,464,035	$ -	-
		-	$ -	-
		-	$ -	-
		-	$ -	-
		-	$ -	-
		-	$ -	-
		-	$ -	-
		-	$ -	-
		-	$ -	-
		-	$ -	-
		-	$ -	-
		-	$ -	-
Total			**$ -**	

Rate Rider Calculation for Accounts 1568

Please indicate the Rate Rider Recovery Period (in years) 1

Rate Class (Enter Rate Classes in cells below)	Units	kW / kWh / # of Customers	Balance of Account 1568	Rate Rider for Account 1568
RESIDENTIAL SERVICE CLASSIFICATION	kWh	1,068,671,798	$ 91,371	**0.0001**
GENERAL SERVICE LESS THAN 50 KW	kWh	371,911,863	$ 284,131	**0.0008**
GENERAL SERVICE 50 TO 4,999 KW SE	**kW**	3,778,018	$ 169,775	**0.0449**
GENERAL SERVICE 1,000 TO 4,999 KW	**kW**	65,844	-$ 10,554	**- 0.1603**
STANDBY POWER SERVICE CLASSIFIC	**kW**	154,800	-$ 24,813	**- 0.1603**
LARGE USE SERVICE CLASSIFICATION	**kW**	159,628	-$ 33,978	**- 0.2129**
STREET LIGHTING SERVICE CLASSIFICA	**kW**	54,607	-$ 22,143	**- 0.4055**
SENTINEL LIGHTING SERVICE CLASSIFI	**kW**	1,907	-$ 950	**- 0.4982**
UNMETERED SCATTERED LOAD SERVI	kWh	5,464,035	-$ 3,410	**- 0.0006**
		-	$ -	-
		-	$ -	-
		-	$ -	-
		-	$ -	-
		-	$ -	-
		-	$ -	-
		-	$ -	-
		-	$ -	-
		-	$ -	-
		-	$ -	-
		-	$ -	-
Total			**$ 449,430**	

File Number:	EB-2016-0091
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APPENDIX 2 OF 5
APPENDIX 9B ONE-TIME INCREMENTAL IFRS TRANSITION COSTS

File Number:	EB-2016-0091
Exhibit:	9
Tab:	
Schedule:	
Page:	
Date:	8/26/2016

Appendix 2-YA
One-Time Incremental IFRS Transition Costs

The following table should be completed based on the information requested below. An explanation should be provided for any blank entries. The entries should include one-time incremental IFRS transition costs that are currently included in Account 1508, Other Regulatory Assets, sub-account Deferred IFRS Transition Costs Account, or Account 1508, Other Regulatory Assets, sub-account IFRS Transition Costs Variance Account.

Nature of One-Time Incremental IFRS Transition Costs [1]	Audited Actual Costs Incurred 2012	Audited Actual Costs Incurred 2013	Audited Actual Costs Incurred 2014	Audited Actual Costs Incurred 2015	Audited Carrying Charges To December 31, 2015	Forecasted Costs 2016	Forecasted Costs 2017 [3]	Carrying Charges January 1, 2016 to December 31,2016/April 30, 2017 (As	Total Costs and Carrying Charges	Reasons why the costs recorded meet the criteria of one-time IFRS administrative incremental costs
Professional accounting consulting fees - conversion from Canadian GAAP to IFRS	$ 33,090				$ 1,659			$ 484	$ 35,233	Consulting fees paid to KMPG Accounting Firm
Professional legal fees									$ -	
Salaries, wages and benefits of staff added to support the transition to									$ -	
Associated staff training and development costs									$ -	
Costs related to system upgrades, or replacements or changes where IFRS was the major reason for conversion									$ -	
Pension actuarial to IFRS	$ 4,850		$ 5,000	$ 7,600	$ 379			$ 255	$ 18,084	Consulting fees paid to Actuarial Firm
									$ -	
									$ -	
									$ -	
Amounts, if any, included in previous Board approved rates (amounts should be negative) [2] - Amount approved as per decision and order, effective September 1, 2009 - EB-2008-0235	-$ 25,000				-$ 1,309			-$ 365	-$ 26,674	
									$ -	
Insert description of additional item(s) and new rows if needed.									$ -	
Total	$ 12,940	$ -	$ 5,000	$ 7,600	$ 729		$ -	$ 373	$ 26,643	

Note:

1 The Deferred IFRS Transition Costs Account and the IFRS Transition Costs Variance Account are exclusively for necessary, incremental transition costs and shall not include ongoing IFRS compliance costs or impacts arising from adopting accounting policy changes that reflect changes in the timing of the recognition of income. The incremental costs in these accounts shall not include costs related to system upgrades, or replacements or changes where IFRS was not the major reason for conversion. In addition, incremental IFRS costs shall not include

2 If there were any amounts approved in previous Board approved rates, please state the EB-2012-0146

3 Any forecasted One-time costs past 2015 should be fully explained in the application, since distributors were required to adopt IFRS or an alternative accounting standard by January 1, 2015.

London Hydro

File Number:	EB-2016-0091
Exhibit:	9
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Date Filed:	August 26, 2016

APPENDIX 3 OF 5
APPENDIX 9C CLIMATE CHANGE PROJECTS ED CAPITAL AND OM&A DISPOSAL GENERATOR REVENUE REQUIREMENT AND RATE RIDER CALCULATION

Distributor Information

Applicant Name	**London Hydro Inc.**
OEB Licence Number	**ED-2002-0557**
OEB File Number	**EB-2016-0091**
Capital Structure Transition - Rated Utility Size	**Med-Large**
Last Re-basing Year - COS	**2013**

ED Capital OM&A Rate Generator   release 1.0

Name of LDC: **London Hydro Inc.**

OEB Application: **EB-2016-0091**

This Application

First Year of Deferral	2010

Claimed Years

2010	Yes
2011	Yes
2012	Yes
2013	Yes
2014	Yes
2015	Yes
2016	Yes
2017	No
2018	No
2019	No

Year of Disposition	2017

Distributor Assumptions and Data

Distributor Assumptions and Data	2010	2011	2012	2013	2014	2015	2016
Rate Base							
Deemed Short Term Debt %	4%	4%	4%	4%	4%	4%	4%
Deemed Debt	56%	56%	56%	56%	56%	56%	56%
Deemed Equity	40%	40%	40%	40%	40%	40%	40%
Deemed Short Term Debt Rate%	1.33%	2.07%	2.07%	2.07%	2.07%	1.65%	1.65%
Weighted Debt Rate	7.62%	4.58%	4.58%	4.58%	4.58%	2.71%	2.71%
Proposed ROE	8.01%	8.98%	8.98%	8.98%	8.98%	9.19%	9.19%
Weighted Average Cost of Capital	7.52%	6.24%	6.24%	6.24%	6.24%	5.26%	5.26%
Working Capital Allowance %	15.00%	15.00%	15.00%	11.42%	11.42%	11.42%	11.42%
Corporate Income Tax Rate	31.00%	28.25%	25.63%	25.45%	25.45%	25.45%	26.50%
Ontario Capital Tax	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
Depreciation Rates	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**
Software CIS(years)	5	5	5	5	5	5	5
Software Green Button (years)	5	5	5	5	5	5	5
Var Compensator (years)	5	5	5	5	5	5	5
Asset 4 (years)							
Asset 5 (years)							
CCA Rates	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**
CCA Class	12	12	12	12	12	12	12
Software CIS	100%	100%	100%	100%	100%	100%	100%
CCA Class	12	12	12	12	12	12	12
Software Green Button	100%	100%	100%	100%	100%	100%	100%
CCA Class	47	47	47	47	47	47	47
Var Compensator	8%	8%	8%	8%	8%	8%	8%

	Approved Deferral and Variance Accounts Rate (per the Bankers' Acceptances-3 months Plus 0.25 Spread)
Q2 2006	4.14
Q3 2006	4.59
Q4 2006	4.59
Q1 2007	4.59
Q2 2007	4.59
Q3 2007	4.59
Q4 2007	5.14
Q1 2008	5.14
Q2 2008	4.08
Q3 2008	3.35
Q4 2008	3.35
Q1 2009	2.45
Q2 2009	1.00
Q3 2009	0.55
Q4 2009	0.55
Q1 2010	0.55
Q2 2010	0.55
Q3 2010	0.89
Q4 2010	1.20
Q1 2011	1.47
Q2 2011	1.47
Q3 2011	1.47
Q4 2011	1.47
Q1 2012	1.47
Q2 2012	1.47
Q3 2012	1.47
Q4 2012	1.47
Q1 2013	1.47
Q2 2013	1.47
Q3 2013	1.47
Q4 2013	1.47

1

	Approved Deferral and Variance Accounts Rate (per the Bankers' Acceptances-3 months Plus 0.25 Spread)
Q1 2014	1.47
Q2 2014	1.47
Q3 2014	1.47
Q4 2014	1.47
Q1 2015	1.47
Q2 2015	1.10
Q3 2015	1.10
Q4 2015	1.10
Q1 2016	1.10
Q2 2016	1.10
Q3 2016	1.10
Q4 2016	1.10
Q1 2017	1.10
Q2 2017	1.10
Q3 2017	1.10
Q4 2017	1.10
Q1 2018	1.10
Q2 2018	1.10
Q3 2018	1.10
Q4 2018	1.10
Q1 2019	1.10
Q2 2019	1.10
Q3 2019	1.10
Q4 2019	1.10
Q1 2020	1.10
Q2 2020	1.10
Q3 2020	1.10
Q4 2020	1.10
Q1 2021	1.10
Q2 2021	1.10
Q3 2021	1.10
Q4 2021	1.10

Capital Cost Data

1.1 Software CIS

	Asset Type	2010	2011	2012	2013	2014	2015	2016	**Total**
1.1.1 Software CIS	**Software CIS**	9,953		19,900	500			-	**$ 30,353**
Total Software CIS		**$ 9,953**	**$ -**	**$ 19,900**	**$ 500**	**$ -**	**$ -**	**$ -**	**$ 30,353**

1.2 Software Green Button

	Asset Type	2010	2011	2012	2013	2014	2015	2016	Total
1.2.1 Software Green Button	**Software Green Button**	-	-	-	6,793	307,751	56,207	-	**$ 370,751**
Total Software Green Button		**$ -**	**$ -**	**$ -**	**$ 6,793**	**$ 307,751**	**$ 56,207**	**$ -**	**$ 370,751**

1.3 Var Compensator

	Asset Type	2010	2011	2012	2013	2014	2015	2016	Total
1.3.1 Var Compensator	**Var Compensator**		-	-	-	-	18,918	3,621	**$ 22,540**
Total Var Compensator		**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 18,918**	**$ 3,621**	**$ 22,540**

1 **Total Capital Costs**	**$ 9,953**	**$ -**	**$ 19,900**	**$ 7,293**	**$ 307,751**	**$ 75,125**	**$ 3,621**	**$ 423,643**

Operational Expense Data

2.1 Green Button

	2010	2011	2012	2013	2014	2015	2016	Total
2.1.1 Green Button				17,669	61,234	42,251	-	**$ 121,154**
Total Green Button	**$ -**	**$ -**	**$ -**	**$ 17,669**	**$ 61,234**	**$ 42,251**	**$ -**	**$ 121,154**

2.2 NSERC Project

	2010	2011	2012	2013	2014	2015	2016	
2.2.1 NSERC Project		-	-	-	6,682	19,662	-	**$ 26,345**
Total NSERC Project	**$ -**	**$ -**	**$ -**	**$ -**	**$ 6,682**	**$ 19,662**	**$ -**	**$ 26,345**

Research Projects with UWO and OCE

	2010	2011	2012	2013	2014	2015	2016	
2.3.1 Watts Lab		93,617	(74,991)	2,506	-	-	-	**$ 21,133**
2.3.2 Renewable Generation Studies	26,815	18,009	8,000	-	66,000	-	-	**$ 118,824**
Total Research Projects with UWO and OCE	**$ 26,815**	**$ 111,627**	**-$ 66,991**	**$ 2,506**	**$ 66,000**	**$ -**	**$ -**	**$ 139,957**

2.4 London Energy Mapping

	2010	2011	2012	2013	2014	2015	2016	
2.4.1 London Energy Mapping		10,000	-	-	-	-	-	**$ 10,000**
Total London Energy Mapping	**$ -**	**$ 10,000**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 10,000**

2.5 EMAP

	2010	2011	2012	2013	2014	2015	2016	
2.5.1 EMAP		-	-	37,892	84,238	10,159	-	**$ 132,289**
Total 2.5 EMAP	**$ -**	**$ -**	**$ -**	**$ 37,892**	**$ 84,238**	**$ 10,159**	**$ -**	**$ 132,289**

	2010	2011	2012	2013	2014	2015	2016	Total
1 **Total O M & A Costs**	**$ 26,815**	**$ 121,627**	**-$ 66,991**	**$ 58,067**	**$ 218,154**	**$ 72,072**	**$ -**	**$ 429,744**

Summary

Capital Data:	2010	2011	2012	2013	2014	2015	2016	Total
Software CIS	9,953	-	19,900	500	-	-	-	30,353
Software Green Button	-	-	-	6,793	307,751	56,207	-	370,751
Var Compensator	-	-	-	-	-	18,918	3,621	22,540
Asset 4	-	-	-	-	-	-	-	-
Asset 5	-	-	-	-	-	-	-	-
Total Capital Costs	9,953	-	19,900	7,293	307,751	75,125	3,621	423,643
								-

Operating Expense Data:	2010	2011	2012	2013	2014	2015	2016	Total
2.1 Green Button	-	-	-	17,669	61,234	42,251	-	121,154
2.2 NSERC Project	-	-	-	-	6,682	19,662	-	26,345
2.3 Research Projects with UWO and OCE	26,815	111,627	(66,991)	2,506	66,000	-	-	139,957
24 London Energy Mapping	-	10,000	-	-	-	-	-	10,000
2.5 EMAP	-	-	-	37,892	84,238	10,159	-	132,289
1 **Total O M & A Costs**	26,815	121,627	(66,991)	58,067	218,154	72,072	-	429,744

Average Net Fixed Assets & UCC

Average Net Fixed Assets

Net Fixed Assets - Software CIS

	2010	2011	2012	2013	2014	2015	2016
Opening Capital Investment	$ -	$ 9,953	$ 9,953	$ 29,853	$ 30,353	$ 30,353	$ 30,353
Capital Investment	$ 9,953	$ -	$ 19,900	$ 500	$ -	$ -	$ -
Closing Capital Investment	$ 9,953	$ 9,953	$ 29,853	$ 30,353	$ 30,353	$ 30,353	$ 30,353
Opening Accumulated Amortization	$ -	$ 995	$ 2,986	$ 6,966	$ 12,987	$ 19,057	$ 25,128
Amortization (5 Years Straight Line)	$ 995	$ 1,991	$ 3,981	$ 6,021	$ 6,071	$ 6,071	$ 5,225
Closing Accumulated Amortization	$ 995	$ 2,986	$ 6,966	$ 12,987	$ 19,057	$ 25,128	$ 30,353
Opening Net Fixed Assets	$ -	$ 8,957	$ 6,967	$ 22,886	$ 17,366	$ 11,295	$ 5,225
Closing Net Fixed Assets	$ 8,957	$ 6,967	$ 22,886	$ 17,366	$ 11,295	$ 5,225	$ -
Average Net Fixed Assets	$ 4,479	$ 7,962	$ 14,927	$ 20,126	$ 14,331	$ 8,260	$ 2,612

Net Fixed Assets - Software Green Button

	2010	2011	2012	2013	2014	2015	2016
Opening Capital Investment	$ -	$ -	$ -	$ -	$ 6,793	$ 314,544	$ 370,751
Capital Investment	$ -	$ -	$ -	$ 6,793	$ 307,751	$ 56,207	$ -
Closing Capital Investment	$ -	$ -	$ -	$ 6,793	$ 314,544	$ 370,751	$ 370,751
Opening Accumulated Amortization	$ -	$ -	$ -	$ -	$ 679	$ 32,813	$ 101,343
Amortization (5 Years Straight Line)	$ -	$ -	$ -	$ 679	$ 32,134	$ 68,530	$ 74,150
Closing Accumulated Amortization	$ -	$ -	$ -	$ 679	$ 32,813	$ 101,343	$ 175,493
Opening Net Fixed Assets	$ -	$ -	$ -	$ -	$ 6,114	$ 281,731	$ 269,409
Closing Net Fixed Assets	$ -	$ -	$ -	$ 6,114	$ 281,731	$ 269,409	$ 195,258
Average Net Fixed Assets	$ -	$ -	$ -	$ 3,057	$ 143,922	$ 275,570	$ 232,333

Net Fixed Assets - Var Compensator

	2010	2011	2012	2013	2014	2015	2016
Opening Capital Investment	$ -	$ -	$ -	$ -	$ -	$ -	$ 18,918
Capital Investment	$ -	$ -	$ -	$ -	$ -	$ 18,918	$ 3,621
Closing Capital Investment	$ -	$ -	$ -	$ -	$ -	$ 18,918	$ 22,540
Opening Accumulated Amortization	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,892
Amortization (5 Years Straight Line)	$ -	$ -	$ -	$ -	$ -	$ 1,892	$ 4,146
Closing Accumulated Amortization	$ -	$ -	$ -	$ -	$ -	$ 1,892	$ 6,038
Opening Net Fixed Assets	$ -	$ -	$ -	$ -	$ -	$ -	$ 17,026
Closing Net Fixed Assets	$ -	$ -	$ -	$ -	$ -	$ 17,026	$ 16,502
Average Net Fixed Assets	$ -	$ -	$ -	$ -	$ -	$ 8,513	$ 16,764

For PILs Calculation

UCC - Software CIS

	2010	2011	2012	2013	2014	2015	2016
Opening UCC	$ -	$ 4,976	$ -	$ 9,950	$ 250	$ -	$ -
Capital Additions	$ 9,953	$ -	$ 19,900	$ 500	$ -	$ -	$ -
UCC Before Half Year Rule	$ 9,953	$ 4,976	$ 19,900	$ 10,450	$ 250	$ -	$ -
Half Year Rule (1/2 Additions - Disposals)	$ 4,976	$ -	$ 9,950	$ 250	$ -	$ -	$ -
Reduced UCC	$ 4,976	$ 4,976	$ 9,950	$ 10,200	$ 250	$ -	$ -
CCA Rate Class	12	12	12	12	12	12	12
CCA Rate	100%	100%	100%	100%	100%	100%	100%
CCA	$ 4,976	$ 4,976	$ 9,950	$ 10,200	$ 250	$ -	$ -
Closing UCC	$ 4,976	$ -	$ 9,950	$ 250	$ -	$ -	$ -

UCC - Software Green Button

	2010	2011	2012	2013	2014	2015	2016
Opening UCC	$ -	$ -	$ -	$ -	$ 3,397	$ 153,876	$ 28,103
Capital Additions Computer Hardware	$ -	$ -	$ -	$ 6,793	$ 307,751	$ 56,207	$ -
Capital Additions Computer Software							
UCC Before Half Year Rule	$ -	$ -	$ -	$ 6,793	$ 311,148	$ 210,083	$ 28,103
Half Year Rule (1/2 Additions - Disposals)	$ -	$ -	$ -	$ 3,397	$ 153,876	$ 28,103	$ -
Reduced UCC	$ -	$ -	$ -	$ 3,397	$ 157,272	$ 181,979	$ 28,103
CCA Rate Class	12	12	12	12	12	12	12
CCA Rate	100%	100%	100%	100%	100%	100%	100%
CCA	$ -	$ -	$ -	$ 3,397	$ 157,272	$ 181,979	$ 28,103
Closing UCC	$ -	$ -	$ -	$ 3,397	$ 153,876	$ 28,103	$ -

UCC - Var Compensator

	2010	2011	2012	2013	2014	2015	2016
Opening UCC	$ -	$ -	$ -	$ -	$ -	$ -	$ 18,161
Capital Additions Tools & Equipment	$ -	$ -	$ -	$ -	$ -	$ 18,918	$ 3,621
Capital Additions Other Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -
UCC Before Half Year Rule	$ -	$ -	$ -	$ -	$ -	$ 18,918	$ 21,783
Half Year Rule (1/2 Additions - Disposals)	$ -	$ -	$ -	$ -	$ -	$ 9,459	$ 1,811
Reduced UCC	$ -	$ -	$ -	$ -	$ -	$ 9,459	$ 19,972
CCA Rate Class	47	47	47	47	47	47	47
CCA Rate	8%	8%	8%	8%	8%	8%	8%
CCA	$ -	$ -	$ -	$ -	$ -	$ 757	$ 1,598
Closing UCC	$ -	$ -	$ -	$ -	$ -	$ 18,161	$ 20,185

Revenue Requirement Calculation

	2010			2011			2012			2013		
Average Asset Values												
Net Fixed Software CIS	$ 4,479			$ 7,962			$ 14,927			$ 20,126		
Net Fixed Software Green Button	$ -			$ -			$ -			$ 3,057		
Net Fixed Var Compensator	$ -			$ -			$ -			$ -		
Total Net Fixed Assets	$ 4,479	$ 4,479		$ 7,962	$ 7,962		$ 14,927	$ 14,927		$ 23,183	$ 23,183	
Working Capital												
Operation Expense	$ 26,815			$ 121,627			$ (66,991)			$ 58,067		
Working Capital %	$ 4,022	$ 4,022		$ 18,244	$ 18,244		$ (10,049)	$ (10,049)		$ 6,631	$ 6,631	
Assets included in Rate Base		$ 8,501			$ 26,206			$ 4,878			$ 29,814	
Return on Rate Base												
Deemed Short Term Debt %							4.0%	$ 195		4.0%	$ 1,193	
Deemed Long Term Debt %	56.0%	$ 4,760		56.0%	$ 14,675		56.0%	$ 2,732		56.0%	$ 16,696	
Deemed Equity %	40.0%	$ 3,400		40.0%	$ 10,482		40.0%	$ 1,951		40.0%	$ 11,926	
		$ 8,161			$ 25,158			$ 4,878			$ 29,814	
Deemed Short Term Debt Rate%	1.3%			2.1%			2.1%	$ 4		2.1%	$ 25	
Weighted Debt Rate	7.6%	$ 363		4.6%	$ 672		4.6%	$ 125		4.6%	$ 765	
Proposed ROE	8.0%	$ 272		9.0%	$ 941		9.0%	$ 175		9.0%	$ 1,071	
Return on Rate Base		$ 635	$ 635		$ 1,613	$ 1,613		$ 300	$ 300		$ 1,860	$ 1,860
Operating Expenses												
Incremental Operating Expenses			$ 26,815			$ 121,627			$ (66,991)			$ 58,067
Amortization Expenses												
Amortization Expenses - Software CIS		$ 995			$ 1,991			$ 3,981			$ 6,021	
Amortization Expenses - Software Green Button		$ -			$ -			$ -			$ 679	
Amortization Expenses - Var Compensator		$ -			$ -			$ -			$ -	
Total Amortization Expenses			$ 995			$ 1,991			$ 3,981			$ 6,700
Revenue Requirement Before PILs			$ 28,445			$ 125,231			$ (62,710)			$ 66,627
Calculation of Taxable Income												
Incremental Operating Expenses			$ (26,815)			$ (121,627)			$ 66,991			$ (58,067)
Depreciation Expenses			$ (995)			$ (1,991)			$ (3,981)			$ (6,700)
Interest Expense			$ (363)			$ (672)			$ (129)			$ (789)
Taxable Income For PILs			$ 272			$ 941			$ 171			$ 1,071
Grossed up PILs			$ (1,666)			$ (805)			$ (1,998)			$ (1,989)
Revenue Requirement Before PILs			$ 28,445			$ 125,231			$ (62,710)			$ 66,627
Grossed up PILs			$ (1,666)			$ (805)			$ (1,998)			$ (1,989)
Revenue Requirement			**$ 26,779**			**$ 124,426**			**$ (64,708)**			**$ 64,638**

Revenue Requirement Calculation

	2014			2015			2016		
Average Asset Values									
Net Fixed Software CIS	$ 14,331			$ 8,260			$ 2,612		
Net Fixed Software Green Button	$ 143,922			$ 275,570			$ 232,333		
Net Fixed Var Compensator	$ -			$ 8,513			$ 16,764		
Total Net Fixed Assets	$ 158,253	$ 158,253		$ 292,343	$ 292,343		$ 251,710	$ 251,710	
Working Capital									
Operation Expense	$ 218,154			$ 72,072			$ -		
Working Capital %	$ 24,913	$ 24,913		$ 8,231	$ 8,231		$ -	$ -	
Assets included in Rate Base		$ 183,166			$ 300,574			$ 251,710	
Return on Rate Base									
Deemed Short Term Debt %	4.0%	$ 7,327		4.0%	$ 12,023		4.0%	$ 10,068	
Deemed Long Term Debt %	56.0%	$ 102,573		56.0%	$ 168,321		56.0%	$ 140,958	
Deemed Equity %	40.0%	$ 73,266		40.0%	$ 120,229		40.0%	$ 100,684	
		$ 183,166			$ 300,574			$ 251,710	
Deemed Short Term Debt Rate%	2.1%	$ 152		1.7%	$ 198		1.7%	$ 166	
Weighted Debt Rate	4.6%	$ 4,698		2.7%	$ 4,564		2.7%	$ 3,822	
Proposed ROE	9.0%	$ 6,579		9.2%	$ 11,049		9.2%	$ 9,253	
Return on Rate Base		$ 11,429	$ 11,429		$ 15,812	$ 15,812		$ 13,241	$ 13,241
Operating Expenses									
Incremental Operating Expenses			$ 218,154			$ 72,072			$ -
Amortization Expenses									
Amortization Expenses - Software CIS		$ 6,071			$ 6,071			$ 5,225	
Amortization Expenses - Software Green Button		$ 32,134			$ 68,530			$ 74,150	
Amortization Expenses - Var Compensator		$ -			$ 1,892			$ 4,146	
Total Amortization Expenses			$ 38,204			$ 76,492			$ 83,521
Revenue Requirement Before PILs			$ 267,787			$ 164,376			$ 96,762
Calculation of Taxable Income									
Incremental Operating Expenses			$ (218,154)			$ (72,072)			$ -
Depreciation Expenses			$ (38,204)			$ (76,492)			$ (83,521)
Interest Expense			$ (4,850)			$ (4,763)			$ (3,989)
Taxable Income For PILs			$ 6,579			$ 11,049			$ 9,253
Grossed up PILs			$ (38,491)			$ (32,501)			$ 22,740
Revenue Requirement Before PILs			$ 267,787			$ 164,376			$ 96,762
Grossed up PILs			$ (38,491)			$ (32,501)			$ 22,740
Revenue Requirement			**$ 229,297**			**$ 131,875**			**$ 119,503**

PILs Calculation

	2010	2011	2012	2013	2014	2015	2016
INCOME TAX							
Net Income	$ 272	$ 941	$ 171	$ 1,071	$ 6,579	$ 11,049	$ 9,253
Amortization	$ 995	$ 1,991	$ 3,981	$ 6,700	$ 38,204	$ 76,492	$ 83,521
CCA - Software CIS	$ (4,976)	$ (4,976)	$ (9,950)	$ (10,200)	$ (250)	$ -	$ -
CCA - Software Green Button	$ -	$ -	$ -	$ (3,397)	$ (157,272)	$ (181,979)	$ (28,103)
CCA - Var Compensator	$ -	$ -	$ -	$ -	$ -	$ (757)	$ (1,598)
Change in taxable income	$ (3,709)	$ (2,044)	$ (5,798)	$ (5,826)	$ (112,739)	$ (95,195)	$ 63,072
Tax Rate *(3. LDC Assumptions and Data)*	31.00%	28.25%	25.63%	25.45%	25.45%	25.45%	26.50%
Income Taxes Payable	$ (1,150)	$ (578)	$ (1,486)	$ (1,483)	$ (28,694)	$ (24,229)	$ 16,714

PILs Payable	2010	2011	2012	2013	2014	2015	2016
Change in Income Taxes Payable	$ (1,150)	$ (578)	$ (1,486)	$ (1,483)	$ (28,694)	$ (24,229)	$ 16,714
Change in OCT	$ -	$ -	$ -	$ -	$ -	$ -	$ -
PIL's	$ (1,150)	$ (578)	$ (1,486)	$ (1,483)	$ (28,694)	$ (24,229)	$ 16,714

	Gross Up	Gross Up	Gross Up	Gross Up	Gross Up	Gross Up	Gross Up
	31.00%	28.25%	25.63%	25.45%	25.45%	25.45%	26.50%

Grossed Up PILs	2010	2011	2012	2013	2014	2015	2016
Change in Income Taxes Payable	$ (1,666)	$ (805)	$ (1,998)	$ (1,989)	$ (38,491)	$ (32,501)	$ 22,740
Change in OCT	$ -	$ -	$ -	$ -	$ -	$ -	$ -
PIL's	$ (1,666)	$ (805)	$ (1,998)	$ (1,989)	$ (38,491)	$ (32,501)	$ 22,740

Carrying Costs Calculation

Date	Opening	Fund Adder	Revenue Requirement	Closing	Int. Rate	Days	Interest
Jan-10	-	-	2,232	2,232	0.55%	31	-
Feb-10	2,232	-	2,232	4,463	0.55%	28	1
Mar-10	4,463	-	2,232	6,695	0.55%	31	2
Apr-10	6,695	-	2,232	8,926	0.55%	30	3
May-10	8,926	-	2,232	11,158	0.55%	31	4
Jun-10	11,158	-	2,232	13,389	0.55%	30	5
Jul-10	13,389	-	2,232	15,621	0.89%	31	10
Aug-10	15,621	-	2,232	17,853	0.89%	31	12
Sep-10	17,853	-	2,232	20,084	0.89%	30	13
Oct-10	20,084	-	2,232	22,316	1.20%	31	20
Nov-10	22,316	-	2,232	24,547	1.20%	30	22
Dec-10	24,547	-	2,232	26,779	1.20%	31	25
Total 2010		**-**	**26,779**				**118**

	Opening	Fund Adder	Revenue Requirement	Closing	Int. Rate	Days	Interest
Jan-11	26,779	-	10,369	37,148	1.47%	31	33
Feb-11	37,148	-	10,369	47,517	1.47%	28	42
Mar-11	47,517	-	10,369	57,885	1.47%	31	59
Apr-11	57,885	-	10,369	68,254	1.47%	30	70
May-11	68,254	-	10,369	78,623	1.47%	31	85
Jun-11	78,623	-	10,369	88,992	1.47%	30	95
Jul-11	88,992	-	10,369	99,361	1.47%	31	111
Aug-11	99,361	-	10,369	109,730	1.47%	31	124
Sep-11	109,730	-	10,369	120,098	1.47%	30	133
Oct-11	120,098	-	10,369	130,467	1.47%	31	150
Nov-11	130,467	-	10,369	140,836	1.47%	30	158
Dec-11	140,836	-	10,369	151,205	1.47%	31	176
Total 2011		**-**	**124,426**				**1,236**

Carrying Costs Calculation

	Opening	Fund Adder	Revenue Requirement	Closing	Int. Rate	Days	Interest
Jan-12	151,205	-	(5,392)	145,813	1.47%	31	188
Feb-12	145,813	-	(5,392)	140,420	1.47%	29	170
Mar-12	140,420	-	(5,392)	135,028	1.47%	31	175
Apr-12	135,028	-	(5,392)	129,635	1.47%	30	163
May-12	129,635	-	(5,392)	124,243	1.47%	31	161
Jun-12	124,243	-	(5,392)	118,851	1.47%	30	150
Jul-12	118,851	-	(5,392)	113,458	1.47%	31	148
Aug-12	113,458	-	(5,392)	108,066	1.47%	31	141
Sep-12	108,066	-	(5,392)	102,674	1.47%	30	130
Oct-12	102,674	-	(5,392)	97,281	1.47%	31	128
Nov-12	97,281	-	(5,392)	91,889	1.47%	30	117
Dec-12	91,889	-	(5,392)	86,497	1.47%	31	114
Total 2012		**-**	**(64,708)**				**1,786**

	Opening	Fund Adder	Revenue Requirement	Closing	Int. Rate	Days	Interest
Jan-13	86,497	-	5,387	91,883	1.47%	31	108
Feb-13	91,883	-	5,387	97,270	1.47%	28	104
Mar-13	97,270	-	5,387	102,656	1.47%	31	121
Apr-13	102,656	-	5,387	108,043	1.47%	30	124
May-13	108,043	-	5,387	113,429	1.47%	31	135
Jun-13	113,429	-	5,387	118,816	1.47%	30	137
Jul-13	118,816	-	5,387	124,202	1.47%	31	148
Aug-13	124,202	-	5,387	129,589	1.47%	31	155
Sep-13	129,589	-	5,387	134,975	1.47%	30	157
Oct-13	134,975	-	5,387	140,362	1.47%	31	169
Nov-13	140,362	-	5,387	145,748	1.47%	30	170
Dec-13	145,748	-	5,387	151,135	1.47%	31	182
Total 2013		**-**	**64,638**				**1,709**

1

Carrying Costs Calculation

	Opening	Fund Adder	Revenue Requirement	Closing	Int. Rate	Days	Interest
Jan-14	151,135	-	19,108	170,243	1.47%	31	189
Feb-14	170,243	-	19,108	189,351	1.47%	28	192
Mar-14	189,351	-	19,108	208,459	1.47%	31	236
Apr-14	208,459	-	19,108	227,567	1.47%	30	252
May-14	227,567	-	19,108	246,675	1.47%	31	284
Jun-14	246,675	-	19,108	265,783	1.47%	30	298
Jul-14	265,783	-	19,108	284,891	1.47%	31	332
Aug-14	284,891	-	19,108	303,999	1.47%	31	356
Sep-14	303,999	-	19,108	323,107	1.47%	30	367
Oct-14	323,107	-	19,108	342,215	1.47%	31	403
Nov-14	342,215	-	19,108	361,323	1.47%	30	413
Dec-14	361,323	-	19,108	380,431	1.47%	31	451
Total 2014		**-**	**229,297**				**3,774**

	Opening	Fund Adder	Revenue Requirement	Closing	Int. Rate	Days	Interest
Jan-15	380,431	-	10,990	391,421	1.47%	31	475
Feb-15	391,421	-	10,990	402,411	1.47%	28	441
Mar-15	402,411	-	10,990	413,400	1.47%	31	502
Apr-15	413,400	-	10,990	424,390	1.10%	30	374
May-15	424,390	-	10,990	435,379	1.10%	31	396
Jun-15	435,379	-	10,990	446,369	1.10%	30	394
Jul-15	446,369	-	10,990	457,358	1.10%	31	417
Aug-15	457,358	-	10,990	468,348	1.10%	31	427
Sep-15	468,348	-	10,990	479,338	1.10%	30	423
Oct-15	479,338	-	10,990	490,327	1.10%	31	448
Nov-15	490,327	-	10,990	501,317	1.10%	30	443
Dec-15	501,317	-	10,990	512,306	1.10%	31	468
Total 2015		**-**	**131,875**				**5,210**

Carrying Costs Calculation

	Opening	Fund Adder	Revenue Requirement	Closing	Int. Rate	Days	Interest
Jan-16	512,306	-	9,959	522,265	1.10%	31	477
Feb-16	522,265	-	9,959	532,223	1.10%	29	455
Mar-16	532,223	-	9,959	542,182	1.10%	31	496
Apr-16	542,182	-	9,959	552,140	1.10%	30	489
May-16	552,140	-	9,959	562,099	1.10%	31	514
Jun-16	562,099	-	9,959	572,058	1.10%	30	507
Jul-16	572,058	-	9,959	582,016	1.10%	31	533
Aug-16	582,016	-	9,959	591,975	1.10%	31	542
Sep-16	591,975	-	9,959	601,933	1.10%	30	534
Oct-16	601,933	-	9,959	611,892	1.10%	31	561
Nov-16	611,892	-	9,959	621,850	1.10%	30	552
Dec-16	621,850	-	9,959	631,809	1.10%	31	579
Total 2016		**-**	**119,503**				**6,239**

	Opening	Fund Adder	Revenue Requirement	Closing	Int. Rate	Days	Interest
Jan-17	631,809	-	-	631,809	1.10%	31	590
Feb-17	631,809	-	-	631,809	1.10%	28	533
Mar-17	631,809	-	-	631,809	1.10%	31	590
Apr-17	631,809	-	-	631,809	1.10%	30	571
May-17	631,809	-	-	631,809	1.10%	31	-
Jun-17	631,809	-	-	631,809	1.10%	30	-
Jul-17	631,809	-	-	631,809	1.10%	31	-
Aug-17	631,809	-	-	631,809	1.10%	31	-
Sep-17	631,809	-	-	631,809	1.10%	30	-
Oct-17	631,809	-	-	631,809	1.10%	31	-
Nov-17	631,809	-	-	631,809	1.10%	30	-
Dec-17	631,809	-	-	631,809	1.10%	31	-
Total 2017		**-**	**-**				**2,285**

Climate Change Projects Disposition Rate Rider

Description		Amount
Revenue Requirement - 2010	$	26,779
Revenue Requirement - 2011	$	124,426
Revenue Requirement - 2012	$	(64,708)
Revenue Requirement - 2013	$	64,638
Revenue Requirement - 2014	$	229,297
Revenue Requirement - 2015	$	131,875
Revenue Requirement - 2016	$	119,503
Revenue Requirement - 2017	$	-
Revenue Requirement - 2018	$	-
Revenue Requirement - 2019	$	-
Total Revenue Requirement	$	631,809
Rate Adder Collected	$	-
Carrying Cost / Interest	$	22,356
1 Proposed Climate Change Projects Disposition Recovery	$	654,165

Rate Rider Start Date	May 1, 2017
Rate Rider End Date	April 30, 2018
Number of Months	12

Customer Class	Number of Customers	IRR Allocation	Disposition Recovery	Monthly Rate Rider
RESIDENTIAL	142,509	90.9%	$ 594,453	**$ 0.35**
GENERAL SERVICE LESS THAN 50 kW	12,749	8.1%	$ 53,180	**$ 0.35**
GENERAL SERVICE 50 TO 4,999 KW SERVICE CLASSIFICATION	1,561	1.0%	$ 6,511	**$ 0.35**
GENERAL SERVICE 1,000 TO 4,999 KW (CO-GENERATION) SERVICE CLASSIFICATION	4	0.0%	$ 17	**$ 0.35**
STANDBY POWER SERVICE CLASSIFICATION	-	0.0%	$ -	**$ -**
LARGE USE SERVICE CLASSIFICATION	1	0.0%	$ 4	**$ 0.35**
STREET LIGHTING SERVICE CLASSIFICATION	35,912	0.0%	$ -	**$ -**
SENTINEL LIGHTING SERVICE CLASSIFICATION	599	0.0%	$ -	**$ -**
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	1,537	0.0%	$ -	**$ -**
1 Total	194,872	100.0%	$ 654,165	

Asset Accounting Summary

Fixed Assets

Software CIS	30,353
Software Green Button	370,751
Var Compensator	22,540
Asset 4	-
Asset 5	-
Total	423,643

Accumulated Depreciation

Software CIS	(30,353)
Software Green Button	(175,493)
Var Compensator	(6,038)
Asset 4	-
Asset 5	-
Total	(211,883)

Addition To Net Fixed Assets	**211,760**

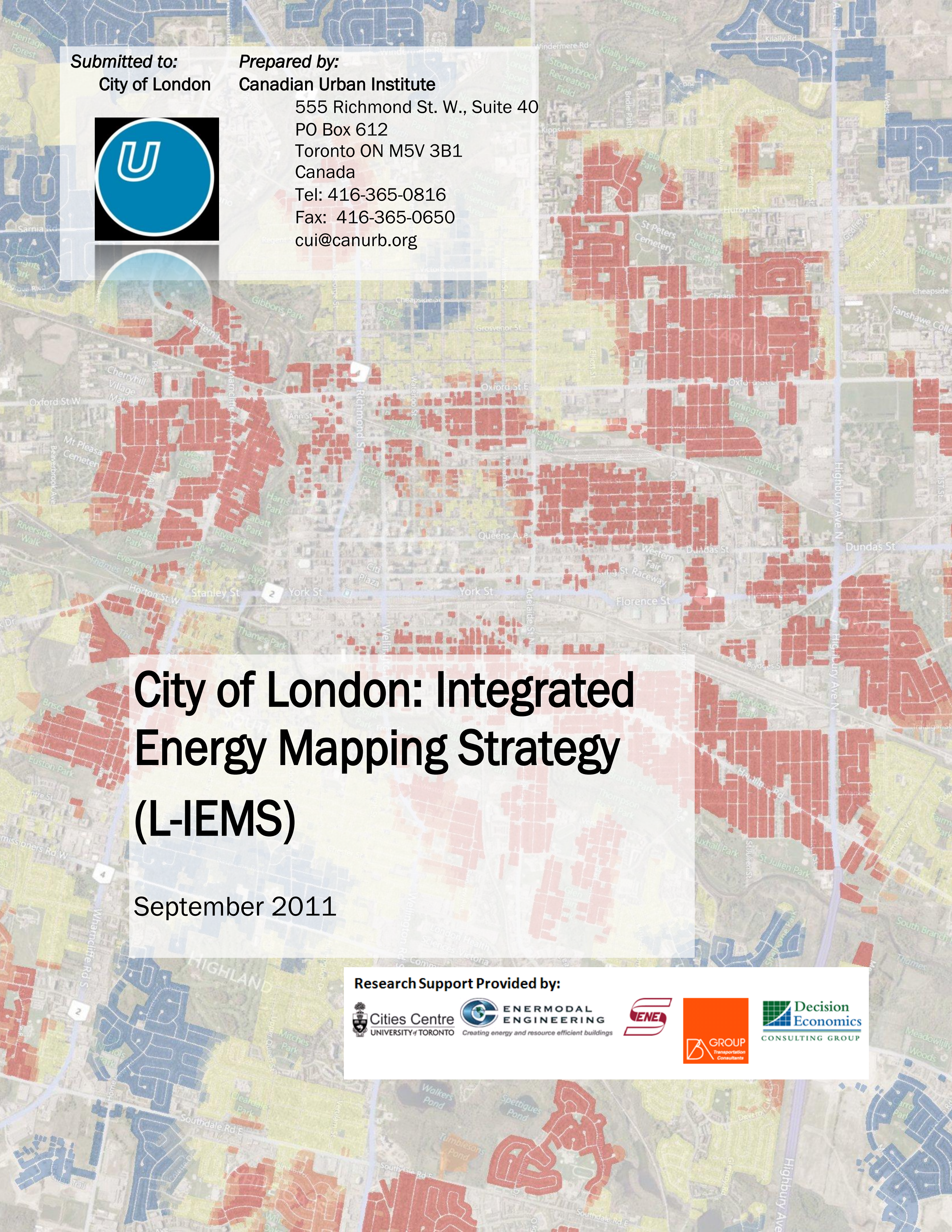
Amortization Expense

2010 Amortization Expense	
Software CIS	995
Software Green Button	-
Var Compensator	-
Asset 4	-
Asset 5	-
Total 2010 Amortization Expense	995
2011 Amortization Expense	
Software CIS	1,991
Software Green Button	-
Var Compensator	-
Asset 4	-
Asset 5	-
Total 2011 Amortization Expense	1,991
2012 Amortization Expense	
Software CIS	3,981
Software Green Button	-
Var Compensator	-
Asset 4	-
Asset 5	-
Total 2012 Amortization Expense	3,981
2013 Amortization Expense	
Software CIS	6,021
Software Green Button	679
Var Compensator	-
Asset 4	-
Asset 5	-
Total 2013 Amortization Expense	6,700

2014 Amortization Expense	
Software CIS	6,071
Software Green Button	32,134
Var Compensator	-
Asset 4	-
Asset 5	-
Total 2014 Amortization Expense	38,204
2015 Amortization Expense	
Software CIS	6,071
Software Green Button	68,530
Var Compensator	1,892
Asset 4	-
Asset 5	-
Total 2015 Amortization Expense	76,492
2016 Amortization Expense	
Software CIS	5,225
Software Green Button	74,150
Var Compensator	4,146
Asset 4	-
Asset 5	-
Total 2016 Amortization Expense	83,521

File Number:	EB-2016-0091
Exhibit:	9
Tab:	1
Schedule:	11
Date Filed:	August 26, 2016

APPENDIX 4 OF 5
APPENDIX 9D CITY OF LONDON INTEGRATED ENERGY MAPPING STRATEGY



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City of London: Integrated Energy Mapping Strategy (L-IEMS)

September 2011

Research Support Provided by:

Cities Centre UNIVERSITY of TORONTO
ENERMODAL ENGINEERING Creating energy and resource efficient buildings
ENE
BA GROUP Transportation Consultants
Decision Economics CONSULTING GROUP

City of London Integrated Energy Mapping Strategy (L-IEMS)

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Preface

About the Canadian Urban Institute

As Canada's applied urban policy institute dedicated to identifying, developing and delivering policy and planning solutions to enable urban regions to thrive and prosper, the Canadian Urban Institute (CUI) is engaged in Canada's movement to advance market transformation for sustainable communities and to encourage the application and integration of energy into the decision-making process at the municipal level.

Integrated Energy Mapping for Ontario Communities (IEMOC) Initiative

In late 2009, the CUI received support from the Ontario Power Authority (OPA), the CanmetENERGY division of Natural Resources Canada (NRCan) and the Ontario Centres of Excellence (OCE) to launch the Integrated Energy Mapping for Ontario Communities (IEMOC) initiative. The IEMOC initiative is working with the cities of Guelph, Hamilton, Barrie, and London to analyze the impact of population growth, employment growth, land-use, and transportation decisions on existing and future energy consumption and supply.

Five activities are being undertaken in each participating community:

- evaluate energy reduction opportunities for new and existing buildings;
- review the application of cost-effective alternative technologies and renewable fuels;
- assess the potential to reduce the impact of transportation related energy use;
- visualize energy use of buildings and transportation using maps through Geographic Information Systems (GIS); and,
- develop a tool to monitor, evaluate and verify progress towards meeting energy and greenhouse gas objectives.

Each community is receiving the following reports and models:

- an integrated energy mapping strategy;
- geocoded energy maps for visualizing energy use and scenarios; and,
- integrated energy mapping model and financial assessment.

The City of London was identified as a recipient for the IEMOC initiative to evaluate opportunities to meet the City's greenhouse gas emission reduction goals.

Executive Summary

London is the final community to apply the Canadian Urban Institute's (CUI) Integrated Energy Mapping approach as part of the Integrated Energy Mapping for Ontario Communities (IEMOC) initiative. For this project, the City of London partnered with local utilities London Hydro, Union Gas and London District Energy (Veresen) and CUI to evaluate potential strategies that could result in the reduction of energy use across London and contribute to meeting greenhouse gas (GHG) objectives.

Traditional Energy Planning in Ontario

Conventionally, energy supply planning has been undertaken by provincial agencies and utilities. Typically, energy infrastructure such as electricity for power in buildings and natural gas for space heating and domestic hot water is matched to demand once the investment in houses, roads, vehicles and municipal infrastructure have been made by a community, private developer or owner. The concept of integrated energy planning involves building on the interdisciplinary opportunities by integrating physical components from multiple sectors, including energy supply and distribution; transportation; housing and building industry; water; waste management and other local community services; and land use and community form. This requires communication and collaboration across City departments as well as shared access to energy data.

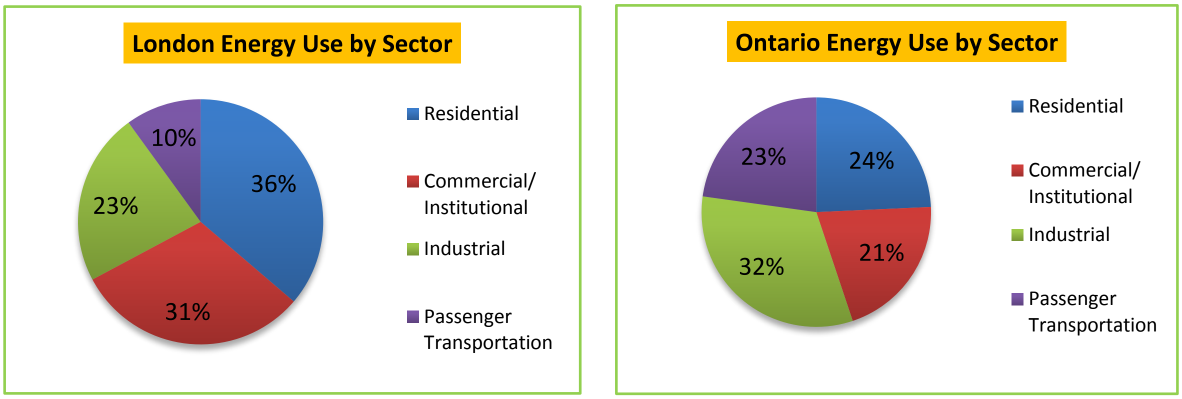
Taking advantage of federal and provincial programs and international networks the City of London has already established itself as a leader in energy planning. Key initiatives include the City's Air Quality Strategy: *"Moving Forward Locally",* the Mayor's Sustainable Energy Council (MSEC), the London Energy Efficiency Partnership (LEEP) Project and the Technology Adoption Pilot as well as the Smart Moves 2030 Transportation Master Plan and supporting activities which are currently under development. The City is also currently partnering with the Ontario Power Authority (OPA) to identify how new planning tools and policies can be applied to advancing energy efficiency and renewable energy.

Integrated energy mapping assembles a wide range of data inputs that are used to develop a spatially distributed baseline for energy consumption in a community and evaluate the long-term effect of energy reduction strategies. Preparing this integrated database and analysis can help the City to advance and prioritize local energy planning initiatives in London.

Current Energy Use in London

Figure 1 illustrates the breakdown of total energy use by sector in London and in Ontario. In London, a higher proportion of energy is consumed in the residential and commercial sectors compared to the provincial totals (36% and 31% respectively for London and 24% and 21% for Ontario). The industrial and personal transportation sectors consume less energy proportionally than the provincial total, constituting 23% and 10% of the City's energy use respectively compared to 32% and 23% for the province. In total London consumes approximately 11,700,000 GJ/yr of electricity and 24,000,000 GJ/yr of natural gas for buildings, and an additional 4,000,000 GJ/yr for personal transportation fuels resulting in a total of 2,100,000 tonnes CO_2 emitted per year.

FIGURE 1 LONDON AND ONTARIO ENERGY USE BY SECTOR



Impacts of Growth

To accommodate an increase in population growth of 70,500 people by 2031, or a 1% annual growth rate, it is projected that an additional 20% (2,309,000 GJ/yr) of electricity and 14% of (3,484,000 GJ/yr) natural gas will be required to meet the energy demands of London assuming business as usual development practices. Increases in energy for personal transportation are also expected with an overall growth in energy for transportation of 14% (567,000 GJ/yr). It is anticipated that this will result in a total of 46,000,000 GJ/yr of energy consumption and 2,000,000 tonnes CO_2/yr of associated emissions considering the projected emissions reductions associated with power generation.

In all circumstances, the average annual cost of energy is expected to increase as well. Currently, the total cost for all electricity and natural gas used in buildings and fuel for personal transportation in London is estimated at $427 million per year. With the full build out for London to accommodate the expected population, employment, and transportation demands, it can be expected that the cost of supplying energy in London will increase by about 17% to $500 million per year assuming no increase in electricity, natural gas, gasoline, or diesel prices. Factoring in an escalation rate of 2% applied to commodity costs of electricity, increases in natural gas prices as projected by GLJ Petroleum Consultants as well as a 5% escalation rate for gasoline and diesel,[1] the anticipated annual energy cost per person in 2031 is projected to increase by 85% from 2008 estimated expenditures to $2,200 per capita per year. Estimated and projected energy costs for London are based on commodity costs only and do not include HST, fuel tax, distribution or debt retirement fees.

If the City of London implements all identified building and personal transportation improvements identified in the Ultra High Efficiency Scenario evaluated for London it is anticipated that the city can reduce its energy use by 14,600,000 GJ (32%) and reduce emissions by 700,000 tonnes CO_2/yr compared with Business as Usual.

Comparing Residential Built Form

Building energy use and efficiency can vary based on building size, height, age, heating equipment, and other attributes. Figure 2 illustrates the variation in electricity and natural

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[1] Based on average annual fuel price increase over 2001 – 2011

gas use (GJ/m²) in existing residential buildings in London broken down by age of building construction. Here it can be seen that energy intensity for low density residences (i.e., single family and semi detached homes) is decreasing in newer construction. It can also be seen that energy use in medium density (row housing) and high density (apartments) varies depending on the year built, and electricity use in newer apartments is increasing.

Figure 2 Existing Building Stock Performance

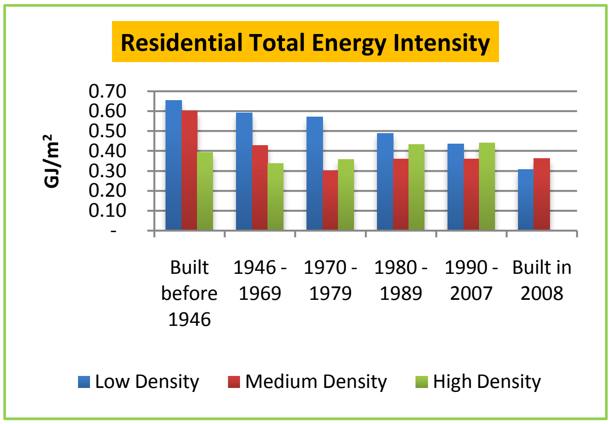
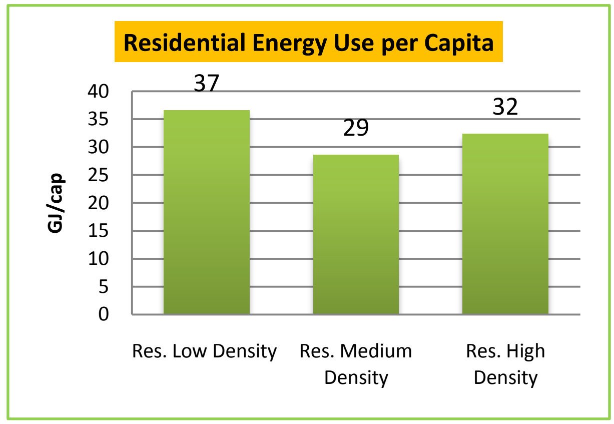


Figure 3 Modeled New Development



Considering unit sizes and number of people living in average units in new housing developments, it is anticipated that the most efficient type of residential housing will be mid-rise. Figure 3 illustrates the projected variation in energy use per capita by residential building type for new construction.

Within the low density building type, there is an opportunity to use energy mapping to identify areas of high natural gas and electrcity consumption in London where further study for retrofit opportunities could be targeted. Figures 4 and 5 illustrate this opportunity.

Figure 4 Low-Rise Residential Natural Gas Hot Spots

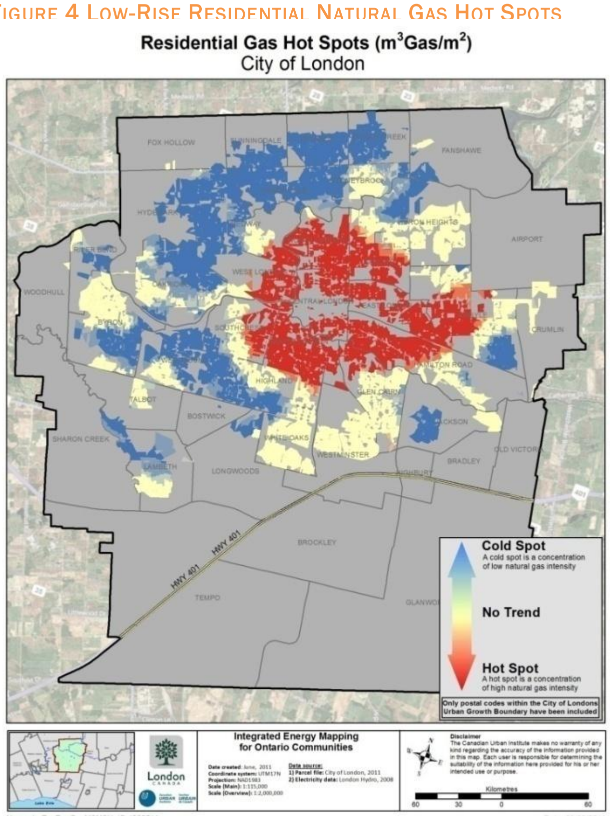
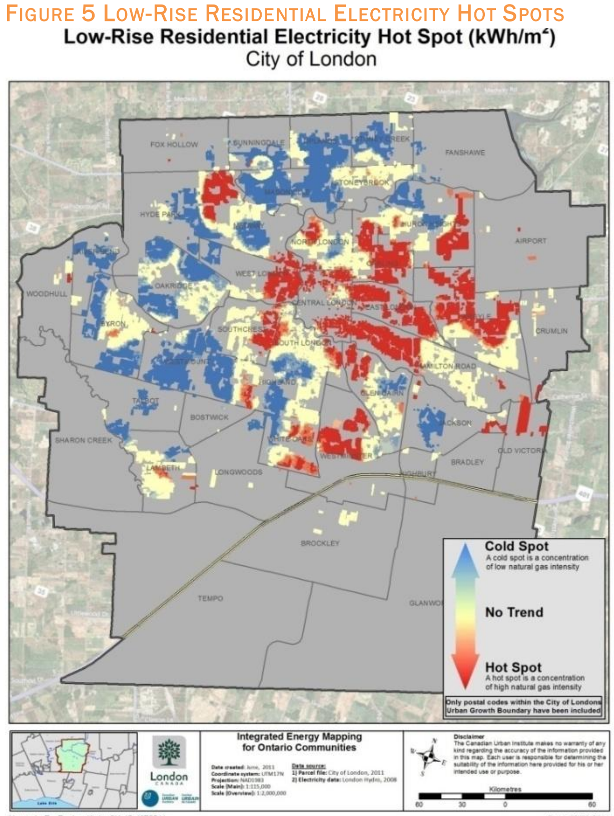


Figure 5 Low-Rise Residential Electricity Hot Spots



Economic Opportunity

An assessment of the financial performance for each of the energy efficiency building improvements by building type was undertaken. The assessment involved evaluating High Efficiency and Ultra High Efficiency Scenarios for building improvements against the Business as Usual Scenario. Building retrofit costs were calculated using Marshall Valuation Service cost data and should be considered average for all buildings within an evaluated building type across the City.

Across all building types evaluated as part of the L-IEMS, building efficiency improvements that had the highest financial performance in terms of internal rate of return (IRR) were high efficiency new construction for offices, low density institutional buildings and industrial buildings as illustrated in Figure 4. Retrofitting existing industrial buildings to 25% better than current performance on average also proved to be financially viable with an IRR on improvement costs greater than 8%.

One can also measure investment feasibility by calculating the payback period. High efficiency new construction for office, low density institutional and industrial buildings were found to meet the acceptable payback period of 7 years as illustrated in Figure 5.

FIGURE 6 HIGH EFFICIENCY BUILDING IMPROVEMENTS IRR

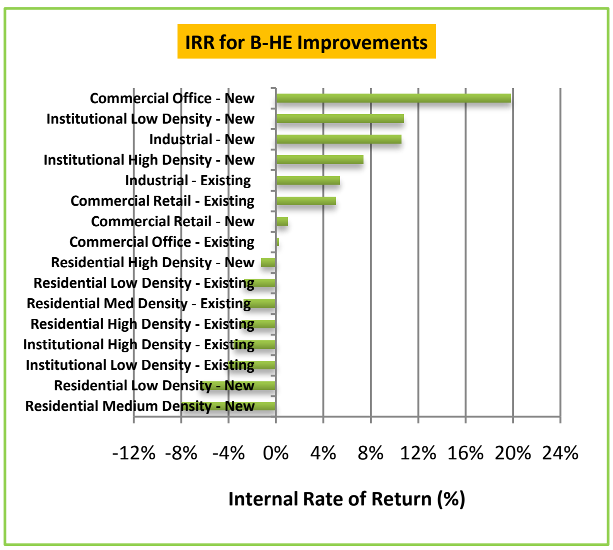
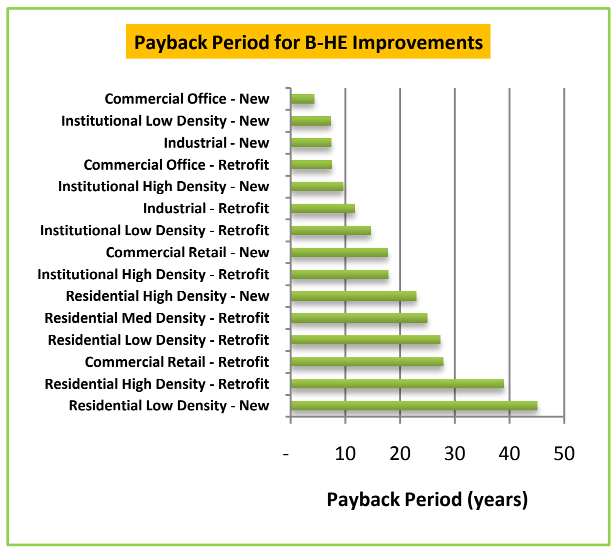


FIGURE 7 HIGH EFFICIENCY BUILDING IMPROVEMENTS PAYBACK



Though not evaluated for London, retrofitting single family homes built prior to 1940's in the City of Hamilton to 10% better than existing performance on average resulted in an IRR of 12% based on building simulations. Targeting conservation demand management (CDM) and demand side management (DSM) programs at older homes in London could result in similar returns.

Table 1 below summarizes the economic performance and estimated maximum potential to offset energy and carbon in London using renewable technologies.

TABLE 1 ECONOMIC EVALUATION OF ALTERNATIVE FUELS AND TECHNOLOGIES

Technology	Energy Source Displaced	Total Potential Capital Cost	Rate of Return with FIT Pricing	Rate of Return without FIT Pricing	Maximum Potential Energy Displaced (GJ)	Maximum Potential GHG Reduced Tonnes (CO_2e/yr)
Photovoltaic – FIT	Electricity	$3,963,000,000	8%	-6%	3,390,000	25,000
Photovoltaic – microFIT	Electricity	$3,963,000,000	18%	-6%	3,390,000	25,000
Biomass - FIT	Electricity	$493,000,000	19%	7%	2,825,000	21,000
Wind - FIT	Electricity	$387,000,000	11%	4%	565,000	4,000
Wind - microFIT	Electricity	$387,000,000	2%	-3%	565,000	4,000
Solar Air	Natural Gas	$743,000,000	N/A	-2%	4,431,000	249,000
District Energy – connecting existing buildings downtown	Natural Gas and Electricity	$98,000,000	N/A	4%	1,008,000	-29,000
Solar Hot Water - microFIT	Natural Gas	$6,845,000,000	N/A	-9%	17,725,000	994,000
GeoExchange - microFIT	Natural Gas	$3,682,000,000	N/A	No return projected.	23,679,000	1,278,000

While the financial case can be made for connecting both existing buildings and projected new development to a DE CHP system, according to published plans to green the provincial electricity grid, using natural gas as a fuel source to generate electricity may result in increased emissions compared with a conventional system over the long term.[2] It should be noted that, consistent with the provincial direction to green the grid, proponents of district energy support transitioning away from reliance on natural gas as a feedstock for base loads on the basis that a district energy system can be adapted to accommodate renewable energy sources.

[2] For the purposes of this analysis, factors presented in OPA's 2010 District Energy Research Report have been used. Further review of the applicability of these factors to London could produce alternate results.

Personal Transportation

If all demand improvements were achieved for the Transportation Ultra High Efficiency case evaluated for London, including vehicle trip reductions and increases in walking, cycling and transit then London's total annual kilometres travelled by personal vehicle would be reduced by 18%, resulting in an estimated 15% reduction in both energy use from personal transportation and associated emissions.

Incorporating potential vehicle efficiency improvements including 80% of gas powered personal vehicles being replaced with hybrids and another 20% with electric vehicles or plug-in hybrids the associated reduction in transportation energy and GHGs would be 54% and 57% respectively compared with BAU.

Figures 6 and 7 review the impact of TDM strategies and vehicle technology and fuel efficiencies for each transportation scenario evaluated. TDM measures and vehicle technology and fuel efficiencies could achieve a total reduction of 2,452,000 GJ compared with BAU transportation energy use in the T-UHE case. This corresponds with a reduction of 180,000 tonnes of CO_{2e} savings**.**

FIGURE 6 TRANSPORTATION DEMAND SCENARIOS

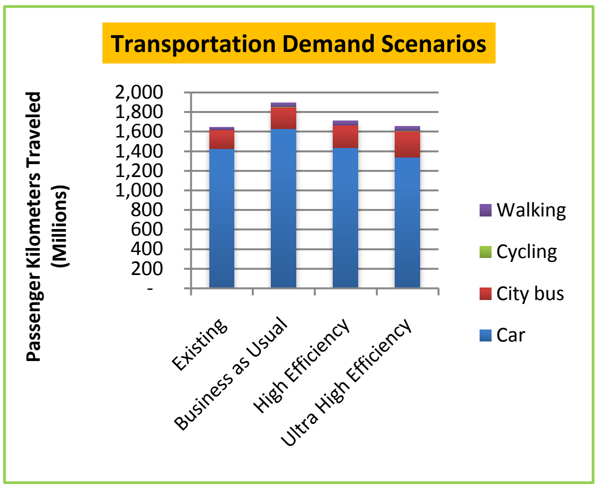
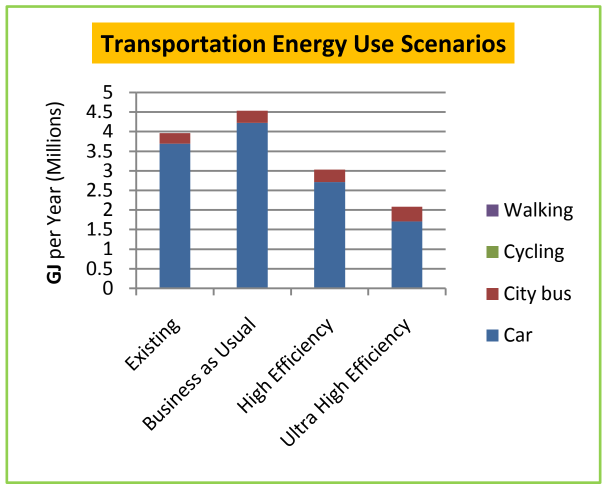


FIGURE 7 TRANSPORTATION ENERGY SCENARIOS



Immediate Steps to Advance Energy Efficiency

The following three immediate steps will help London to further these initiatives:

Step One: Develop an Action Plan with Key Stakeholders and Utilities

Action: Prepare a consolidated action plan that sorts out who among the energy players ought to do what in London's energy future and create a road map for advancing selected energy/GHG activities.

Action: Prepare indicators to measure progress towards targets. Indicators should capture the contribution of all energy programs, projects and policies underway in London. Important metrics could include energy used for buildings (GJ/yr or GJ/m^2/yr), energy used for transportation (GJ/yr, GJ/VKT, GJ/cap/yr), and capacity or energy generated from renewable fuels and local generations (kW, GJ/yr).

Action: Use the Mayor's Sustainable Energy Council (MSEC) to move forward energy efficiency and GHG actions.

Step Two: Building on Information for Integrated Energy Mapping

Action: Work with London District Energy to apply available energy information to target system expansion in downtown London.

Action: Incorporate urban forest data into energy mapping to produce shade target map.

Action: Work with local utilities to resolve potential outliers identified during integrated energy mapping exercise.

Step Three: Invest in the Resources and Knowledge to Advance Energy Efficiency

Action: London should establish a position to manage the development and delivery of actions with respect to community energy. These initiatives are currently managed by the City of London's Air Quality Manager. This City should also consider adjusting the title and terms of this position to reflect this responsibility. In other municipalities across Ontario and Canada this person is called a community energy manager.

Action: London should collaborate with utilities to determine how to optimize the use of alternative energy sources (consider preparing an energy resource map – biomass, waste heat capture, conversion of local syngas sources etc).

1. Introduction

London is the final community to apply the Canadian Urban Institute's (CUI) Integrated Energy Mapping approach as part of the Integrated Energy Mapping for Ontario Communities (IEMOC) initiative. For this project, the City of London partnered with local utilities London Hydro, Union Gas and London District Energy (Veresen) and retained the CUI to evaluate potential strategies that could result in the reduction of energy use across London and contribute to meeting greenhouse gas (GHG) objectives. IEMOC is evaluating energy reduction strategies for buildings, automobiles, and transit, as well as the use of renewable energy sources that are appropriate for the local climate, residents, and businesses.

This report:

- Explains how integrated energy mapping was applied in London;
- Evaluates current energy use for the London;
- Reviews the impact of energy and greenhouse gas emissions reductions opportunities associated with London's built-form;
- Explores the cost effectiveness of alternative technologies and renewable fuels that can be implemented in London;
- Assesses the impact of transportation energy use and greenhouse gas emissions reduction strategies; and,
- Outlines suggested next steps to advance with the process of identifying and implementing energy efficiency actions.

The *City of London Integrated Energy Mapping Strategy* (L-IEMS) contributes to the ongoing work underway at the City of London to become a competitive, energy efficient and competitive community. The L-IEMS is intended to inform the development of an action plan and does not evaluate the potential tools or policies required to implement energy reduction strategies outlined as part of the L-IEMS.[3]

L-IEMS Report Structure

Chapter 1 of the report consists of a brief discussion about the importance of energy and explains how the integrated energy mapping process was applied in London.

Chapter 2 provides an overview of how energy is consumed in London and outlines how energy demands and GHG emissions could change over time. The evaluation is divided into major sectors including residential, commercial and industrial buildings and transportation. In this section, baseline maps for energy use in London are introduced.

Chapter 3 reviews energy efficiency strategies to reduce energy and associated GHG emissions in London's built form. The section includes the evaluation of alternative technologies and renewable fuels to help meet the energy demands of London's built environment.

Chapter 4 evaluates the impacts of opportunities to reduce energy and emissions from transportation in London. This chapter explores the impacts of reducing the distance traveled by London residents using personal vehicles and how the use of alternative transportation technologies and renewable fuels can help to reduce energy use and lower GHG emissions.

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[3]The L-IEMS does not incorporate the likelihood of market potential (uptake) of the energy strategies evaluated. A high level of change in human behaviour would be required to ensure energy strategies are effective in terms of reducing energy use associated with built form and transportation patterns.

Chapter 5 summarizes insights about where London might focus with partners and local utilities for improving energy efficiency and identifies three next steps for advancing energy efficiency.

Methodology

Appendix A sets out the methodology and assumptions applied for the L-IEMS. Appendix B identifies the economics of capital project decision-making used for the IEMOC initiative.

How to Use the L-IEMS

The L-IEMS can be used to compare the cost, energy and emissions impacts of energy efficiency strategies for London. This study quantifies the impacts of efficiency strategies on different sectors including residential, commercial and industrial buildings, energy supply and transportation. This study can be used to understand the impact of sector based efficiency strategies on city wide energy use and emissions. It is not intended to predict the success of program implementation. Additional targeted policy analyses need to be undertaken to understand the potential market uptake of specific efficiency and transportation demand management (TDM) or transportation efficiency programs.

The L-IEMS and supporting spread-sheet tool can be used to continue to test the impact of different efficiency scenarios, energy prices, interest rates, land-use factors, and other factors, as well as generate additional maps.

1.1. The Role of Energy in Cities

Energy is central to the daily functions and actions of every community. As part of this study, CUI worked with the City of London and local utilities to understand the uses of electricity and natural gas for conditioning buildings and to estimate the fuel use for transportation.

What is Energy Efficiency and Why Is It Necessary for Energy Efficiency?

As population and employment in a city grow, more fuel and materials are needed for generation, transmission and distribution of energy. Taking steps to reduce the amount of electricity or natural gas that is used in a home or business helps to lower individual utility costs and conserve natural resources. Activities that contribute to reducing gasoline consumption, such as using alternative technologies to propel vehicles or reducing distance traveled for a routine trip, all contribute to reduce energy use and GHG emissions.

Simply put, energy efficiency means using less energy to accomplish the same activity or goal. While Canada's total energy use has gone down over the last decade largely due to energy efficiency improvements, energy use in urban environments has increased by over 20 percent.[4]

The motivating drivers for incorporating energy efficiency as part of short-term and long-term community planning and economic development include:

Response to climate change. Growing concern about climate change is driving interest in solutions that can achieve the GHG reductions that are needed to stabilize global climate conditions. As part of the response to climate change, the broader building community and local public sector are now exploring the role of energy efficiency and community energy systems to improve adaptation and mitigation capacity of the built form. Communities have also

[4] ICES Municipal Policy Tool-Kit. September 2010.

started to consider how the use of energy efficiency can contribute to climate change adaptation.

Energy and land availability. Community development patterns over the past several decades in Canada have been driven by the availability of low-cost energy and land resources. Energy efficiency is now considered an important component of achieving successful long-term growth objectives for a community.

Energy security and community affordability. Energy is increasingly viewed as a strategic resource within communities, due to the risks and costs of service disruptions. This creates a desire for secure and reliable energy which has become an emerging driver for energy efficiency. Energy efficiency has also been acknowledged to attract and retain jobs by creating a more competitive investment environment for businesses to operate, while also maximizing the use of local energy sources and reducing reliance on centralized forms of energy for electricity and the distribution of natural gas. The potential economic benefits of energy efficiency are discussed later in the L-IEMS.

Transitioning to new energy sources. Modern energy and transportation systems have a direct impact on how energy is consumed. Fossil fuel deposits are by far the highest concentration of high quality energy. The way electricity and other sources of heat are produced today results in power densities that are one to three orders of magnitude higher than regular power densities required to operate buildings and cities.[5] Canada's built environment is designed around access to inexpensive fossil fuels. Reducing reliance on fossil fuels will require creating a built environment that is energy efficient, captures waste heat and energy, and supports renewable and alternative sources of technologies.

How Have Communities Traditionally Planned for Energy?

Energy supply planning continues to be undertaken by provincial agencies and utilities. Typically, energy infrastructure such as electricity for power in buildings and natural gas for space heating and domestic hot water is matched to demand once the investment in houses, roads, vehicles and municipal infrastructure have been made by a community, private developer or owner. At the same time, the decisions related to land-use, roadway design, recycling, solid waste disposal, water supply, sewage treatment, and building design among others, all work to create the energy profile of a community and influence how energy efficiency can be achieved.

Integrated Energy Planning

Communities in Canada account for about 60% of Canada's energy consumption. In recent years, communities have begun to identify opportunities for improving their energy performance through cross-cutting sector integration while enhancing quality of life and realizing financial benefits. The concept of integrated energy planning involves building on the interdisciplinary opportunities by integrating physical components from multiple sectors, including energy supply and distribution; transportation; housing and building industry; water; waste management and other local community services; and land use and community form.

This progressive shift in thinking was launched through a study by Mark Jaccard,

[5] Vaclav Smil. 2006. 21st "Century Energy: Some Sobering Thoughts". OECD Observer Vol. 258/59 pp 22-23

Lee Failing and Trent Berry in the early 1990's. The study put forward that density and land-use patterns, which determine size and type of buildings, commuting distances, transportation modes, and energy supply systems, influence the energy profile of a community and the ability to achieve energy objectives.

This relationship is outlined in Table 1-1, which illustrates how land-use decisions made today can have a direct and long-term impact on decisions related to buildings and equipment in the near and distant future.

TABLE 1-1 ENERGY DECISION MAKING HIERARCHY

Energy Decision Making Hierarchy			
Energy-Related Decisions	Dimensions		
	Time	Space	Private/Public
Land-use and infrastructure	Years to decades	A lot	Public
Building and site design	1 to 3 years	Moderate	Public/Private
Energy-use equipment	Less than 1 year	Little	Private

Source: Mark Jaccard, Lee Failing and Trent Berry. 1997. "From Equipment to Infrastructure: Community Energy Management and Greenhouse Gas Emissions Reduction." Energy Policy.Vol. 25 No. 13 pp. 1065-1074.

An important finding of the study was that the best long-term opportunity to influence energy use and associated GHG emissions starts with the decisions made early on about land-use, transportation and other systems wide services, such as water use, water treatment and the handling of municipal waste. A similar study was performed by the Quality Urban Energy Systems of Tomorrow (QUEST) and identified a similar potential long-term energy efficiency opportunity –largely through the reduction in daily trips–of15-20% in potential energy reductions through better integrated energy planning decision making.[6]

Even with these insights, few communities at the municipal level actively plan to reduce energy demand and encourage energy efficiency when evaluating long-range planning for people, employment, and transportation. Achieving sustainable integrated energy planning involves linking the actions and decisions that create the energy profile of a community, with the way people use and interact with energy on a daily basis.

Advancing Energy Efficiency: Opportunities for London

The City of London is already advancing energy efficiency and the reduction of GHG emissions. Since 2003, the City's Air Quality Strategy, *"Moving Forward Locally,"* has encouraged the advancement of energy conservation and energy efficiency as one of the central approaches to effectively deal with air pollution and climate change. At the same time, the Mayor's Sustainable Energy Council (MSEC) has actively undertaken to engage local energy experts to support new local research, technology development, and the adoption of green energy investments. As a result of these activities, London has been acknowledged as a centre of energy efficiency excellence, and has laid the foundation for a new "green economy."

The City is also actively working with local utilities, developers and other levels of government to advance energy efficiency. A nationally recognized activity is the assistance provided to the development of the London Energy Efficiency Partnership (LEEP) Project and the Technology Adoption

[6] M.K. Jaccard and Associates, Inc. The Capacity for Integrated Community Energy Solutions (ICES) Policies to Reduce Urban Greenhouse Gas Emissions. Produced for QUEST. 2010 August.

Pilot. Both of these initiatives have led to providing local home builders in the London areas with a tool-kit of solutions for advancing energy efficiency. Ten discovery homes (new construction and renovation) are to be built in London to showcase the LEEP-TAP technologies.

The City of London participates in the Federation of Canadian Municipalities (FCM) Partners for Climate Protection (PCP), and has reaffirmed the long-term interest of the community to actively address climate change and local community competitiveness. This has also included several other activities, such as the RETHINK Energy London Consultation and Engagement Process to advance development of an updated community energy and climate change action plan. As an initial step for the PCP program, the City of London has developed a comprehensive GHG program, identified activities that residents and businesses can do to reduce GHG emissions and undertaken a range of pilot programs to reduce energy use in buildings and from transportation activities in London.

City Council has also endorsed other initiatives to advance energy efficiency, including proposals for bus rapid transit and increasing public transit service across the City. The City is also updating its transportation strategy, through its Smart Moves 2030 Transportation Master Plan and supporting activities.

The City is also actively evaluating how new planning tools and policies can be applied to advancing energy efficiency and renewable energy. Recently, the City completed a report, *London Green Incentives,* with support from the OPA that examines the types of incentives and policies that can be used to advance green development for greenfields, urban redevelopment and building level retrofits. This work is expected to contribute to forming a London-Specific Green Development Strategy. The City is also committed to advancing, where appropriate, new forms of development that promote alternative transportation and accommodate a mix of uses through appropriate intensification. The approach taken with the L-IEMS was to aid London in connecting built-form and transportation with energy use and to evaluate the potential impact of energy efficiency and GHG reduction strategies across the community. The information in the L-IEMS provides a starting point for the development of an action plan for energy efficiency in London.

1.2. CUI'S INTEGRATED ENERGY MAPPING APPROACH

The IEMOC initiative is based on the application of the CUI's integrated energy mapping approach, which was developed in collaboration with the City of Calgary and the Government of Alberta. Integrated energy mapping can provide municipalities, local electricity and gas distribution companies (LDCs) and government agencies with a common platform to convey complex energy concepts and present findings from data analysis in a compelling and visual manner using Geographic Information Systems (GIS).

This approach can aid communities and utilities to:

1. Identify the energy and GHG emissions associated with the built environment and with transportation by working with data from local utilities and other sources. Referred to as: energy mapping baseline.
2. Evaluate the potential for energy and GHG reductions through the

development of energy efficiency strategies and scenarios and by applying a cost-effective evaluation process. Referred to as: energy mapping assessment.

3. Implement the preferred energy efficiency strategies by identifying enabling policies, program tools and supportive actions. Referred to as: energy mapping implementation.

A municipality, LDC, government agency, community organization or private corporation can apply the entire process or any one of the steps which are outlined in Figure 1.

Understanding where energy is used in a community and where energy supply opportunities exist can contribute to making effective energy efficiency decisions. Integrated energy mapping assembles a wide range of data inputs that are used to develop a spatially distributed baseline for energy consumption in a community and evaluate the long-term effectiveness of energy reduction strategies.

An important component of the process is the financial assessment and cost sensitivity testing. Key financial indicators that were applied for the initiative include: internal rate of return (IRR) and cost per tonne ($/tonne) of GHGs reduced.[7] These financial indicators allow for identified energy strategies to be ranked against one another when being applied to achieve a desired target for energy, GHGs reductions, energy cost, or other objective.

The integrated energy mapping process also allows communities to evaluate various types of energy goals or scenarios. For instance, scenario building can be undertaken for the evaluation of different energy efficiency strategies that are compared and ranked against criteria relevant to a community.

The scenarios allow municipal, utility, and other key community stakeholders to assess a wide range of combinations of pricing, technologies, land-use and transportation efficiencies and building improvements from a numerical and visual (mapping) standpoint.

Accuracy and Limitations of Integrated Energy Mapping for the IEMOC Initiative

Assumptions and the methodology for interpreting data are documented in Appendix A. Models are subject to the accuracy and completeness of third party data. Where possible, actual metered energy use information was used. Simulations were used to supplement energy data for buildings and transportation and were integrated with metered data as described in Appendix A.

The priority of the IEMOC research was to explore the broader community energy and GHG emission reduction opportunities with a consistent methodology and approach, rather than to review in detail any one technology or strategy. As well, the approach to evaluate strategies for reducing energy and GHG emissions are based on “hard” policies, such as the changing of building design and technology or the use of alternative fuels for vehicles. Soft applications that are directed at behaviour change, such as building labelling, the application of incentives, and other approaches were not applied as part of the IEMOC initiative and are not evaluated as part of the L-IEMS.

[7] See separate Appendix document that provides an overview of the economics of capital project decision making applied for the IEMOC initiative.

Information on capital and operational costs for TDM, technology improvements, and fuels are beyond the scope of the IEMOC initiative and are not evaluated as part of the L-IEMS.

1.3. Applying the Integrated Energy Mapping Approach in London

For the City of London, all steps identified in Figure 1 below were undertaken. The starting point for the L-IEMS was the organization of an energy mapping workshop that outlined the use of energy in London and the associated GHG emissions. As part of the workshop, the concepts of energy mapping were reviewed, energy assets in London were identified, and key areas of further investigation were identified by stakeholders. At the workshop, participants were asked to identify energy efficiency opportunities by considering land-use and age of buildings, and to identify opportunities to improve transportation infrastructure in order to reduce energy demand. A summary record of workshop is available on the IEMOC project website at www.canurb.org/energymapping.

Selecting a Land-Use and Transportation Growth Scenario for Integrated Energy Mapping

A central component of the L-IEMS involves determining the future energy demand associated with projected population and employment growth out to a specified year. For the purposes of the IEMOC project, the Ontario Growth Plan time period of 2031 was examined in all participating communities.

An evaluation of where the new building space would most likely occur was undertaken and all future land-use development was distributed across the City in each transportation zone by City staff. For the L-IEMS, only one land-use development scenario was evaluated and was based on a Growth Scenario established by City staff of 1% population growth with 20% infill within the current Official Plan.

A detailed description of how population and employment projections were converted into floor space and distributed throughout the city is included in Appendix A.

For the L-IEMS, transit, cycle, and walking trips were determined using data from the 2010 Household Travel Survey which was undertaken to support the Smart Moves 2030 Transportation Master Plan for the City of London. The Household Travel Survey included a sample of approximately 5% of the residents of the City of London and 2% of the population of the remaining communities within the London Census Metropolitan Area (CMA).[8] The City of London retained AECOM to develop a multi-modal travel demand model as part of the London 2030 TMP (Smart Moves). AECOM provided to the IEMOC team peak hour AM transit and personal vehicle trip tables used for this modeling. Average trip lengths are based on Manhattan (rectilinear) distances and represent 24 hour average lengths. Outbound trips made from within the London City boundary were assumed to be made by residents.

The distribution of future population and employment among the City's traffic zones was developed by AECOM in consultation with the City for the transportation model development.

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[8] AECOM, *Working Paper: Household Travel Survey*, http://www.library.csi.cuny.edu/dept/history/lavender/footnote.html (November 2010).

Overall, London is experiencing slow but steady growth. Between 2008 and 2031 the population is expect to increase from 359,000 to 429,000 and the number of jobs is expected to increase from 201,000 to 230,000, which is consistent with the Official Plan's 1% Growth Scenario.

The City's Growth Management Implementation Strategy (GMIS) has provided an analysis of where that new growth will most likely occur, with 29,300 new residential units allocated to the urban fringe in new greenfield development, and approximately 23%, to be located within the existing built area.[9]

How Is Energy Measured and Reported in the L-IEMS?

The following metrics are used to discuss energy consumption:

- Natural gas is measured using cubic metres (m^3).
- Electricity is measured using kilowatt hours (kWh).
- Energy (gasoline and diesel fuel) used in automobiles and for transit is measured using litres (L).
- The embedded energy in food that we consumed is measured in calories (cal).

In terms of *demand*, the rate at which energy is generated or consumed is measured in Watts (100 Watt light bulb). Given the amount of energy being evaluated for a community, the unit of megawatt (MW), a unit of power equal to one million watts or 10,000 x 100 watt light bulbs, is used.

With regards to *consumption*, the amount of energy generated or consumed is measured in watt-hours (a 100 Watt light bulb operating for 10 hours is a kilowatt-hour (kWh).

For the L-IEMS, electricity, natural gas and fuel consumption for automobile use was all converted into a common metric of a joule. Because of the amount of energy being reported, the measure of gigajoule (GJ) is the preferred metric used to report energy. One GJ is equal to one billion joules.

A GJ is the amount of energy that can result from either: 278 kWh of electricity, or 26m^3 of natural gas, or 26 L of heating oil. It is also equivalent to the amount of energy consumed when: burning a million wooden matches, or cooking over 2500 hamburgers, or keeping a 60-watt bulb continuously lit for six months.

To put energy use in context, the province of Ontario electricity consumption is 2.4 billion GJ per yr for personal vehicles and public transit (excluding freight transportation). A small wind turbine in Ontario can produce 24,500 GJ per yr.[10]The average energy use per person in London is currently 110 GJ per yr.[11]

London Planning Districts

Figure 1-2 is a map of London's Planning Districts. Throughout the L-IEMS, reference is made to the specific Planning Districts to aid the reader with where energy consumption, investment, or efficiencies might be achieved.

[9]City of London, Smart Moves Fact Sheet: London's Growth, http://www.london.ca/Transportation_Planning/pdfs/SmartMovesFact_LondonGrowth_FINAL.pdf.
Accessed July 2011.

[10]Assumes 10kW and 28% capacity factor as per Ontario monthly averagehttp://www.ieso.ca/imoweb/pubs/marketreports/WP_2007619-CanWEA-WindIntegration.pdf

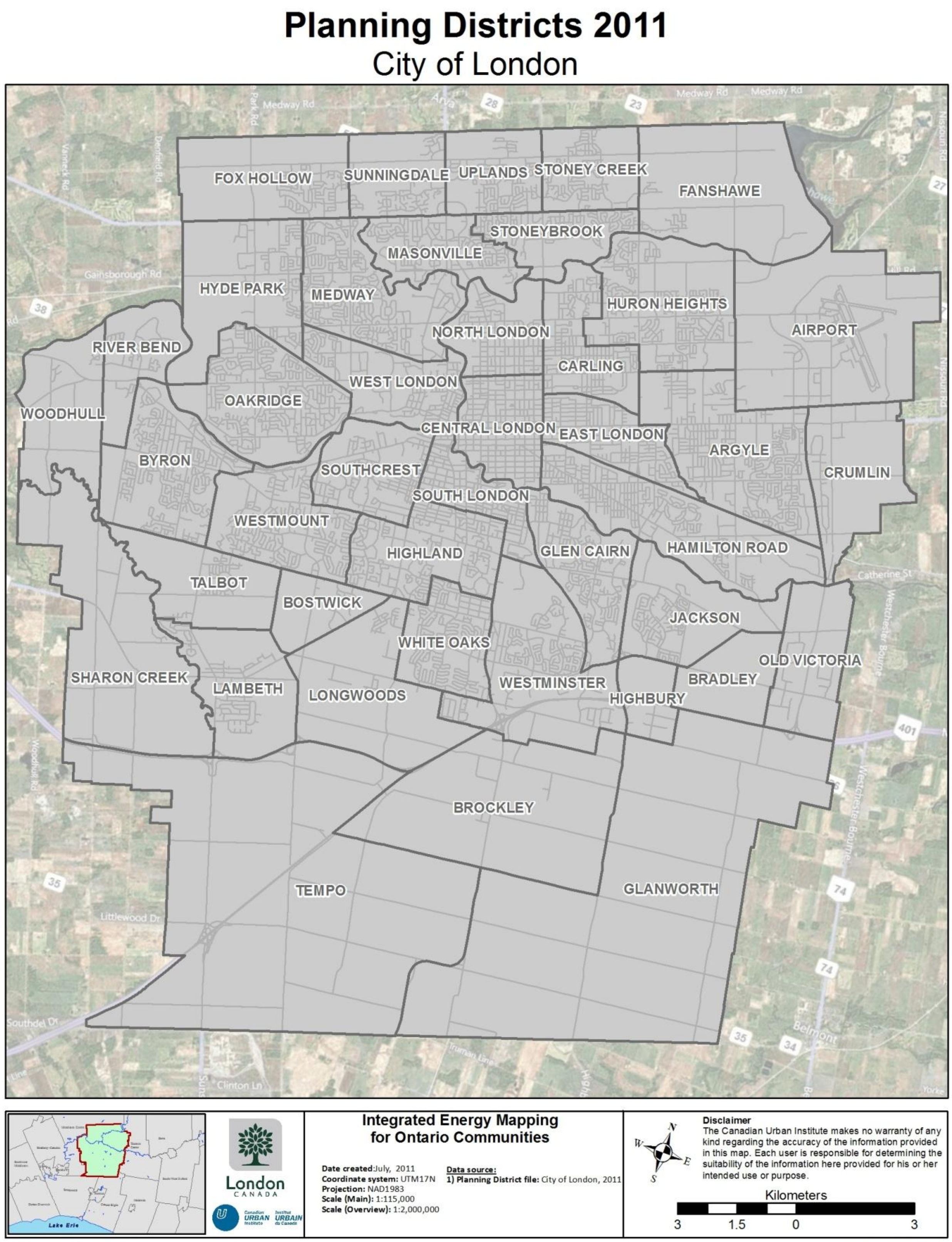
[11]Source: City of London IEMS Model.

TABLE 1-2 INTEGRATED ENERGY MAPPING PROCESS FOR LONDON

<table>
<tr><th colspan="6">Integrated Energy Mapping</th></tr>
<tr><td>step 1:confirm vision and energy sources</td><td colspan="5">Verified Community Energy Vision
• Identified key attributes of desired energy future.
• Identified sources of energy production and resources (including alternative technologies and renewable fuels).</td></tr>
<tr><td>step 2:collect baseline information (energy, land-use and transportation)</td><td>Baseline Building & Energy Sources
• Mapped all buildings in a community at the parcel level.</td><td colspan="2">Baseline Transportation
• Evaluated transportation zones using trip tables.</td><td colspan="2">Collect Energy Data
• Identified and quantified existing sources of data so that energy use could be identified at a building level.</td></tr>
<tr><td>step 3:prepare energy baseline</td><td colspan="5">Prepared Energy Coefficients
• Energy intensity factors for different fuel sources and uses [tonnes CO_2e/GJ] quantified</td></tr>
<tr><td>step 4:assess future growth projections (people, jobs, transportation land and building types)</td><td colspan="2">Compiled Future Building Data
• Conducted an analysis of the predicted future building stock.
• Energy use of future building stock identified in GJ/m^2</td><td colspan="3">Modelled Future Transportation Needs
• Future energy use and emissions estimated based on trip tables developed to model future transportation needs.</td></tr>
<tr><td>step 5:evaluate energy fuel & technology options</td><td colspan="5">Relevant Renewable and Alternative Energy Technologies Evaluated
• Micro FIT and FIT technologies: - wind energy, photovoltaics, biomass and non-FIT technologies: earth energy (Geoexchange), solar air, solar hot water and district heating.
• Intensity factors prepared for environmental impact [$/tonne CO_2ereduced] and cost [$/GJ] determined.
• Transportation options also identified in terms of trip reduction options (increase use of bus, cycling walking or different land-use patterns) and/or conversion to alternative modes of transportation (electric/hybrid vehicles).</td></tr>
<tr><td>step 6:incorporate financial analysis</td><td colspan="2">Operating Energy Cost Analysis
• Financial impacts of proposed scenarios developed and compared with the conventional scenario of BAU.
• Energy price forecasts and inflation forecasts taken into consideration.</td><td colspan="3">Avoided Energy Infrastructure Costs
• Assessed value of deferred electrical/gas infrastructure opportunities.
• Assessed costs and savings with improvements through relying on alternative technologies and renewable fuels vs. fossil fuel sources.</td></tr>
<tr><td>step 7:build scenarios (energy and conservation option/ policies)</td><td>Existing
• Prepared baseline map.</td><td>Future Business as Usual (BAU)
• Prepared Future BAU map.
• See information at GJ/m^2& GJ/ ha</td><td>Standard High Efficiency
• Prepared map.
• See information at GJ/m^2& GJ/ ha</td><td>Ultra High Efficiency
• Prepared map.
• See information at GJ/m^2& GJ/ ha</td><td>Other scenarios
• Prepared map.
• See information at GJ/m^2& GJ/ ha</td></tr>
<tr><td>step 8:evaluate</td><td>• Reviewed various scenario combinations of energy improvements.</td><td colspan="2">• Consulted with utility and city representatives to evaluate options.</td><td colspan="2">• Evaluate actions that can contribute to advancing preferred scenario(s) and informing actions for implementation.</td></tr>
</table>

Note: For a detailed overview of the Integrated Energy Mapping process, see Appendix A.

FIGURE 1-1 LONDON PLANNING DISTRICTS



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Date: 16/09/2011

2. Energy use and production in the province of Ontario and in London

Ontario is a recognized leader in the advancement of clean burning fuels and technologies with the enactment of the Green Energy and Green Economy Act (GEEA). These investments envisaged by the Act are redefining how energy is supplied and delivered across the province and how municipalities receive and produce power. This chapter reviews the supply and use of energy in the province of Ontario and in London.

2.1. Energy supply in the province of Ontario and in London

Ontario draws from a wide range of energy resources that include electricity (hydro, coal, natural gas, wind, nuclear, and other), natural gas and oil, as well as interconnections to jurisdictions in the United States and other provinces.

Ontario Electricity and Natural Gas Sources

In Ontario, energy consumption is expected to grow by 30% with the addition of 3.7 million people over the next 15 years.[12]

The current installed generating capacity of the province is over 31,000 MW. Nuclear facilities provide about 52% of Ontario's electricity, while coal provides 18% and hydroelectric provides 21%. Most of these facilities accommodate Ontario's baseload (about 13,000 MW).[13] Interconnections outside of Ontario provide an additional 4,000 MW. Historically, an equal amount of electricity was consumed by each of the residential, industrial, and commercial uses. Increasingly, the commercial/institutional sector is becoming the dominate sector of electricity use.[14]

While Ontario has some natural gas reserves, the majority of the supply is imported from Saskatchewan, Alberta, and British Columbia.[15] Natural gas in Ontario is used for a wide variety of uses from industrial processing to heating homes to fuel for transportation. Electricity is also produced from natural gas and accounts for nearly 6% of Ontario's generated capacity. Natural gas is the primary fuel source used in Ontario to address peak demand for electricity.[16]

Local Generation in London

The building fuel types evaluated for London include electricity from the Ontario grid and natural gas. Data was received from Union Gas, London Hydro and London District Energy for 2008.

While London draws extensively on the use of electricity from the grid and natural gas, the City also has a number of local energy generators within the City including Canada's oldest district heating system. The London District Energy system now generates electricity and provides heating and cooling to commercial and institutional buildings in downtown London, St. Joseph's Hospital to the North, and South Street Hospital to the South. London Health Sciences Centre's Victoria Hospital campus has a cogeneration plant that generates electricity and provides heating to the

[12] Province of Ontario. Ontario's Long-Term Energy Plan. 2011

[13] Baseloadrefers to constant or unvarying demand for electricity.

[14] Rethinking Energy Conservation in Ontario: Annual Energy Conservation Progress Report – 2009 (Volume One)

[15] Ministry of Energy. Natural Gas. http://www.mei.gov.on.ca/en/energy/oilandgas/?page=natural-gas. Accessed December 15, 2010.

[16] Ibid.

hospital campus. Labatt Brewery and Casco also have cogeneration plants for generating electricity and process heat requirements,

London also has a number of installed and planned photovoltaic projects in the city. Table 2-1 summarizes the cogeneration and PV projects in London and Figure 2-1 illustrates their locations.

TABLE 2-1 EXISTING SOURCES OF LOCAL ENERGY GENERATION IN LONDON

Local Energy Initiative	Type of System	Capacity (MW)	Annual Energy Produced (GJ)
London Hydro's Medium-Voltage Distribution Network			
Veresen – London District Energy	gas turbine; combined heat & power	22.1	389,000 (steam) 28,000 (chilled water)[17]
Labatt Breweries	gas turbine; combined heat & power	5.25	Not reported
London Health Sciences	gas turbine; combined heat & power	6.4	447,000 (steam) 121,000 (electricity)[18]
Fanshawe Dam	hydroelectric	0.675	10,000[19]
Casco	gas turbine; combined heat & power	15.75	Not reported
Feed-In Tariff (FIT) Projects			
Feed-In Tariff (FIT) (>10 kW)	4 roof-mounted solar PV	1.02	Not reported
microFIT (<10 kW)	20 ground-mounted and 101 roof-mounted solar PV	0.98	Not reported

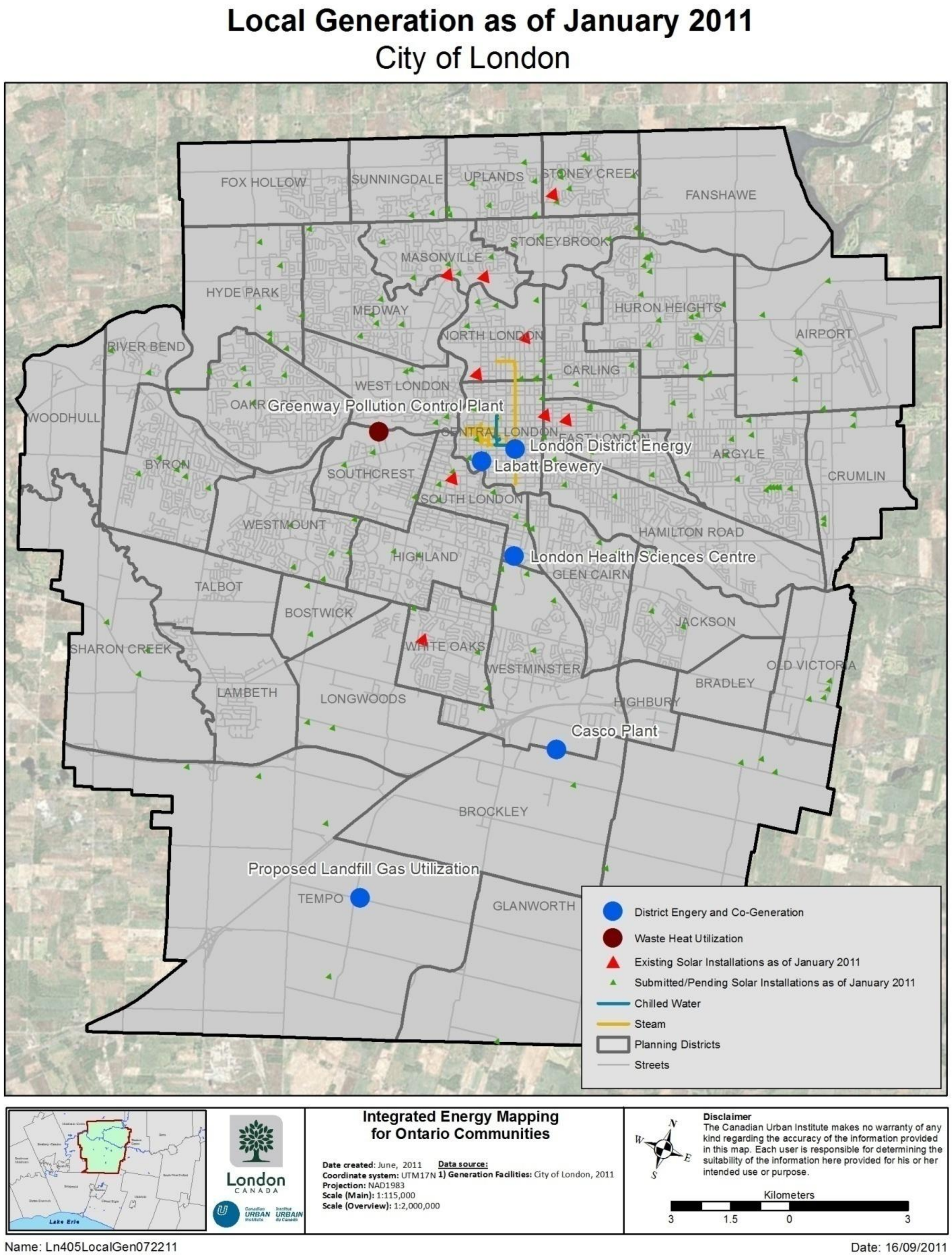
Source: System operators.

[17] London District Energy annual 2008 generation provided by LDE staff, November 2011.

[18] London Health Sciences annual 2008 generation provided by Canadian District Energy Association, July 2011.

[19] Fanshaw Dam output averaged over past 5 years provided by Upper Thames River Conservation Authority staff, August 2011.

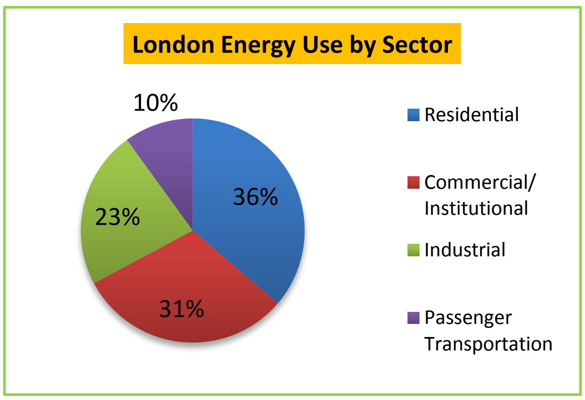
FIGURE 2-1 LOCAL GENERATION IN LONDON



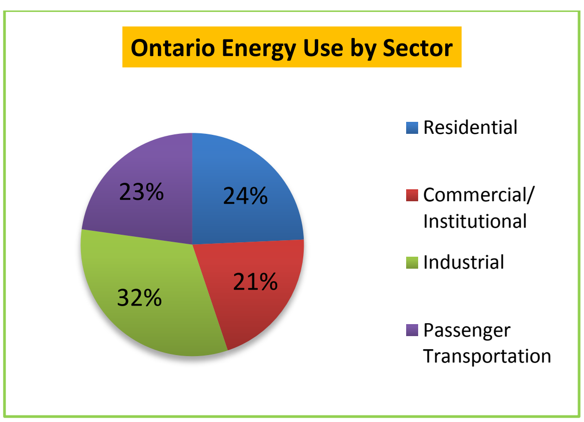
2.2. ENERGY USE IN THE PROVINCE OF ONTARIO AND IN LONDON

Figure 2-2 illustrates the breakdown of total energy use by sector in London and in Ontario. In London, a higher proportion of energy is consumed in the residential and commercial sectors compared to the provincial totals (36% and 31% respectively for London and 24% and 21% for Ontario). The industrial and transportation sectors consume less energy proportionally than the provincial total, constituting 23% and 10% of the City's energy use respectively compared to 32% and 23% for the province.

FIGURE 2-2 ONTARIO AND LONDON ENERGY USE BY SECTOR



Source: City of London IEMS Model



Source: Ontario Energy Use: Comprehensive Energy Use Database. NRCan

Here transportation energy use includes only estimated energy used for trips generated within London's municipal boundary by residents. The amount of energy associated with all trips captured by London's Household Travel Survey is discussed in Chapter 4.

City of London Electricity and Natural Gas Use

London uses approximately 11,700,000 GJ/yr of electricity and 24,000,000 GJ/yr of natural gas for buildings, and an additional 4,000,000 GJ for transportation as shown in Appendix 1, Table A-7. This represents about 1.9% of the total energy consumed in Ontario for commercial, office, residential, institutional, and industrial buildings and 1.7% of the total energy consumed including buildings and transportation. The total amount of energy is based on data received from London Hydro (electricity), and Union Gas (natural gas) for London residents. The total energy demand excludes other fuel uses, such as fuel oil, propane, biomass, etc.

Appendix 1, Table A-7 also provides an overview of London's total energy consumption for 2031 to meet expected population and employment demands. To accommodate the increase in population growth of 70,500 people by 2031, or a 1% annual growth rate, it is projected that an additional 20% (2,309,000 GJ/yr) of electricity and 14% of (3,484,000 GJ/yr) natural gas will be required to meet the energy demands of London assuming business as usual development practices. Increases in energy for transportation are also expected with an overall growth in energy for transportation of 14% (567,000GJ/yr).

In all circumstances, the average annual cost of energy is expected to increase as well. Currently, the total cost for all electricity and natural gas used in buildings and fuel for transportation in

London is estimated at $427 million per year. With the full build out for London to accommodate the expected population, employment, and transportation demands, it can be expected that the cost of supplying energy in London will increase by about 17% to $500 million per year assuming no increase in electricity, natural gas, gasoline, or diesel prices.

Without considering any escalation in fuel prices, it is anticipated that the average annual fuel cost per person will decrease slightly from $1,190 to $1,165 per person per year including transportation fuels due to improvements to the building code and practices and projected increased transit ridership, cycling and walking trips. Factoring in an escalation rate of 2% applied to commodity costs of electricity, increases in natural gas prices as projected by GLJ Petroleum Consultants for the Canadian Oil and Gas Industry as well as a 5% escalation rate for gasoline and diesel,[20] the anticipated annual energy cost per person in 2031 is projected to be $2,200 or an 85% increase. However, considering the transmission and distribution costs that are likely to be incurred from upgrading the aging energy transmission and distribution infrastructure in Ontario, these prices are likely to rise to a greater extent than indicated by the estimated cost increase of electricity alone.

Residential and commercial sectors use the most energy in London, consuming 14,380,000 GJ and 12,273,000GJ each year respectively for buildings. This equates to approximately 67% of total annual energy use.

The industrial sector uses the next largest amount of energy in London, consuming 9,044,000 GJ per year or 23% of the City's energy.

[20] Based on average annual fuel price increase over 2001 – 2011

Visualizing Energy on a Map

The L-IEMS introduces new measures for visualizing energy using GIS. Useful metrics that can be used to describe energy include:

(GJ/ha): In this study, gigajoule per hectare is referred to as *energy density* and describes energy use per area of land or property. This metric can be used in conjunction with population and employment densities to understand how much energy a given parcel of land will consume for different types of development and can highlight areas where alternative energy generation technologies, such as district energy, can be technically or financially viable.

(GJ/capita): Gigajoule per capita describes the amount of energy used per person. This metric can be used to understand how efficiently, in terms of energy, a neighbourhood is able to accommodate residents.

(GJ/m^2): Gigajoule per square meter is referred to as the building *Energy Intensity Factor (EIF)* and describes a building's energy use per unit of building floor space area. This factor is useful for comparing efficiencies of different building types and building practices. Energy intensity factors are a function of the energy efficiency of the building envelope, space heating and cooling systems, water heating system, electrical appliances, and occupant behaviour.

(CO_{2e}): Equivalent carbon dioxide describes how much GHGs are associated with the energy consumed by an activity.

All of the above metrics can be represented visually on a map to show the variation in energy use and emissions generated by buildings and transportation throughout a neighbourhood or city.

In addition to mapping existing energy, cities can benefit from mapping projected future energy use based on development projections in order to supportenergy conservation and supply infrastructure planning.

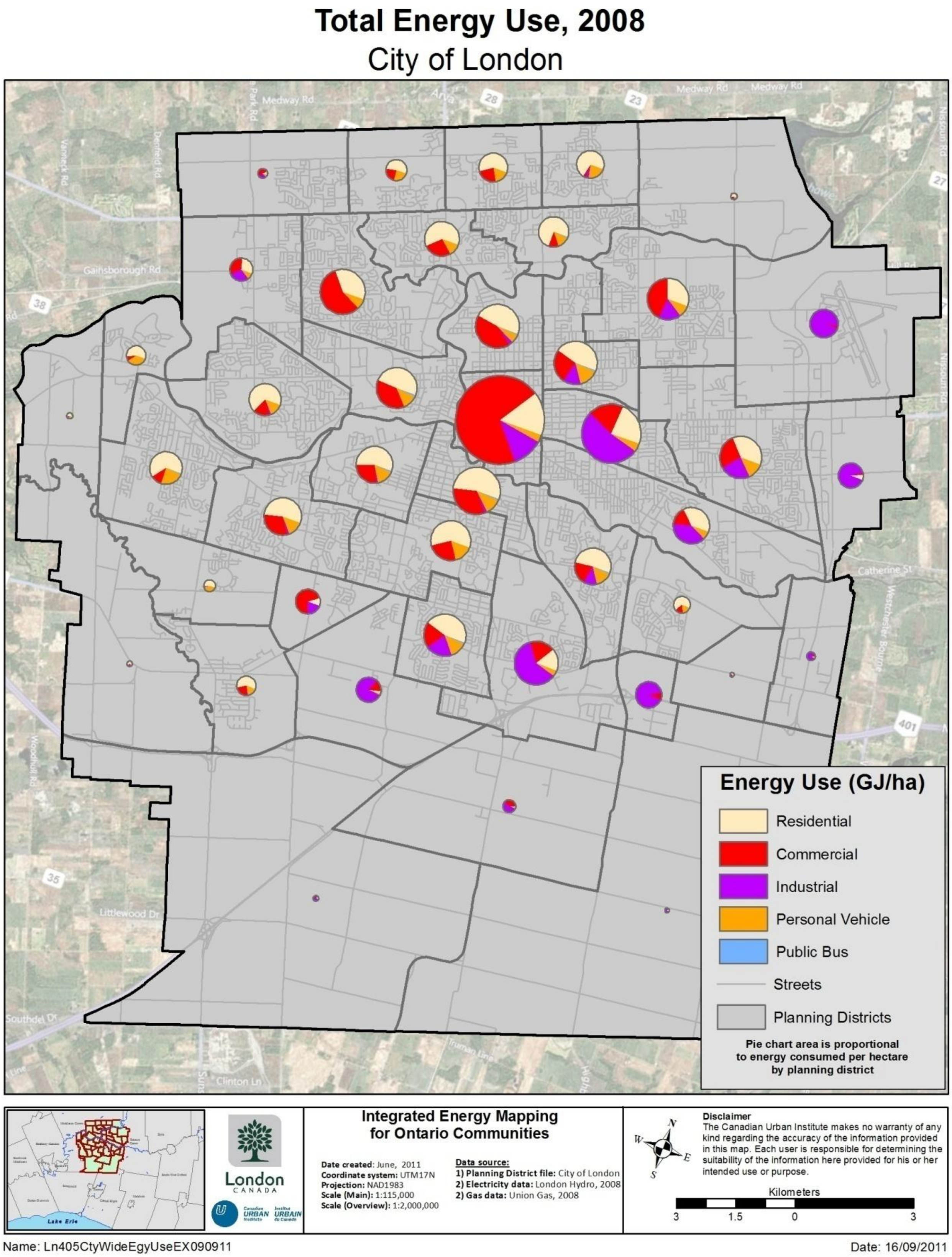
For the energy maps in the L-IEMS, energy data is represented at different levels of geography including the parcel or lot level, postal codes, Planning Districts, and transportation zones.

Different sectors and organizations will use different boundary systems to collect and manage data. Depending on corporate interest and privacy laws, data collectors will often aggregate data for public viewing. This can cause the modifiable areal unit problem (MAUP) which describes the challenges of integrating datasets that have been collected or aggregated using different boundary systems. The MAUP can also result in statistical bias depending on how boundaries are drawn.

Figure 2-4 illustrates the breakdown of annual energy consumption for buildings and transportation by Planning District in London. The size of the pie charts in the map is proportional to the total energy consumed within each of the identified Planning Districts. This means that larger pie charts represent more energy consumption.

Transportation energy includes energy used for automobile trips and transit trips and does not include trips passing through London or trips associated with goods movement or trips generated by non-residents. All energy consumption has been assigned to the residence of the trip maker, e.g. gas used by a London resident to travel from home to work, to the grocery store, and then back to home would all be assigned to the Planning District in which that resident resides.

FIGURE 2-3 LONDON TOTAL EXISTING ENERGY USE MAP



3. Building Energy Efficiency and Renewable Energy Evaluations

For the IEMOC, the starting point for analysis for each community has involved an assessment of energy efficiency that could be achieved through building improvements. This is followed by an assessment of the alternative technologies and renewable fuels that could contribute to meeting the heating, cooling and power needs for the built environment in London.

The chapter starts by providing an overview of the current energy demand in London and then reviews the potential impact of energy efficiency improvements in buildings and the type(s) of alternative technologies and renewable fuels evaluated. The section concludes with a review of three different scenario combinations of building energy improvements and alternative technologies and renewable fuels that were tested against a pre-selected set of criteria chosen for the IEMOC initiative.

3.1. Understanding Existing Building Energy Use in London

Nearly every organization that is in the business of collecting and managing data pertaining to buildings will have a different system for classifying buildings in accordance with their organizational goals.

As part of the L-IEMS, eight building types were established and building energy simulations were used to relate data collected by the Municipal Property Assessment Corporation (MPAC) and by the local utilities. This data was then used to develop a spatially distributed baseline for energy use in London. Table 3-1 provides an overview of the building type definitions used in the L-IEMS.

Figure 3-1 illustrates the total electricity and natural gas consumption by building type in London for 2008. From these figures it can be seen that London's single family and semi-detached homes consumed the largest amount of electricity and natural gas in 2008 (27% and 32% respectively). Industrial buildings (primarily unspecified standard industrial properties[21] and warehousing) also consumed a large amount of electricity and natural gas (21% and 27% respectively). Based on the data matching and modelling efforts, Figure 3-1 illustrates the 2008 baseline energy use breakdown by building type in London as defined in Table 3-1.

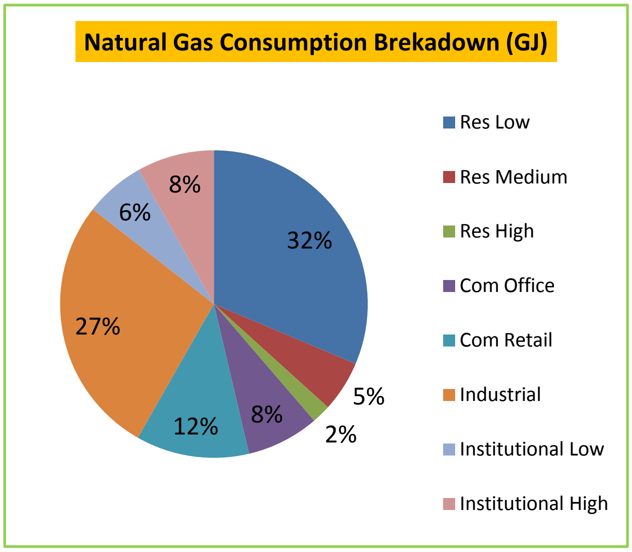
Table 3-1 Building Typologies Evaluated

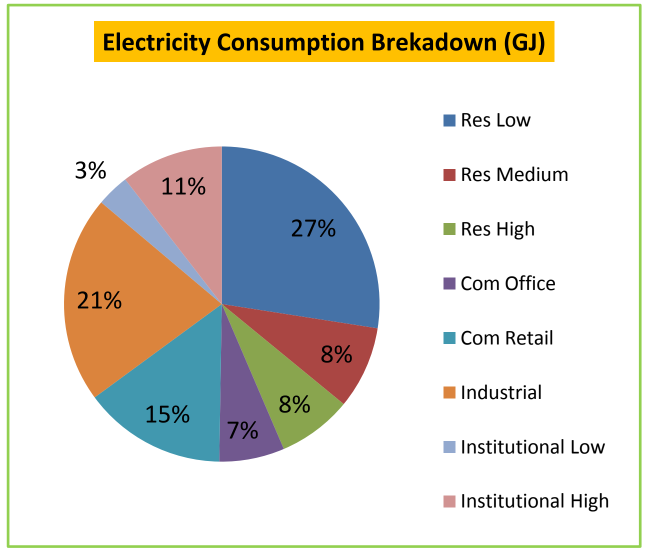
Building Typology	Definition	Total Existing Building Space (m^2)*
Residential Low	Single family homes	20,000,000
Residential Medium	Attached, duplex, row housing, walk-up apartments	5,400,000
Residential High	Apartments > 5 storeys	2,800,000
Commercial Office	Commercial office buildings	1,300,000
Commercial Retail	Commercial retail buildings	2,200,000
Low Intensity Institutional	Police stations, fire halls	1,000,000
High Intensity Institutional	Hospitals, college campuses, nursing homes	1,400,000
Industrial	Industrial buildings	4,600,000

Source: City of London IEMS Model.*Residential building space includes basements and common areas. For commercial and industrial buildings where building space has not been included in the tax assessment roll provided by the City of London, building space has been estimated using the building foot print (m^2) and an average number of stories.

[21] MPAC Property code 520: Standard industrial properties not specifically identified by other industrial Property Codes

FIGURE 3-1 LONDON EXISTING BUILDING ELECTRICITY AND NATURAL GAS USE





Source: City of London IEMS Model.

Comparing Residential Built Forms

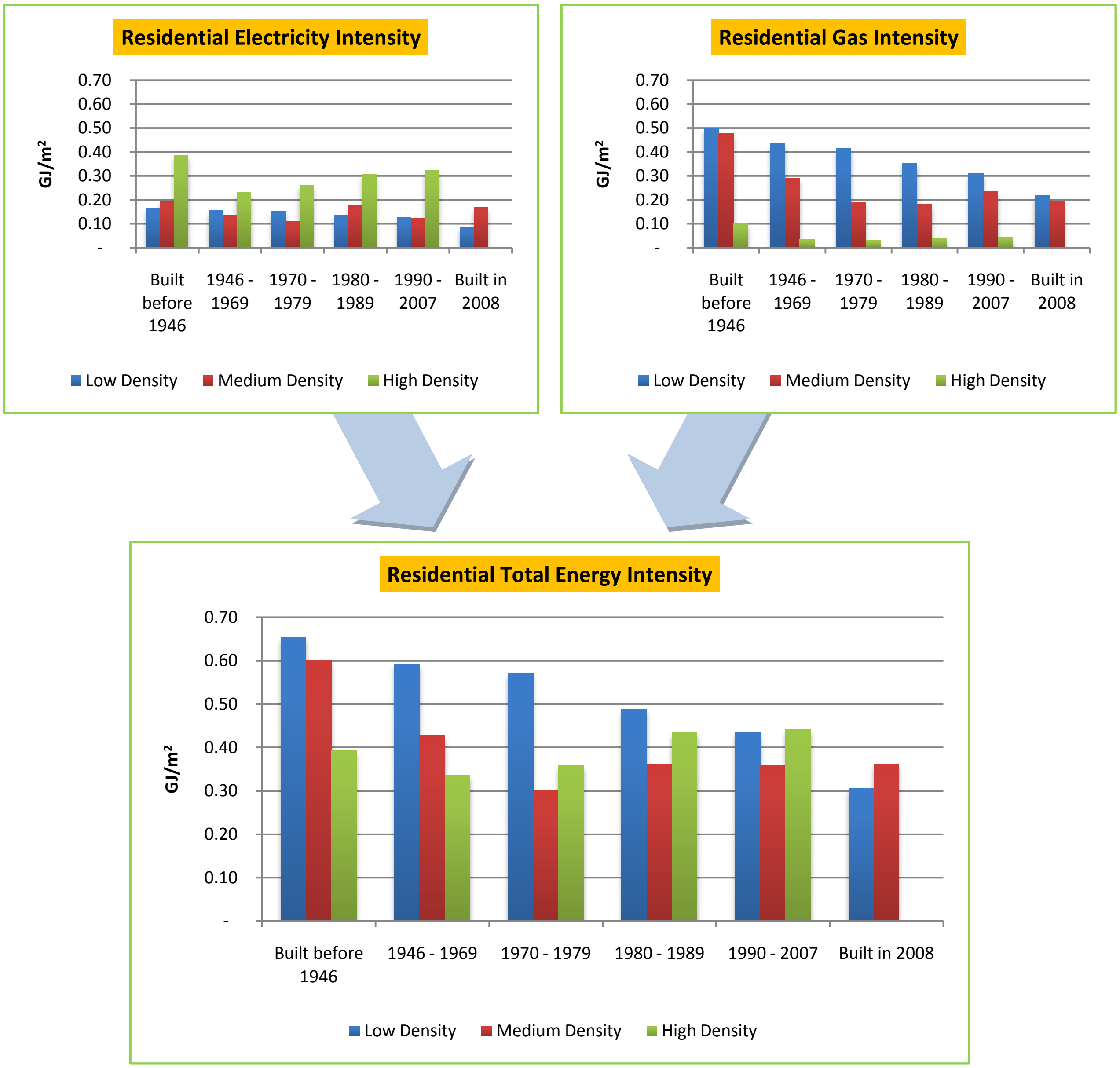
Within the residential building type classification, building energy use can vary based on building size, height, age, heating equipment, and other attributes. Because of the additional level of detail provided by local utilities and the City of London for the L-IEMS, we can now begin to explore the correlation between energy use in the residential sector and some of these variables.

It should be noted that consumption data provided by Union Gas has been provided in an aggregated format to protect customer privacy. For this reason it is not possible to verify the quality or accuracy of data received.

Figure 3-2 illustrates the variation in electricity and natural gas use (GJ/m^2) by residential building type broken down by age of building construction. Here it can be seen that energy intensity for low density residences (i.e., single family and semi detached homes) is decreasing in newer construction. It can also be seen that energy use in medium density (row housing) and high density (apartments) varies depending on the year built, with electricity use increasing in newer apartments.

Combining this information with energy mapping can help to identify neigbhourhoods to target for municipality or utility run energy efficiency programs.

FIGURE 3-2 COMPARING RESIDENTIAL BUILDING EFFICIENCIES



Mapping Residential Energy Efficiency

Within the low density building type, Figures 3-3 and 3-4 respectively illustrate natural gas and electricity hot spots. These maps indicate areas of high probability of above average natural gas and electricity intensity (GJ/m^2). In these maps, data has been run through a spatial analysis to identify concentrated areas of high and low energy intensity.

While it is difficult to evaluate opportunity for and cost effectiveness of home energy retrofits in these areas without additional information about the structure and values of residents, this metric can be used as a proxy for efficiency.

These maps are based on data received from Union Gas and London Hydro for 2008.

FIGURE 3-3 LONDON LOW-RISE RESIDENTIAL NATURAL GAS HOT SPOT MAP

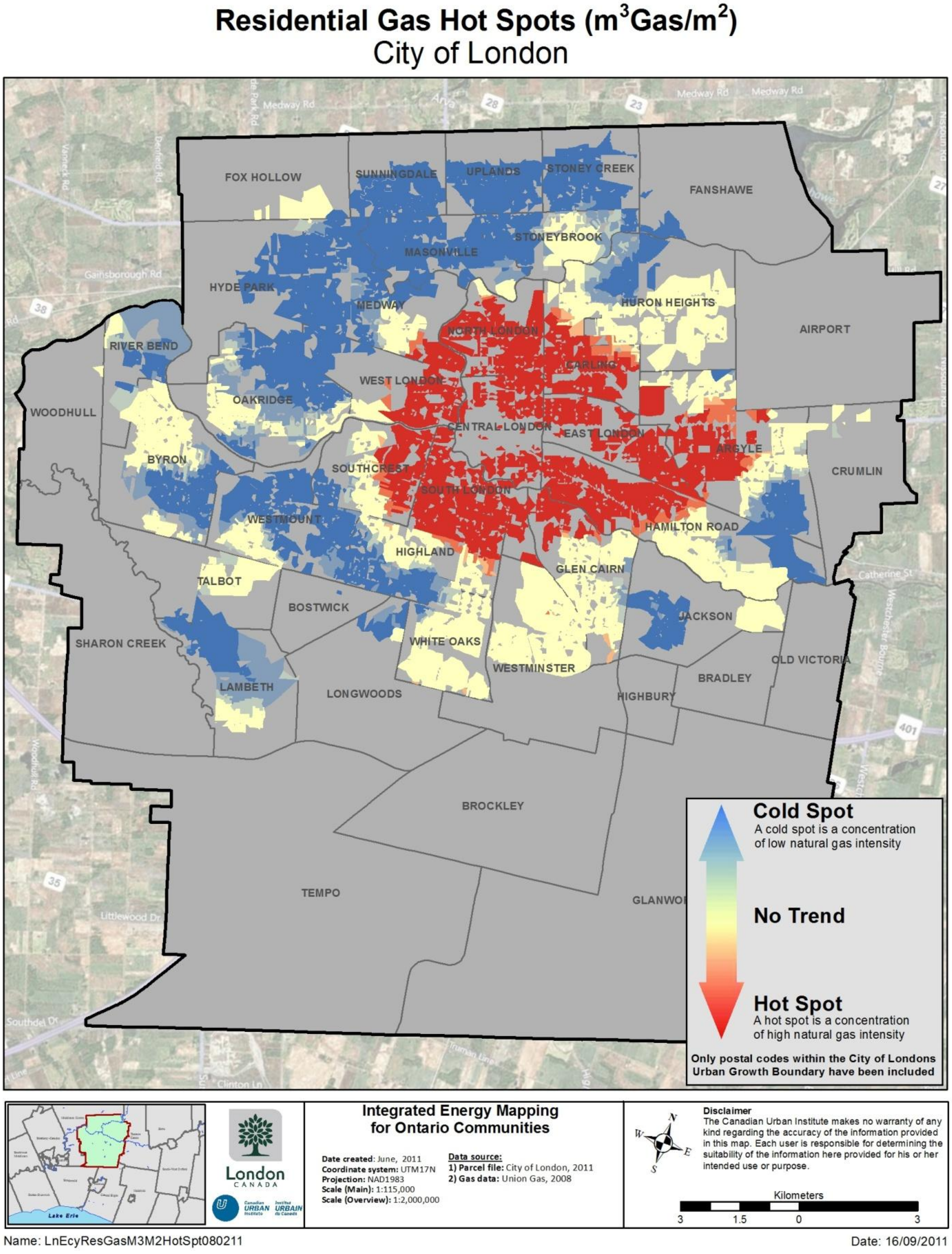


FIGURE 3-4 LONDON LOW-RISE RESIDENTIAL ELECTRICITY HOT SPOT MAP

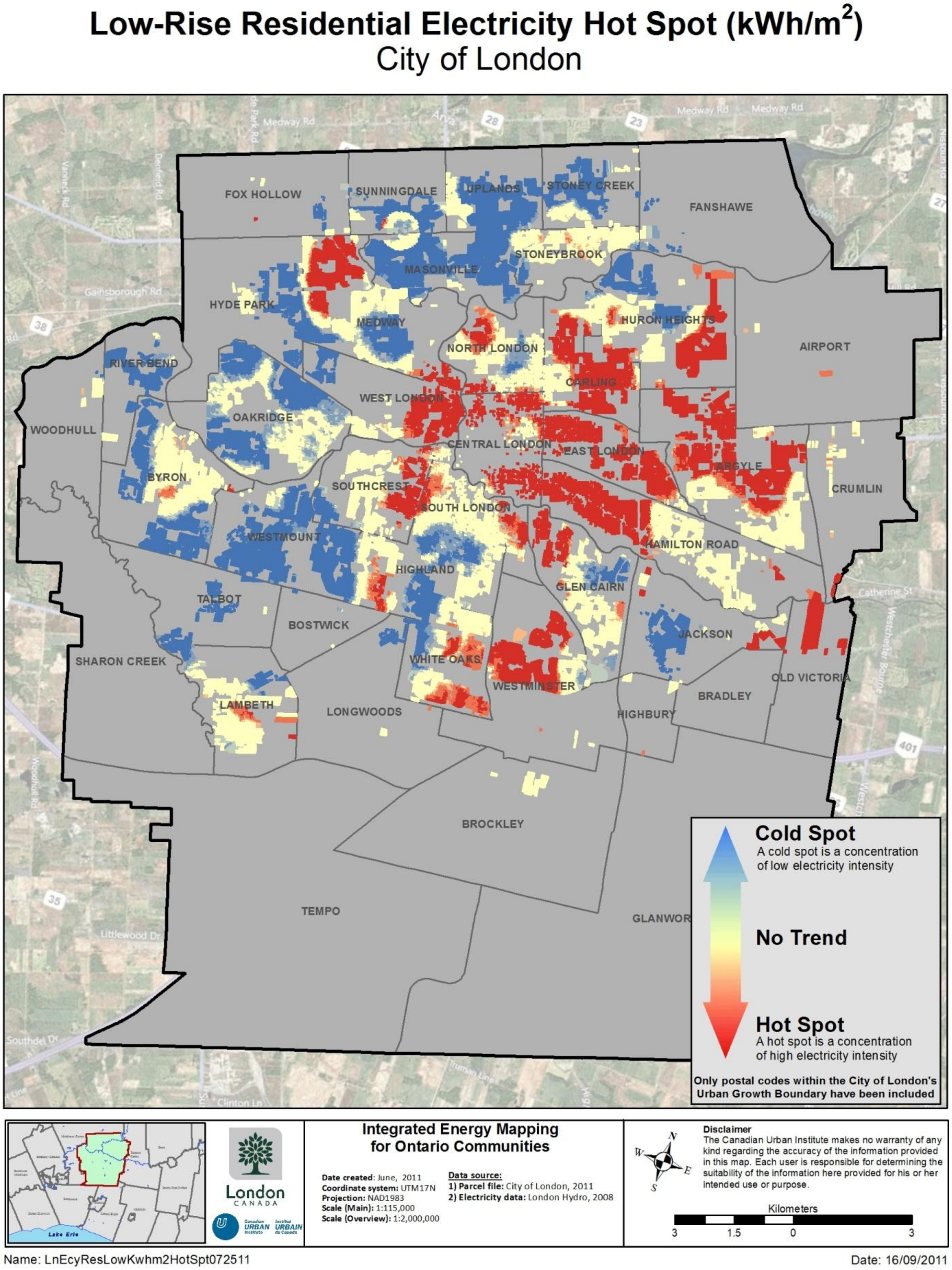
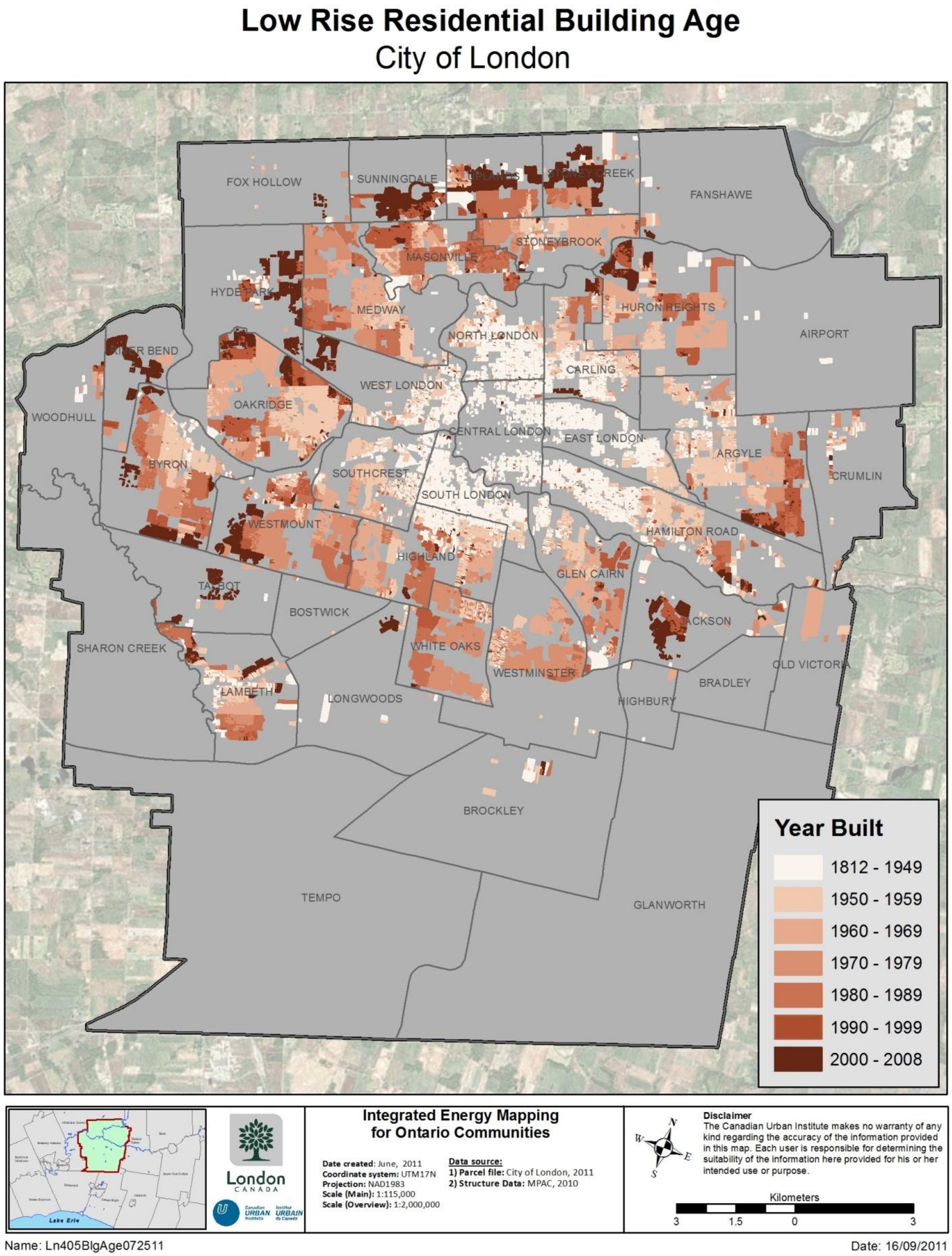


FIGURE 3-5 LONDON LOW-RISE RESIDENTIAL BUILDING AGE MAP



3.2. Evaluating Energy Efficiency Improvement Opportunities

For the purposes of the IEMOC initiative, the new Ontario Building Code (Ontario Regulation 350/06) was selected as the baseline for energy efficiency improvements.[22]

Table 3-2 provides a basic overview of the improvements to the Ontario Building Code (OBC) that were captured as part of the L-IEMS

Table 3-2 Ontario Building Code Improvements

OBC 2006 Scope of Improvements	Types of Changes
The Ontario Building Code (2006) balances energy efficiency with affordability and encourages innovation and flexibility within all building design and construction.	• In 2007, houses (under four stories) built will be 21% more energy efficient • By 2012, all new houses (under four stories) will be 35% more efficient and meet or exceed EnerGuide 80.[23] • By 2012, all new commercial buildings will be 25% more energy efficient than under MNECB standards.

Energy Improvement Cases Evaluated for London

To evaluate the potential costs and benefits of different efficiency improvements, the study reviewed three energy efficiency cases. Table 3-3 outlines the efficiency cases evaluated for new buildings and for the retrofit of existing buildings. For the IEMOC initiative, it was assumed that the higher building code standards are applied to all new buildings and energy efficient building retrofits are applied to all existing buildings.

For the purposes of this study, any 'major retrofit' of an existing building, including HVAC replacement, is considered new construction.

Table 3-3 Building Energy Efficiency Cases Evaluated

Cases	Improvement Levels Explored
Building Business As Usual (B-BAU)	
Existing Buildings	No retrofit
New Buildings	***All*** new buildings built to OBC 2012 (MNECB minus 25%)
Building High Efficiency (B-HE)	
Existing Buildings	Retrofit ***all*** existing buildings in London to consume 10% less energy than the business as usual Case
New Buildings	***All*** new buildings built to MNECB minus 50%
Building Ultra-High Efficiency (B-UHE)	
Existing Buildings	Retrofit ***all*** existing buildings to consume 25% less energy than the business as usual Case
New Buildings	***All*** new buildings built to maximum practical energy efficiency (MNECB 50-56%)

Source: IEMOC Study Standard Efficiency Cases

3.3. Building Efficiency Improvement Options to 2031

Table 3-4 provides an overview of the combination of building improvement cases and the potential reduction in energy and GHG emissions. This table illustrates that implementing Case III – B-UHE for both the existing and new construction building stock would result in a reduction of 12.1 million GJ/yr and would result in a 29% reduction in GHG emissions compared to the Business as Usual case.

A description of the energy efficiency improvement strategies for both new buildings and building retrofits is provided in Appendix A. Strategies ranged from the addition of insulation in the attic to installing a high efficiency gas furnace.

[22] In Canada, building construction is the responsibility of provinces and the territories. National direction on uniform standards and codes is provided by the National Research Council (NRC) and the Commission on Building and Fire Codes (CCBFC). Ontario has adopted Canada's National Building Code as its base code – the Ontario Building Code (OBC). Specific modifications have been made to address provincial priorities.

[23] Introduced by NRCan, an EnerGuide rating encourages consumers to purchase energy efficient equipment by providing them with information on the energy performance of competing products.

Figures 3-6 and 3-7 illustrate the distribution of projected annual energy consumption in the 2031 B-BAU case and B-UHE cases respectively. The maps illustrate energy consumption broken down by building type for each Planning District. The maps illustrate an overall reduction in the energy consumption in terms of gas and electricity demand for London of 29%.

TABLE 3-4 BUILDING ENERGY EFFICIENCY CASE OVERVIEW TO 2031

Building Scenarios		Annual Energy Use (GJ/yr)	Annual GHG Emissions (Tonne CO_2e/yr)	Additional Capital cost compared with BAU	Annual Energy Cost Savings ($CDN/yr)	Simple Payback Period (yr)
Existing + New (No retrofit of existing buildings, new buildings built to OBC 2012, electricity grid improvements)		41,491,000	1,646,000	$ -	$ -	-
Existing Buildings	Existing with no retrofit	35,697,000	1,433,000	$ -	$ -	-
	Existing -10%	33,120,000	1,405,000	$ 1,000,000,000	$ 46,000,000	22
	Existing -25%	25,514,000	982,000	$ 1,703,000,000	$ 77,000,000	22
New Construction (Projected Additional Energy Use)	New using OBC 2012	5,794,000	212,000	$ -	$ -	-
	MNECB/H -50%	4,156,000	129,000	$ 295,000,000	$ 9,000,000	32
	Ultra High Efficiency (UHE)	3,843,000	113,000	$ 398,000,000	$ 11,000,000	37
Building Combinations	Existing + B-HE -50%	39,853,000	1,925,000	$ 295,000,000	$ 9,000,000	32
	Existing + UHE	39,540,000	1,909,000	$ 398,000,000	$ 11,000,000	37
	Existing -10% + New OBC	38,914,000	1,617,000	$ 1,000,000,000	$ 46,000,000	22
	Existing -10% + B-HE	37,276,000	1,534,000	$ 1,296,000,000	$ 5,000,000	24
	Existing -10% + UHE	36,964,000	1,518,000	$ 1,339,000,000	$ 57,000,000	25
	Existing -25% + New OBC	31,308,000	1,194,000	$ 1,703,000,000	$ 77,000,000	22
	Existing -25% + B-HE -50%	29,670,000	1,111,000	$ 1,999,000,000	$ 86,000,000	23
	Existing -25% + B-UHE	29,357,000	1,095,000	$2,102,000,000	$88,000,000	24

Source: City of London IEMS Model. For a detailed overview of the methodology, see section on Building Modelling Science in Appendix A. The sum of the values for each category may differ from the total due to rounding.

FIGURE 3-6 LONDON BUILDING ENERGY USE 2031, BUSINESS AS USUAL MAP

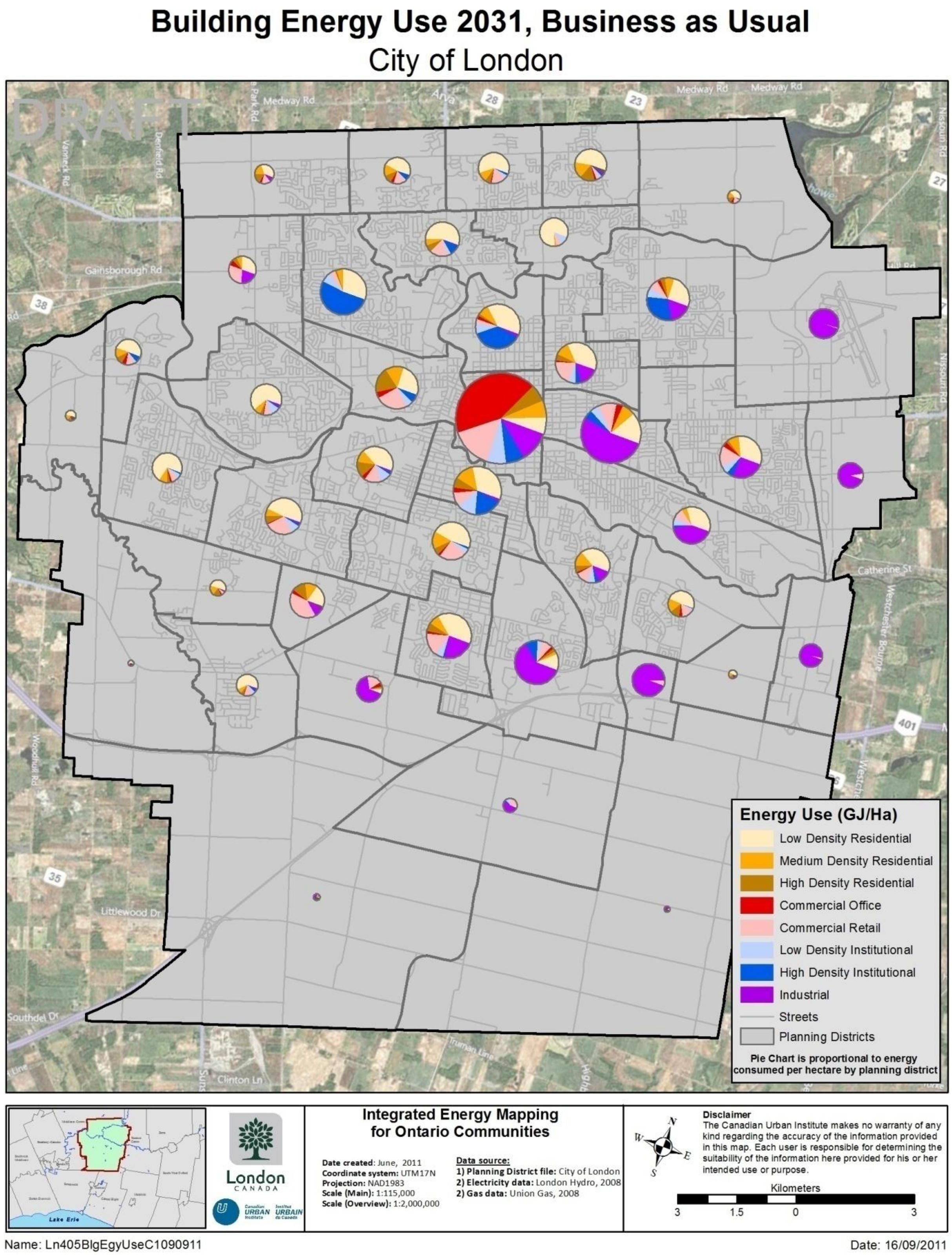
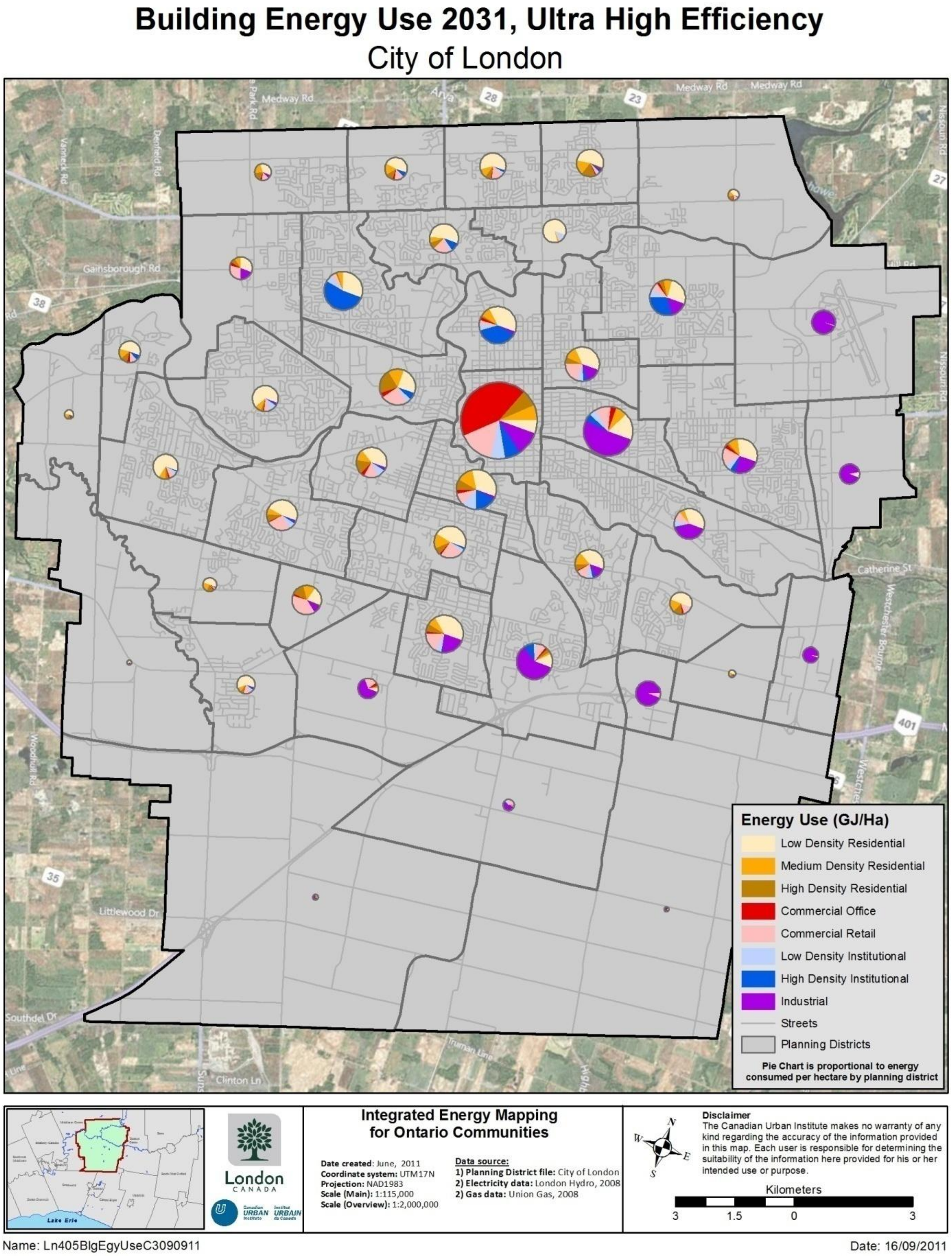


FIGURE 3-7 LONDON BUILDING ENERGY USE 2031, ULTRA HIGH EFFICIENCY MAP



Future Residential Buildings: Energy Per Capita

In addition to metrics of energy use per square meter for conditioned floor space and energy use per hectare of land area, *energy per capita* can be used to compare how efficiently energy is being consumed by the various residential building types.

Factors influencing energy use per capita include e*nergy intensity* which indicates how efficient a space is, using the metric GJ/m^2 as well as f*loor space per person* which shows how much floor space each building occupant occupies. Combining these metrics can reveal how much energy residents in a City consume using the metric e*nergy per capita*.

Figures 3-8, 3-9, and 3-10 illustrate energy intensity, floorspace per person, and energy per capita respectively for the building types low density residential (single family and semi-detached housing), residential medium density (primarily row housing), and residential high density (apartments) that will be built between now and 2031 assuming the business as usual case.

Based building energy simulations of incoming changes to the Ontario Building Code performed using NRCan's *Online Screening Tool for New Building Design* and energy use data provided by local utilities, it is anticipated that energy use in new apartments will be highest on average (per square meter). Note that this applies to new construction only (see Table 3-6). This is potentially due to energy required to heat and cool common areas, power pumps and fans and the challenges associated with insulating and sealing tall buildings.

Considering people per unit and unit sizes observed by London City planners in new housing development as illustrated in Figure 3-8 it is anticipated that mid-rise residential housing will be most energy efficient per capita in new construction as illustrated in Figure 3-10.

It is important to note that this analysis is based on aggregated data from local utilities and City planners and is meant to be a general overview of a few residential building types. A strong staff understanding of factors influencing building energy, coupled with a detailed energy database is needed to support planners in having a productive conversation with housing developers about energy.

FIGURE 3-8 LONDON RESIDENTIAL ENERGY INTENSITY

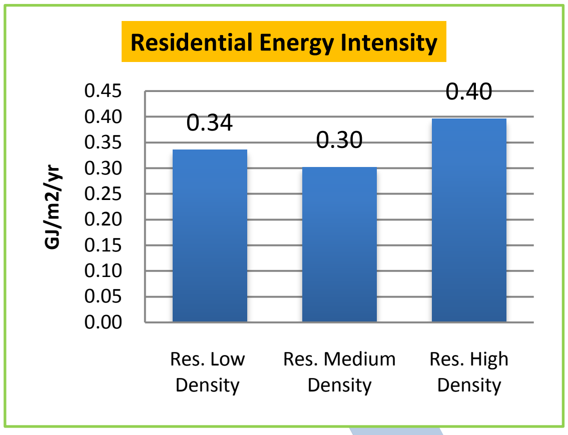


FIGURE 3-9 LONDON RESIDENTIAL AVERAGE FLOOR SPACE

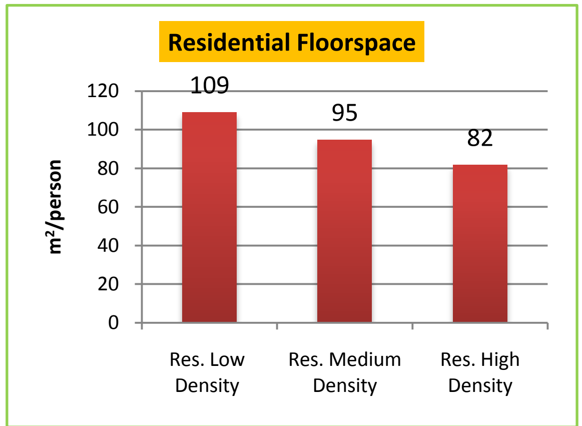
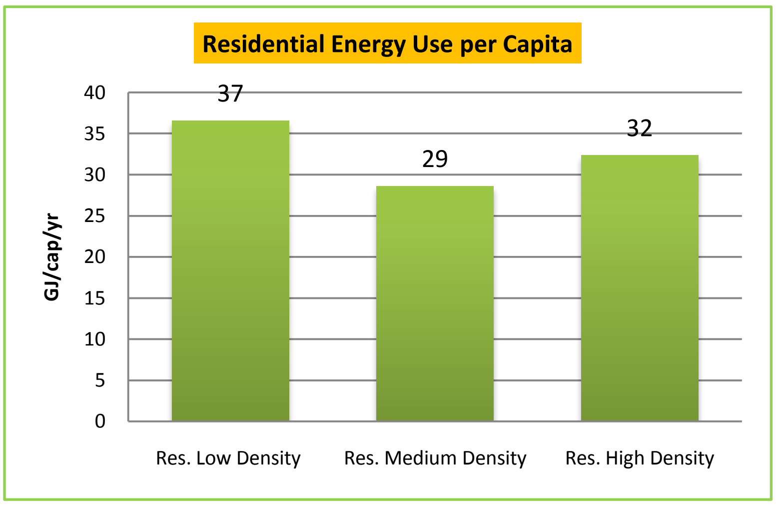


FIGURE 3-10 LONDON RESIDENTIAL ENERGY USE PER CAPITA



Evaluating the Financial Performance of Building Energy Efficiency Improvements

An assessment of the financial performance for each of the energy efficiency building improvements by building type was undertaken. The assessment involved evaluating B-UE and B-UHE against B-BAU. Building retrofit costs were calculated using Marshall Valuation Service cost data and should be considered average for all buildings within an evaluated building type across the City.

Economic feasibility for the IEMOC study is evaluated on the basis of the investment's Internal Rate of Return (IRR), which is the discount rate that makes the net present value of all cash flows for a particular project equal to zero. For energy utilities such as London Hydro and Union Gas, IRRs would need to be equal to or greater than the permitted Ontario Energy Board (OEB) regulated return. Similarly, private companies are likely to require an IRR higher than that of a regulated utility because of the higher risks or the need to provide a return to equity investors in their companies.

Generally speaking, the higher a project's IRR the more desirable it is to undertake the project. The discount rate for any individual firm will depend on the firm's weighted average cost of capital.

For a public agency or municipality, the discount rate is equal or close to the risk free long-term bond rate, although in some cases the provincial or federal government may specify a particular rate.

Given the historically low interest rates now occurring, a more conservative discount rate of 6% is recommended (conservative in the sense that a higher rate will put more weight on investment capital). Given the accuracy of cost and energy price forecasts, any project at least in the 4% to 8% IRR range should be considered worthy of further investigation, while projects with IRRs higher than 8% should be considered economically feasible.

For the purposes of the IEMOC study, the calculation of the IRR was determined based on a suite of efficiency improvements modelled using NRCan's *Screening Tool for New Building Design* for buildings and RETScreen for alternative technologies and renewable fuels. From the modelling, capital and operating costs were indentified. Individual IRRs were not prepared for each energy efficiency building technology option or alternative technology and renewable fuel. IRRs were prepared on the entire suite of efficiency improvements. It can be assumed that, in some cases, the IRRs for a particular building type or technology could perform better relative to the techniques, technologies and assumptions applied.

The investments can be grouped into three categories:

- Investments that are feasible: =>8%
- Investments that are probably feasible:
  4% - 8%
- Investments that are not feasible: =<4%

Figure 3-8 illustrates two types of returns for B-HE investments. Two B-HE investments are deemed feasible (they have an IRR greater than 8%):

- Office – New
- Institutional Low Density – New
- Industrial – New

The second set of B-HE investments are those with IRRs in the 4 to 8% range and require further analysis. These include:

- Retail – Retrofit
- Institutional High Density – New
- Industrial - Retrofit

The remaining building types under this approach do not appear economically feasible for city wide B-HE investments. However; using the additional data that has now been compiled as part of this study, the City of London can evaluate neighbourhoods where more cost effective retrofitting strategies have not yet been implemented. Figures 3-3 and 3-4 identify neighbourhoods for further analysis into such opportunities.

Figure 3-11 presents IRRs for B-HE and B-UHE investments. One investment is clearly economically feasible:

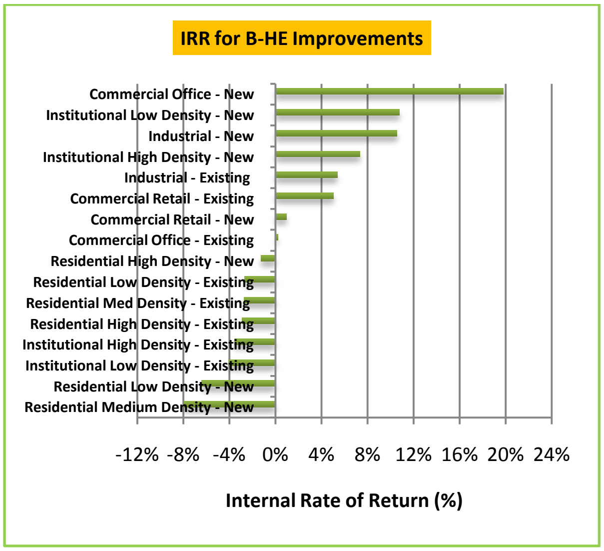
- Commercial Office - New

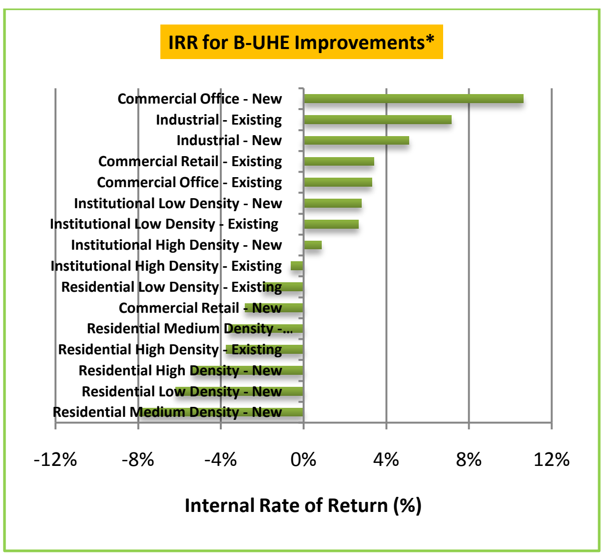
Two B-UHE investments in the 4 to 8% range of economic feasibility are:

- Industrial – Retrofit
- Industrial – New

The remaining building types do not appear economically feasible for B-UHE investments. Given that the BAU case evaluated as part of this study considered building efficiency standards required by the incoming 2012 Ontario Building Code, achieving higher efficiency will be challenging, potentially more so than opportunities available in new commercial construction.

FIGURE 3-11 IRR BUILDING ENERGY EFFICIENCY IMPROVEMENTS





*Note: Though not evaluated for London, retrofitting single family homes built prior to 1940's in the City of Hamilton to 10% better than existing performance on average resulted in an IRR of 12% based on building simulations. Targeting conservation demand management (CDM) and demand side management (DSM) programs to older homes in London could result in similar returns.

Source: City of London IEMS Model.

A cost sensitivity analysis of market prices for energy was performed that varied the price of electricity from the assumed 2% annual increase to 5% and then 10%.[24]

At a 5% annual electricity and price increase, six building type investment IRRs increased to the range of economic feasibility (i.e. IRR > 8%):

- Retail – Retrofit (High Efficiency)
- Institutional High Density – New (High Efficiency)
- Institutional – New (High Efficiency)
- Retail – Retrofit (Ultra High Efficiency)
- Office – Retrofit (Ultra High Efficiency)
- Institutional Low Density – Retrofit (Ultra High Efficiency).

At a 10% annual electricity price increase, one building type's investment IRR increases to the range of economic feasibility (i.e. IRR > 8%):

- Office – Retrofit (High Efficiency).

In practical, building-owner terms, one can also measure investment feasibility by calculating the payback period, which is a simple measure using undiscounted cash flows to determine the number of years it

[24]The Integrated Energy Mappingfor Ontario Communities approach relies on a specific natural gas price forecast (from GLJ Petroleum Consultants of Calgary) that gives specific natural gas prices for every year for the next 10 years (i.e., 2010-2019) and then assumes an average 2%/year price increase thereafter (i.e., 2020-2031). This leads to a natural gas price of $7.85/Gj in 2031. A sensitivity test on the effect of natural gas prices beyond 2031 was not undertaken because the discounting procedures used to calculate IRRs would render realistic price changes close to null. A correlation of natural gas price relates to oil prices was not performed since the two are traded differently (oil at world prices, natural gas at North American regulated prices) and so their prices do not follow the same $/Gj price trend.

would take to recoup the investment. Data from a recent Ontario Power Authority report "*Making Electricity Conservation & Demand Management a Priority for Business in Ontario,*" revealed that institutional building owners are seeking payback periods of no more than 3 to 6 years; commercial property owners/developers are seeking for payback periods of less than 5 years; and, industrial building owners are looking at payback periods of 1 to 2 years maximum.[25] A survey of local homeowner attitudes would be required to confirm the payback period that would be acceptable for this building type in London.

For the IEMOC initiative, it was identified that the acceptable payback period would be 7 years. This payback was identified as capturing residential building owners as well.

As shown in Figure 3-12, two B-HE investments meet this payback cut-off of 7 years:

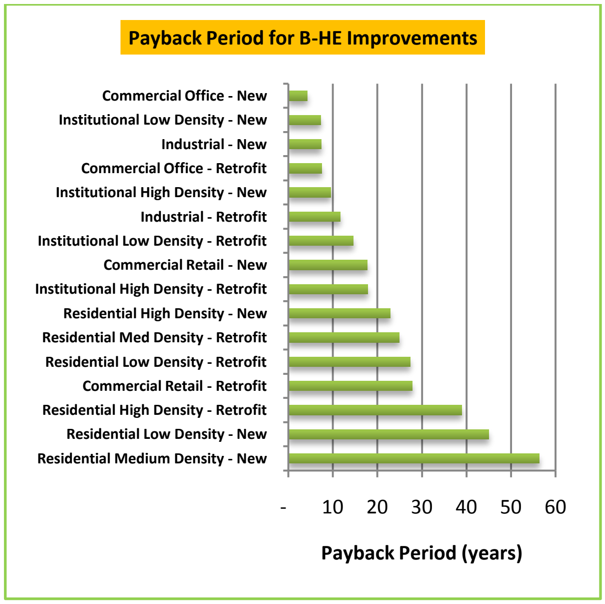
- Office – New
- Institutional Low Density – New.

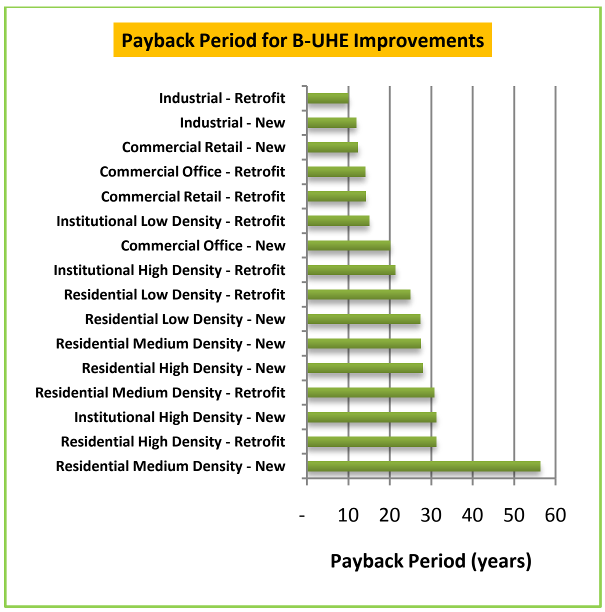
As shown in Figure 3-12, three B-UHE investments meet this 7 year cut-off period:

- Office – New
- Institutional Low Density – New
- Industrial – New.

The referenced IRR and selected payback period applied in the B-IEMS are conservative. At the same time, individuals, owners, employers, and the City might seek a different return for any particular strategy. An evaluation of potential market uptake was not performed. The preference for IRR or payback period should be considered when developing an action plan for energy efficiency in London.

FIGURE 3-12 PAYBACK PERIOD FOR BUILDING EFFICIENCY IMPROVEMENTS





Source: City of London IEMS Model.

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[25] Ontario Power Authority. 2008. *Making Electricity Conservation and Demand Management a Priority for Businesses in Ontario – Final Report*. The research methodology consisted of 30 in-depth telephone interviews with Influencers (Industry Associations, Architects, Consulting Engineers, Distributors, Government organisations) and Energy Decision Makers (28 Commercial, 22 Institutional, 50 Industrial), as well as 5 focus groups: 2 Commercial, 2 Industrial, 1 Institutional.

3.4. Evaluating alternative technologies and renewable fuels applicable to London

For the L-IEMS, alternative technologies and renewable fuels for electricity and thermal energy (space heating and domestic hot water) were pre-selected for evaluation. As part of the economic analysis, Feed in Tariff (FIT) rates offered by the OPA were applied. Ontario's Feed-in Tariff (FIT) Program is a guaranteed funding structure that combines stable, competitive prices and long-term contracts for energy generated using renewable resources. All the alternative technologies and renewable fuels evaluated for London were considered incremental to the expected grid improvements anticipated for Ontario.[26]

Table 3-5 provides the overview of the technologies evaluated for London. The following technologies ranked the highest for London with the application of micro-FIT and FIT pricing and included photovoltaics at the community and building scales, biomass electricity generation, and wind turbines at the community scale.

Factors considered when estimating the amount of natural gas or electricity that could potentially be displaced using renewable technologies include typical capacities of the systems and the physical limitations of the buildings to which they are being applied. For the case of wind generation it was also assumed that technologies could be owned by the municipality or its residents, but could be operated outside of the City boundary.

District Energy Considerations

For the L-IEMS, the financial feasibility of expanding the district energy system in downtown London was evaluated. This analysis calculated the internal rate of return for connecting all existing buildings in downtown London to a natural gas DE combined heat and power (CHP) system.[27] The analysis did not consider the value of stranded heating and cooling assets (i.e. boilers, chillers etc.) within existing buildings.

While the financial case can be made for connecting both existing buildings and projected new development to a DE CHP system, according to published plans to green the provincial electricity grid, using natural gas as a fuel source to generate electricity may result in increased emissions compared with a conventional system over the long term.[28] It should be noted that, consistent with the provincial direction to green the grid, proponents of district energy support transitioning away from reliance on natural gas as a feedstock for base loads on the basis that a district energy system can be adapted to accommodate renewable energy sources. Further, while natural gas does comprise only a small fraction of the projected contribution to the Ontario grid in long term provincial plans, natural gas is also being used as a transition fuel in the

[26] For the L-IEMS, it was assumed that FIT and micro-FIT projects would occur in London as part of "greening" the grid and expected overall supply improvements. It was also assumed that that FIT and micro-FIT subsidies would be available irrespective of the grid status. Assessments were divided between the micro-FIT program projects under 10 kilowatts and best suited to direct building applications and the FIT program, projects over 10 kilowatts and are of sufficient size and capacity to be evaluated at the community scale or larger.

[27] Combined heat and power (CHP) is one energy source for a district energy system and involves the production of thermal energy (hot water or steam) and electrical power using one type of fuel input. CHP technologies work to recover thermal energy that would be wasted in an electricity generator, and save the fuel that would have been used to produce thermal energy in a separate system. CHP is usually achieved by generating electrical power and having exhaust heat recovered from the process for heating water or producing heat to drive a turbine and generate electric power.

[28] For the purposes of this analysis, factors presented in OPA's 2010 District Energy Research Report have been used. Further review of the applicability of these factors to London could produce alternate results.

effort to phase out coal power generators. While not part of the scope of this study, further analysis into the best uses of natural gas as a transition fuel would be beneficial for community energy planning in London.

Incorporating alternative technologies and fuels into proposed district energy systems, such as solar hot water or biomass should be considered to ensure that the City's goals of ensuring stable energy prices for residents, while reducing total energy use and GHG emissions can be met simultaneously.

This analysis considered the total annual energy consumption breakdown for the 8 building types evaluated for the L-IEMS. Additional analysis considering current and projected peak demand as well as daily and annual load profiles should be undertaken as part of district energy pre-feasibility and feasibility studies for London.

Return for Alternative Technologies and Renewable Fuels

An economic assessment was also performed for alternative technologies and renewable fuels. This was done in the same manner as for buildings, on the basis of the investment's IRR.

As shown in Table 3-5, no alternative technology or renewable fuel investment at market prices for energy achieved an IRR greater than 8%. Biomass technology at market prices for energy is in the 4 to 8% range of feasibility and requires further analysis. The remaining alternative technologies and renewable fuel investments were not found to be economically feasible at market prices for energy under current assumptions and forecasts.

The following alternative technologies and renewable fuel investments achieved IRRs greater than 8% but only with OPA's FIT price incentives:

- Biomass (micro-FIT)
- Photovoltaic (microFIT)
- Wind (FIT)
- Photovoltaic (FIT)

No other FIT-applicable investments are feasible under current assumptions and forecasts.

TABLE 3-5 ALTERNATIVE TECHNOLOGIES AND RENEWABLE FUEL POTENTIAL

Technology	Energy Source Displaced	Total Potential Capital Cost	Rate of Return with FIT Pricing	Rate of Return without FIT Pricing	Maximum Potential Energy Displaced (GJ/yr)	Maximum Potential GHG Reduced Tonnes (CO_2e/yr)
Photovoltaic – FIT	Electricity	$3,963,000,000	8%	-6%	3,390,000	25,000
Photovoltaic – microFIT	Electricity	$3,963,000,000	18%	-6%	3,390,000	25,000
Biomass - FIT	Electricity	$493,000,000	19%	7%	2,825,000	21,000
Wind - FIT	Electricity	$387,000,000	11%	4%	565,000	4,000
Wind - microFIT	Electricity	$387,000,000	2%	-3%	565,000	4,000
Solar Air	Natural Gas	$743,000,000	N/A	-2%	4,431,000	249,000
District Energy – connecting existing buildings downtown	Natural Gas and Electricity	$98,000,000	N/A	4%	1,008,000	-29,000
Solar Hot Water - microFIT	Natural Gas	$6,845,000,000	N/A	-9%	17,725,000	994,000
GeoExchange - microFIT	Natural Gas	$3,682,000,000	N/A	No return projected. Electricity price exceeds cost of natural gas displaced	23,679,000	1,278,000

Source: City of London IEMS Model. For a detailed overview of the methodology, see section on Technology and Financial Assessment in Appendix A. The sum of the values for each category may differ from the total due to rounding.

3.5. BUILDING EFFICIENCY, TECHNOLOGY AND ALTERNATIVE FUEL SCENARIOS

As part of the assessment for London, three scenarios were evaluated that drew from a combination of energy efficiency strategies and were evaluated against a set of criteria selected for the IEMOC initiative. A detailed breakdown for each scenario regarding building improvements evaluated, technologies and fuels is available for review in the separate Appendix document.

Scenario One: Maximizing the application of cost effective building energy efficiency improvements and technologies with an internal rate of return (IRR) of at least 6%.

This scenario applied only cost effective building improvements and alternative technologies and renewable fuels that had an IRR of greater than 6%.

This Scenario includes retrofitting existing industrial buildings and higher efficiency construction of new office as well as small and large institutional buildings. This scenario also incorporates renewable technologies currently subsidized by the Feed-in-Tariff program.

As the City continues to build momentum and market transformation, these strategies can be prioritized in the short to medium term (2012 – 2025) as good for the environment and the economy.

Scenario Two: Maximizing GHG reduction using proven technologies with a cost of under $78/tonne of GHGs reduced.[29]

This scenario maximized lower cost building improvements, technologies, and fuels first and then progressively higher cost energy efficiency strategies based on a $/tonne of GHG reduced. The cut-off of $78/tonne of GHGs reduced was selected to compare strategies in an objective way and was relevant to international best practices reflecting anticipated vales of carbon reduction.

Strategies found to meet this criterion were the same as those identified in Scenario 1: Internal Rate of Return of at least 6%. This metric confirms the ability of these strategies to cost effectively contribute to the reduction of emissions in the City in the short term.

Building improvements and renewable technologies identified in Scenario Two can also be prioritized in the short to medium term (2012 – 2025).

Scenario Three: Maximizing the reduction in the consumption of fossil fuels

This scenario applies the B-UHE case and the use of alternative technologies, and renewable fuels to maximize the displacement of natural gas and electricity fuel inputs in London. The scenario was selected to demonstrate the potential to reduce reliance on fossil fuels.

Under Scenario Three, London could potentially move towards the concept of a carbon neutral city. The scenario outlines that maximizing building efficiency and applying all relevant technologies and fuels could significantly reduce the reliance of electricity from the grid and natural gas. For London, applying this scenario would involve a very high initial capital cost, while benefiting from long-term and cumulative energy cost savings. Achieving this scenario would require the development of a long-term energy vision for London that integrates energy efficiency into most decision making activities. This scenario should be evaluated over the long term from 2025 – 2050.

In order to achieve this scenario of being carbon neutral, every energy efficiency strategy identified would need to be implemented to the fullest extent possible. The starting place for the development of the scenario would involve an energy efficiency action plan that sets out a range of programs to advance building improvements and technologies identified. For instance, initiatives to expand the methane capture from London's landfill for the purpose of electricity generation and advancing waste heat capture from the water pollution control centre are examples of projects that could be replicated, where possible, across the city. Encouraging community energy systems, such as district energy supplied by alternative fuels (waste heat capture, methane, biomass etc.) would contribute to reducing reliance on natural gas.

Transportation improvements were not included in the building efficiency and technology scenario evaluations as transit, vehicle efficiency and TDM capital costs

[29] In keeping with international best-practices for the adoption and selection of proven technologies for reducing GHGs, the IEMOC team referenced the *Pathways to a Low Carbon Economy Version 2 of the Global Greehouse Abatement Curve* study that adopted a €60 per tCO_2e cut of measure for the ranking of technologies. Using IPCC terminology, the study evaluated the economic potential below €60 per tCO_2e for techncial emission reduction opportunities. The study selected an economic cut-off to compare the size of opportunities within different sectors and regions. Technologies under €60 per tC02e cut off measure were identified as proven, while those over €60 were considered to be early-stage technologies. The equivalent Canadian pricing applied for London was $78/tonne considering the Euro exchange rate at time of study.

were not evaluated as part of the IEMOC study. However, achieving maximum reduction of fossil fuels demand in London will certainly require transportation demand management and transition to renewable transportation fuels.

Evaluating Employment Potential for Ontario and London

As part of the evaluation process for assessing the benefits associated with undertaking the evaluated energy efficiency strategies and scenarios, potential employment gains were assessed. The evaluation of employment was limited to jobs that could be established in Ontario as sub-provincial models were not prepared as part of the IEMOC initiative.

The majority of local jobs that would be created from any of the energy efficiency strategies would be construction and maintenance related. Therefore, it can be assumed that over half of the expected jobs discussed below could fall to London for any one of the scenarios.

For London, job creation was measured by:

- disaggregating estimated capital expenditures over the life of a project (20 years) into specific industries;
- applying Statistics Canada employment multipliers for specific industries in Ontario to the estimated capital expenditures for each scenario.

The results in person-years of employment were then converted into net “full time jobs,” (defined as one job position, which may be occupied by different people, extending for a 25 year period). The term ‘net” is used to note that declining investment in business as usual practices will result in some job loss in the conventional energy production and transmission sectors.

The results of the analysis are as follows:

- Scenario 1: 3,400 net full-time jobs created in Ontario (9.5 person-years of employment per $1 million capital investment).
- Scenario 2: 3,400 net full-time jobs created in Ontario (9.5 person-years of employment per $1 million capital investment);
- Scenario 3: 6,200 net full-time jobs created in Ontario (9.2 person-years of employment per $1 million capital investment);

These job creation numbers are estimates and are meant to be taken only as indications. It should also be noted that the capital cost per full-time job created is similar for all three scenarios ranging from $2.5 million per job under Scenario 2 to $2.7 million per job in Scenarios 1 and 3. Given the accuracy of these number (+/- 20% at best), the cost per job created can be assumed to be equal under all scenarios.

TABLE 3-6 BUILDING ENERGY EFFICIENCY AND ALTERNATIVE FUEL SCENARIOS

Scenario	Electricity Displaced Relative to Business as Usual 2031 (GJ/yr)	Natural Gas Displaced Relative to Business as Usual 2031 (GJ/yr)	Total Amount of Energy Reduced (GJ/yr)	Electricity Emissions Avoided Relative to Business as Usual 2031 (tonnes CO_2/yr)	Natural Gas Emissions Avoided Relative to Business as Usual 2031 (tonnes CO_2/yr)	Total Amount Emissions Avoided (tonnes CO_2/yr)	Total Capital (Cost $)	Total Annual Energy Cost Saving ($)	Net Full Time Job Positions Created from Scenario	$ Capex per Gross Full Time Jobs Created from Scenario
Maximizing the application of cost effective building energy efficiency improvements and technologies with an internal rate of return (IRR) of at least 6%.	10,050,000	2,986,000	13,036,000	73,000	168,000	241,000	$8,918,000,000	$203,000,000	3,400	$2,616,000
Maximizing GHG reduction using proven technologies with a cost of under $78/tonne of GHGs reduced.	10,050,000	2,986,000	13,036,000	73,000	168,000	241,000	$8,918,000,000	$203,000,000	3,400	$2,616,000
Maximizing the reduction in the consumption of fossil fuels.	11,259,000	27,517,000	38,776,000	82,000	1,544,000	1,626,000	$13,181,000,000	$323,000,000	6,200	2,730,000
	Electricity Consumption (GJ/yr)	Natural Gas Consumption (GJ/yr)	Total Annual Energy Use (GJ/yr)	Electricity Emissions (tonnes CO_2/yr)	Natural Gas Emissions (tonnes CO_2/yr)	Total Annual Emissions (tonnes CO_2/yr)				
Business as Usual	13,974,000	27,517,000	41,491,000	102,000	1,544,000	1,646				

Source: City of London IEMS Model. For a detailed overview of the methodology, see sections for Buildings, Technologies and Transportation in Appendix A. A detailed breakdown is provided in the separate Appendices document for London. Annual energy cost savings are based on current energy prices. The sum of the values for each category may differ from the total due to rounding.

4. Lowering energy demand with transportation efficiencies and technology

Communities can and do have a role in transportation planning and the associated trips that result from choices in land-uses and economic development strategies. Well integrated land-use and transportation plans can optimize the benefits of public and private investments in buildings and infrastructure and support energy-efficient choices for mobility.

For the IEMOC initiative, transportation efficiencies considered include improvements to both transportation demand management (TDM), as well as vehicle efficiency improvements.[30] This section reviews the potential impact of TDM strategies and vehicle efficiency opportunities (automobile and public transit) evaluated for London.[31]

4.1. Selecting transportation levels of efficiency

To assist with evaluating the potential to maximize the reduction of fossil fuels for transportation, the IEMOC team selected transportation strategies for lowering associated energy consumption and GHG emissions for vehicles and for public transit.

During the time that the L-IEMS was under way the City of London was working on the City's Transportation Master Plan to develop a Macro transportation simulation model. Three scenarios being evaluated as part of the TMP were also used as inputs for the Business as Usual, High Efficiency and Ultra High Efficiency transportation scenarios and are outlined in Table 4-1 below.

[30] TDM employs a range of techniques, such as encouraging fewer trips through incentives, developing and using options to avoid driving alone, ride-sharing, locating destinations closer to where people live and work, and putting more people within walking distance of needed local goods and services to access on a daily or weekly basis.

[31] Goods movement (local freight) was not incorporated as part of the IEMOC initiative or the L-IEMS. Further analysis on the impact of goods movement is important for London, which has large amount of freight being stored and transported due to his proximity to the 401 and U.S.

TABLE 4-1 TRANSPORTATION IMPROVEMENT CASES EVALUATED

Variables	Existing 2010	Transportation Business As Usual (T-BAU)	Transportation High Efficiency (T-HE)	Transportation Ultra High Efficiency (T-UHE)
Transit – mode share	Load Factor of 17.49* Transit person trip / capita: 9.7%	Load Factor of 17.49* Transit person trip / capita: 10%	Maintain existing load factor of 17.49* Transit person trips / capita 15%	Maintain existing load factor of 17.49* Transit person trips / capita 20%
Walk – mode share	Walk person trip / capita: 8.1%	Combined cycle and walk person trip / capita: 9%	Combined cycle and walk person trip / capita: 11%	Combined cycle and walk person trip / capita: 13%
Cycle – Mode Share	Cycle person trip / capita: 0.6%			
Fuel Fleet Efficiency	Car: 3.27 MJ/VKT Bus: 6.744 MJ/VKT	No change	Approximately 25% reduction in blended vehicle efficiencies (GJ/VKT)	Approximately 50% reduction in blended vehicle efficiencies (GJ/VKT)
Trip Length	Based on existing London survey data	No change	Average trip length reduction per zone of 5%	Average trip length reduction per zone of 10%
Trip Making	Based on existing London survey data	No change	Overall number of trips reduced by 5%	Overall number of trips reduced by 10%
Auto Occupancy	Based on existing London survey data Home Based Work Trips = 1.08 Home Based "Other" Trips = 1.31 Home Based Secondary School Trips = 1.74 Home Based Post Secondary School Trips= 1.55			

*Note: As load factors were not available for London, load factors taken from Canadian Urban Transit Association's 2007 Canadian Transit Fact Book for the city of Guelph were used.
Source: IEMOC study standard efficiency variables adjusted for London.

4.2. EVALUATING TRANSPORTATION IMPROVEMENT OPTIONS TO 2031

Table 4-2 provides a summary of the potential energy savings and emissions reductions that could be achieved under the transportation scenarios evaluated.

For instance, if all demand improvements were achieved for T-UHE (which includes the reduction in trip length, trips generated and increases for walking, cycling, carpooling and transit), London's total annual kilometres travelled by personal vehicle would be reduced by 18% resulting in an estimated 15% reduction in both energy use from transportation and associated emissions.

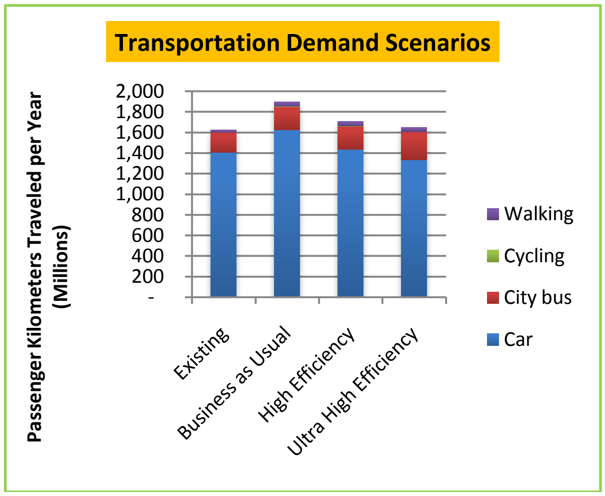
Incorporating potential vehicle efficiency improvements including 80% of gas powered personal vehicles being replaced with hybrids and another 20% with electric vehicles or plug-in hybrids the associated reduction in transportation energy and GHGs would be 54% and 57% respectively compared with BAU.

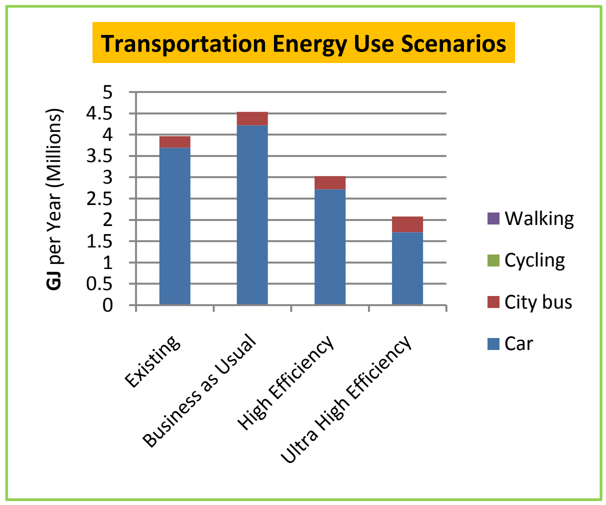
Figure 4-1 reviews the impact of TDM strategies and vehicle technology and fuel efficiencies for each transportation scenario evaluated. TDM measures and vehicle technology and fuel efficiencies could achieve a total reduction of 2,452,000 GJ/yr compared with BAU transportation energy use in the T-UHE case. This corresponds with a reduction of 180,000 tonnes of CO_{2e} savings per year.

As noted in previous transportation studies, dependence on personal vehicles is largely the result of community design. Lower density housing and the dispersion of employment opportunities not connected to any form of rapid transit has contributed to a pattern of travel less focused on moving people to downtown areas, making it difficult to service by transit. Across Ontario, including London, it is anticipated that people will continue to have a strong preference for personal vehicle use and that achieving an increase in transit ridership, carpooling, walking and cycling will require a concerted effort to encourage compact, mixed use urban form that reduces the need to get into a vehicle and to create transportation networks that give priority to active transportation.

For London, which is committed to re-urbanization within the downtown and intensification in greenfield development, emphasis should remain on creating pedestrian friendly environments that will give residents and employers the ability to reduce car use and engage safely in all aspects of their everyday lives, within walking distance and within easy access. At the same-time, emphasis should continue to be placed on advancing the use of energy efficient or hybrid vehicles and ensuring that the appropriate electrical infrastructure is in place across London.

Figure 4-1 Transportation Demand and Energy Use Scenarios





Source: City of London IEMS Model

Transportation Energy in Greater London

London is located within the larger South Western Ontario region and impacts and is impacted by the travel behaviours of neighbourhing communities. As such, travel behaviours of some neighbouring cities, towns and townships within the Middlesex and Elgin Counties have been captured in the City's travel survey.

TABLE 4-2 TRANSPORTATION VEHICLE EFFICIENCIES DISPLACING ENERGY TO 2031

Transportation Scenario	Units	Personal vehicle	City Bus	Cycling	Walking	TOTAL
Existing	VKT/yr	1,129,700,000	11,152,000	2,630,000	25,037,000	1,153,906,000
	GJ/yr	3,646,000	271,000			3,917,000
	Tonnes CO_2/yr	253,000	19,000			273,000
Business As Usual	VKT/yr	1,291,400,000	12,713,000	2,824,000	43,967,000	1,350,904,000
	GJ/yr	4,223,000	309,000			4,532,000
	Tonnes CO_2/yr	293,000	22,000			316,000
High Efficiency	VKT/yr	1,138,800,000	13,012,000	2,824,000	43,971,000	1,198,607,000
	GJ/yr	2,715,000	313,000			3,028,000
	Tonnes CO_2/yr	181,000	23,000			203,000
Ultra High Efficiency	VKT/yr	1,060,900,000	15,380,000	2,824,000	43,975,000	1,123,080,000
	GJ/yr	1,711,000	369,000			2,080,000
	Tonnes CO_2/yr	109,000	26,000			135,000

Source: City of London IEMS Model. For a detailed overview of the methodology, see section on Transportation in Appendix A.

For the purposes of the L-IEMS, only those trips originating within the City's municipal boundary have been included in the analysis. Based on data and assumptions as documented in the detailed methodology (Appendix A), only trips and associated energy and emissions generated by those residents starting within the City boundary were included in the model. These trips account for about 66 percent of all personal trips captured within the City's travel demand survey and transportation survey, but only about 34 percent of all vehicle-kilometres travelled for trips made by residents of the greater London area.

Given that the distances between origin and destination zones for those living in neighbouring areas of London are considerably longer than for London residents, it is estimated that these commuters account for approximately 2/3rds of energy consumed for personal transportation within the greater London area.

This is consistent with the information that the City of London has obtained for retail sales of fuels within London, which indicated that about 13,700,000 GJ of fuel was sold at gas stations in London in 2008, compared to the 3,900,000 GJ estimated for personal trips starting within the City boundary.

Based on these findings, the City of London should continue to develop transportation demand management strategies that consider not only needs and behaviours of London residents, but also those in neighbouring communities.

Figure 4-1 illustrates the variation in energy use for transportation per capita in London in 2010. Figures 4-2 and 4-3 illustration the distribution of energy use under BAU and UHE transportation cases.

FIGURE 4-1 LONDON TRANSPORTATION ENERGY USE MAP

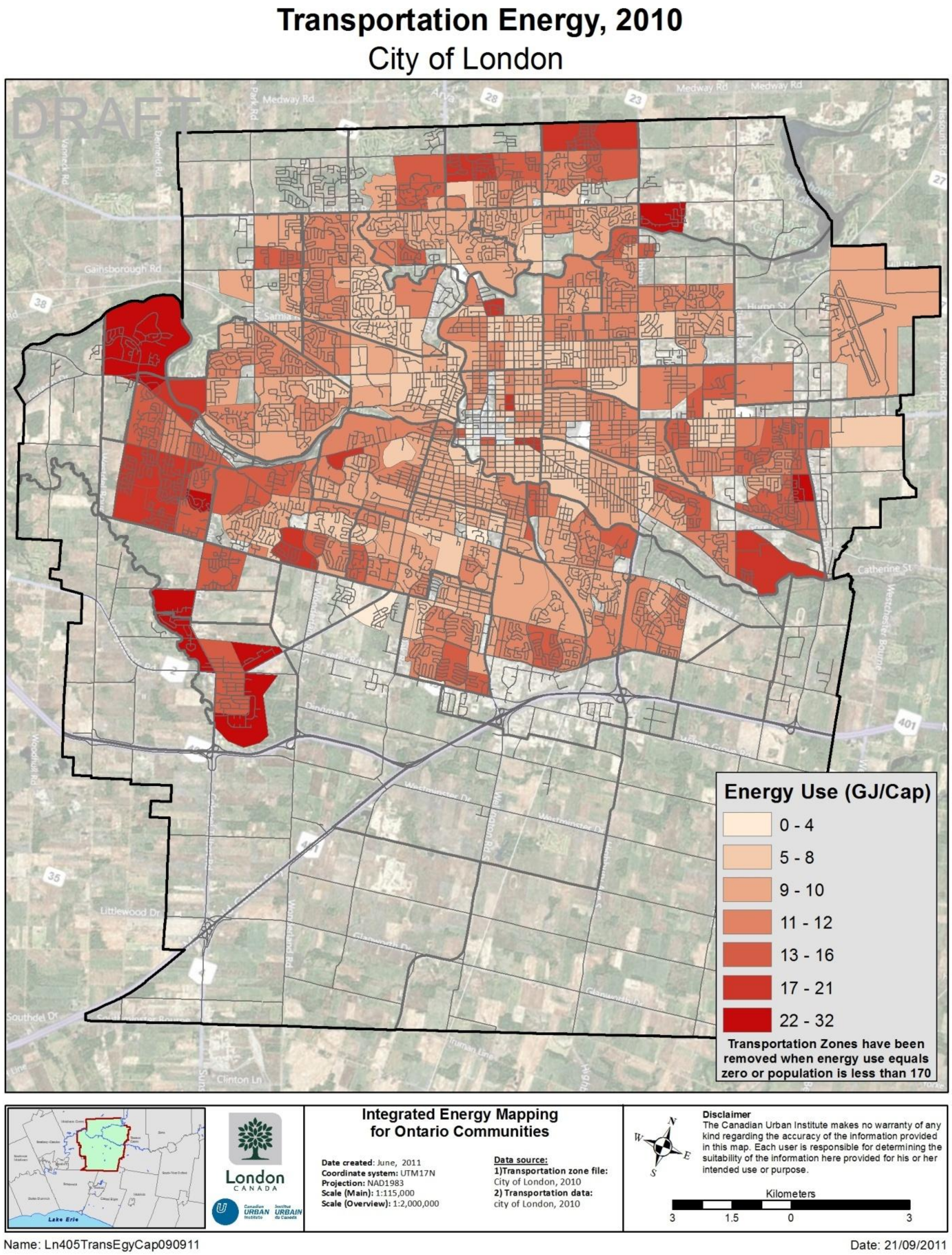


FIGURE 4-2 LONDON TOTAL ENERGY USE BAU 2031 MAP

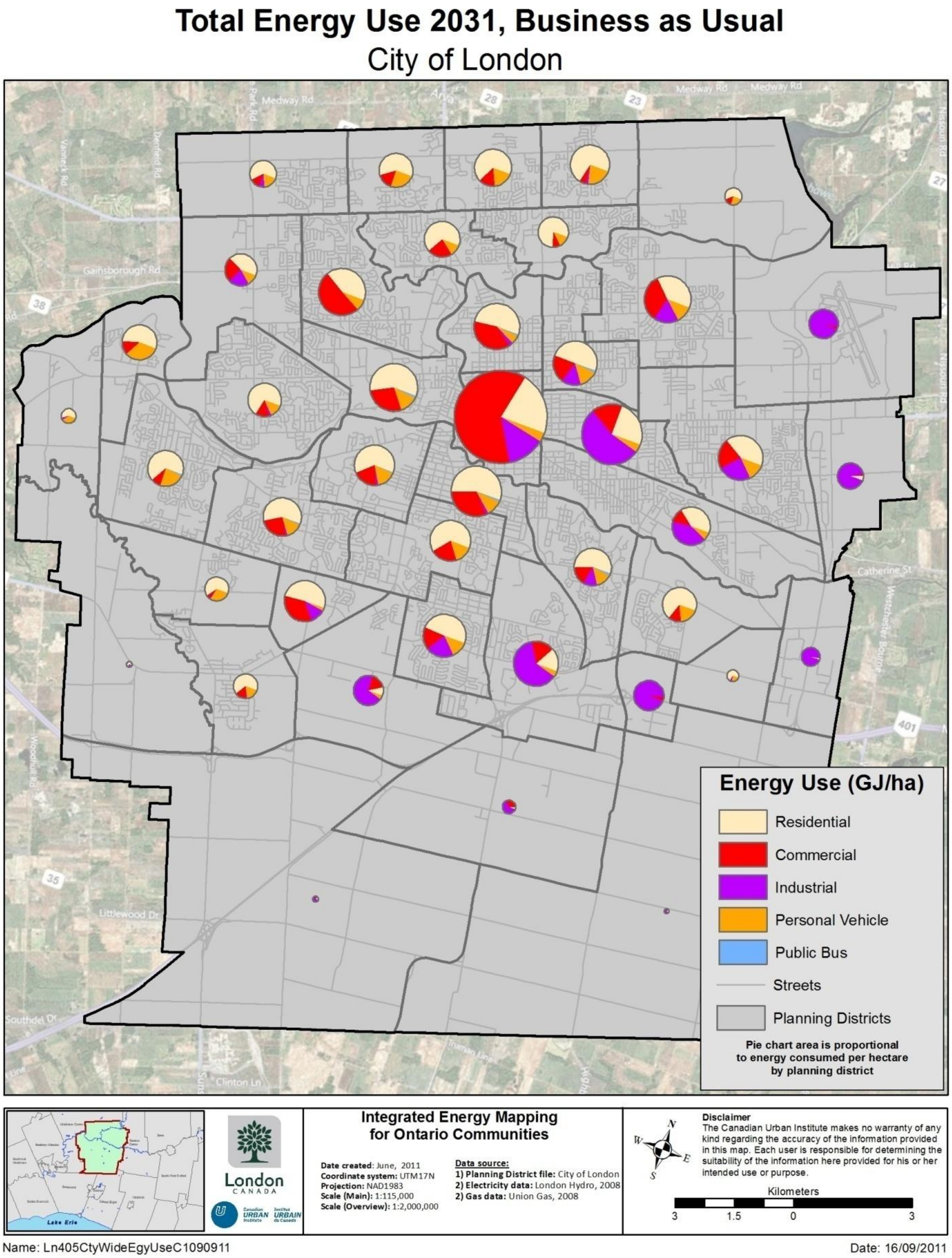
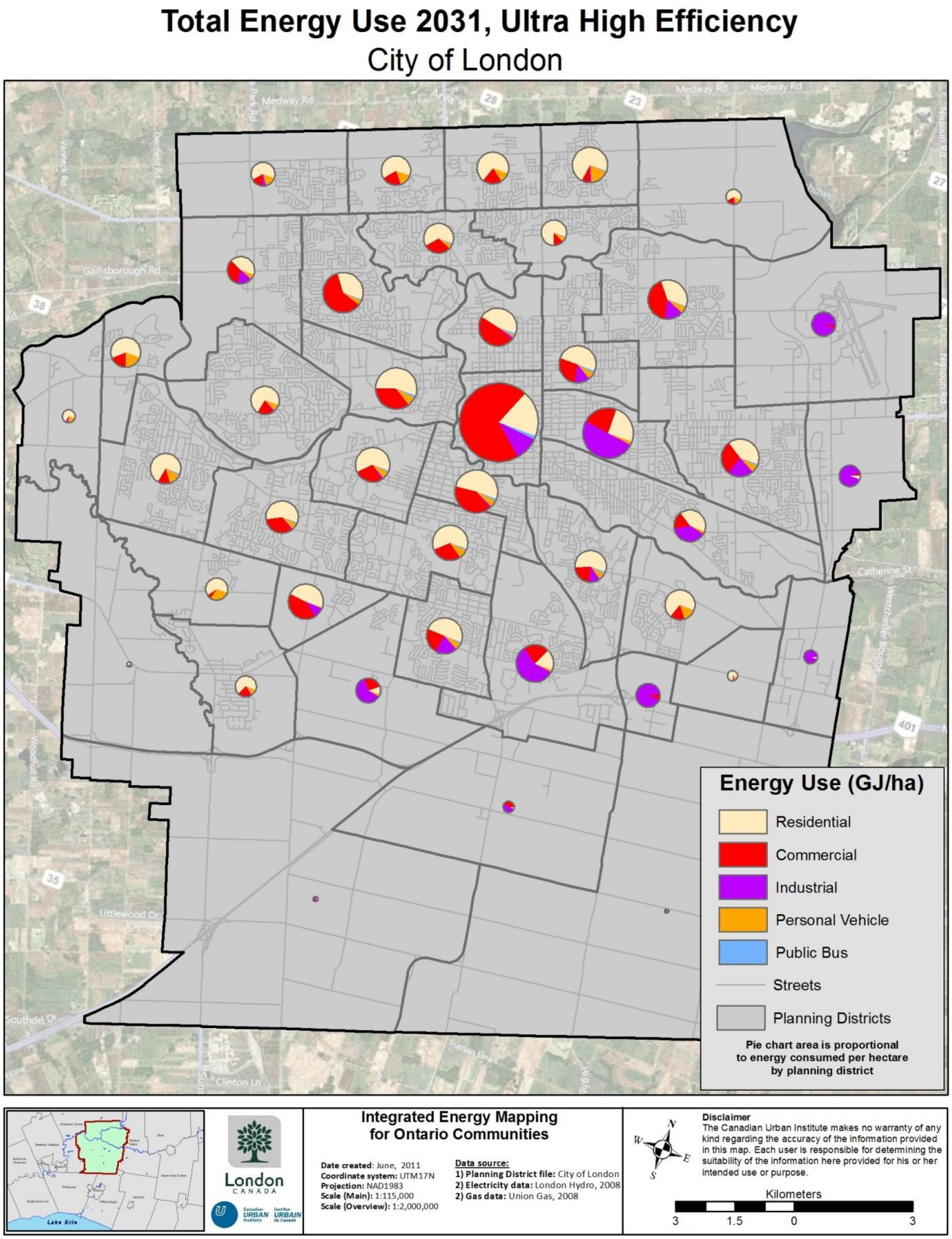


Figure 4-3 London Total Energy Use UHE 2031 Map



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Date: 16/09/2011

5. Advancing energy efficiency in London

For the 5400 communities across Canada, the importance placed on advancing energy efficiency varies relative to access to resources, concerns about affordable energy and climate change, and the ability to coordinate effectively with local or regional utility authorities. This section begins with an overview of some of the key insights identified during the evaluation of energy efficiency strategies and concludes with three immediate steps the City of London can take to advance energy efficiency.

5.1. Key areas of focus for London

Through the activities of the L-IEMS, key insights and potential focus areas in terms of energy efficiency opportunities were identified for transportation in Table 5-1 and built form identified in Table 5-2.

Existing Built Form

As an established city, London has a wide range of housing types with regards to year constructed with a number of larger older homes in old London built as early as the 1840s. Existing low rise development comprises about 52% of London's total building stock today by building space. Although advancing energy efficiency improvements in existing residential buildings would require some form of assistance (e.g., the current federal ecoENERGY Retrofit - Homes program), the potential to reduce energy and GHG emissions across the City is significant. The energy efficiency improvements considered are small in nature, ranging from lighting and water fixture replacements to furnace upgrades and building envelope improvements, but when aggregated across a City can lead to significant GHG emission reductions.

To maximize the potential for energy efficiency improvements of existing residential building stock, further analysis should be considered in cooperation with London Hydro and Union Gas. The analysis can draw directly on the energy mapping resources and tools prepared as part of the L-IEMS to help better target demand side management and conservation demand management activities across London that build upon existing tools. The analysis should give more detailed consideration if larger scale building types, such as manufacturing and older industrial manufacturing could benefit from energy efficiency improvements.

Three other larger users of energy in London include commercial retail, industrial and institutional buildings. In terms of commercial retail and institutional, London is above the provincial average. This reflects that London has a larger number of university and college buildings (University of Western Ontario, Fanshawe College and others). London also has an established industrial/light manufacturing sector. Energy mapping can be used to help refine the analysis and identify specific buildings that could provide larger scale energy reductions and contribute to local economic competitiveness.

Projected Built Form

Although the City of London is projecting a modest growth of 1-2% per year, new development is expected to be relatively distributed across major corridors, nodes and limited greenfield areas of the City. One of the major strategies for reducing energy consumption is to lower new demand to the lowest level possible. This reduces overall increases in energy consumption for London and makes available more resources to resources to be redirected to reducing energy use in existing buildings.

By investing in higher building efficiency now, homeowners and businesses can avoid costly retrofits in the future. Although the rate of return for most residential building types examined for London was low, the overall potential for reductions in energy and GHG emissions was moderately high.

The City is actively evaluating how new planning tools and policies can be applied to advancing energy efficiency. Recently, the City completed a report, *London Green Incentives,* with support from the OPA that examines the types of incentives and policies that can be used to advance green development for greenfields, urban redevelopment and building level retrofits. This work is expected to contribute to forming a London-specific Green Development Strategy.

Consideration should be given to using available regulatory tools to help advance the application of higher efficiencies, particularly for institutional, commercial and industrial development where there is a positive return. For instance, the use of Community Improvement Plan for the expansion of an industrial or commercial park area, or encourage the use of power of subdivision to maximize passive solar gain in terms of built form layout or higher agreed to building energy efficiency levels.

Consideration should also be given to advancing the application and use of community energy systems and other technology and fuels with a positive return to meet the heating, cooling and power demands of new development. Consideration should be given to existing areas of high thermal demand, such as industrial areas and the downtown area of London where new development is also expected. These areas are expected to have a good combination of building types that have complementary energy demands and schedules that are known to support the expansion of the existing downtown district energy system or the creation of new district energy systems.

Transportation

London is evaluating a wide range of transportation options and growth patterns. Consideration should be given to including the potential energy reductions that can be attributed to the application of TDM strategies and other initiatives as modelling analysis is undertaken both within London and within the Greater London area.

TABLE 5-1 LONDON TRANSPORTATION ENERGY EFFICIENCY INSIGHTS

Transportation Improvements			
Strategy	**Cost effectiveness**	**Impact on emissions reductions**	**Strategies for Improvement**
Transit and transportation demand management	Not examined.	Medium (48 000 tonnes CO_2).	Average trip length reduction, increased personal vehicle occupancy, reduced number of trips and increased transit ridership.
Vehicle efficiency	Not examined.	Very high (133 000 tonnes CO_2)*.	100% market uptake of hybrid and electric personal vehicles and biodiesel City buses.

*Assumes high efficiency vehicles on top of reduced transportation demand scenario

For London, the application of improved vehicle efficiency in terms of hybrids and electric vehicles can greatly reduce the potential for energy use and GHG emissions in the future for London. This is a result of the transition of Ontario's electric grid to a low carbon emission grid.

The ability to benefit from a lower carbon emission grid will be dependent on the ability for local electrical infrastructure to accommodate EV recharging stations and the ability to access these recharging stations. Opportunities also exist to benefit from the use of biomethane capture and its application for fuelling vehicles in London. Consideration should be given to working with London Hydro and Union Gas to evaluate the capacity for electrical infrastructure and charging station capacity, and access to alternative clean burning fuels for use in local corporate fleets.

TABLE 5-2 LONDON BUILDING ENERGY EFFICIENCY INSIGHTS

Building Improvement Strategies			
Strategy	**Cost effectiveness (based on High Efficiency Scenario)**	**Impact on emissions reductions (based on Ultra High Efficiency Scenario)**	**Strategies for Improvement (based on Ultra High Efficiency Scenario)**
Residential existing building retrofits	City wide - low (-3% IRR) for average housing. Opportunity to use mapping to target the most cost effective retrofits.	Potentially very high for existing low density housing (158, 000 tonnes CO_2/yr). Small improvements on a large scale could have a potentially significant impact.	Simple improvements (high efficiency scenario) include light bulb and water fixture replacements. Deeper retrofit opportunities (ultra high efficiency) include window replacements, furnace upgrades and additional roof insulation.
Residential new construction	Low for low density new construction (~-6% IRR). Low for new construction of multi unit residential buildings (~-1% IRR).	Medium for low & medium density residential new construction (25, 000 tonnes CO_2/yr). Low for high density residential new construction (6, 000 tonnes CO_2/yr).	Ontario Building Code will increase standard building efficiency above current levels. Additional opportunity to encourage higher window performance, increased boiler efficiency, increased insulation levels in walls and roofs, heat recovery and water use reduction in single family, semi detached and row houses. Apartments can achieve higher energy performance by also increasing insulation levels in walls and roofs.
Commercial existing building retrofits	Low for office retrofits (0%), medium for retail (~5%)	Low (21, 000 tonnes CO_2) for commercial office and retail.	Opportunity for electricity savings through lighting retrofits and natural gas savings through boiler retrofits, water use reduction and heat recovery.
Commercial new construction	Very high for new office (~20%); low for retail (~1%).	Medium (58, 000 tonnes CO_2).	New construction can include high efficiency central plants (heating, cooling , domestic hot water), variable air volume (VAV) HVAC systems (in place of conventional constant volume retail systems), lighting controls, water use reduction, and envelope upgrades (window, wall and roof) to lower annual electricity and natural gas consumption.
Institutional retrofits	Low for both low density institutional (e.g., schools, police stations) and high density institutional (e.g., hospitals, universities) retrofits (-4%).	High (70, 000 tonnes CO_2).	Opportunity for electricity savings in existing facilities through lighting retrofits and natural gas savings through boiler retrofits, water use reduction and heat recovery.
Institutional new construction	High for both low and high density institutional new construction (7% and 11% respectively).	High (42, 000 tonnes CO_2).	New construction and additions can include high efficiency central plants (heating, cooling, domestic hot water), lighting controls, water use reduction, and envelope upgrades (window, wall and roof) to lower annual electricity and natural gas consumption.
Industrial retrofits	Medium for industrial retrofits (~5%).	Very high (121, 000 tonnes CO_2).	Opportunity for electricity savings through lighting retrofits and natural gas savings through boiler retrofits, water use reduction and heat recovery.
Industrial new construction	High for industrial new construction (~11%).	Low (7, 000 tonnes CO_2).	New construction and additions can include high efficiency central plants (heating and domestic hot water), lighting controls, water use reduction, and envelope upgrades (wall and roof) to lower annual electricity and natural gas consumption.

5.2. Three immediate steps to advance energy efficiency in London

The City of London, local utilities, businesses, and community members are actively advancing energy efficiency activities related to alternative energy supply, high performance buildings, sustainable transportation options, and long-range energy planning.

At the municipal corporate level, the City of London is working closely with residents and businesses across the greater London area to understand the challenges and opportunities for energy efficiency through the RETHINK Energy London Consultation. The initiative is centred on the development of an action plan for advancing energy efficiency and the reduction of GHG emissions. The City is also encouraging the improved energy performance of municipal buildings by adhering to the Leadership in Energy and Environmental Design (LEED) rating system. As well, the City has contributed to the establishment of an advanced energy efficiency project with homebuilders by hosting two pilot projects in coordination with CANMET Energy, a division of NRCan.

In cooperation with local businesses, the City is also undertaking to lower energy use and the associated GHG emissions from transportation through innovative partnerships. A recent pilot initiative, the Business Travel Wise Program, engaged 24 businesses to support more sustainable forms of commuting. There are now 15 companies are continuing the program representing about 14,000 employees. A full list of the energy efficiency activities being undertaken by the City is provided in Appendix 3.

London Hydro and the City are continuing to coordinate on a number of initiatives to advance renewable energy in London. The joint initiatives include installing four 10kW Solar PV Tracking systems and forming a Solar Rooftop Partnership to support up to 9 different initiatives for 100-500kW. London Hydro is also undertaking a number of energy efficiency activities that are being supported by the OPA for commercial, industrial, and residential customers to meet conservation demand management (CDM) targets.

Union Gas is also working with the City of London to advance energy efficient opportunities. Initial activities include the first application to support upgraded landfill gas as a GHG-neutral activity (biomethane) to be used in the local natural gas distribution network for London. Union Gas is also undertaking to deploy strategic demand side management activities (DSM) across the city.

These initiatives demonstrate that London is already positively advancing energy efficiency and that this initiative can be expanded through three next steps.

Step One: Develop an Action Plan with Key Stakeholders and Utilities

Action: *Prepare a consolidated action plan that sorts out who among the energy players ought to do what in London's energy future and create a road map for advancing selected energy/GHG activities.*

The City of London has followed the process established by the FCM Partners for Climate Protection to meet municipal GHG and energy goals. There are five milestones for this initiative, including the development of a GHG inventory, the establishment of a GHG target, the review and selection of strategies and options for meeting GHG targets, and the development of an action plan to meet GHG targets. The L-IEMS serves to contribute to updating components of London's GHG emissions inventory and to informing the associated initiatives and related costs to meeting the provinces of Ontario's GHG targets. As well, the L-IEMS has undertaken to evaluate a range of energy efficiency strategies for built form and transportation that can be integrated into a GHG action plan.

The City has also undertaken an extensive engagement process through RETHINK London Energy that has identified a number of potential initiatives. As part of the FCM PCP process, the next step is for the City of London to develop a new action plan that sets out specific activities of a policy, program or partnership activity and a timeframe for accomplishment.

The L-IEMS, RETHINK London Energy and Smart Moves 2030 Transportation Master Plan all identify a range of activities for advancing energy efficiency at a corporate and broader community level. An important next step as part of the action planning process will be to divide out municipal corporate and community actions. Starting in 2013, the broader public sector (municipalities, hospitals, school boards etc) will be expected to begin reporting regularly on its energy and GHG emissions to the province of Ontario and will also need to development a plan to demonstrate conservation activities.

London's action plan can serve as the starting point to develop consensus on the objectives for energy and GHG reduction and contribute to forming a comprehensive implementation initiative for corporate and community initiatives with related partners for energy efficiency across the city.

Action: *Prepare indicators to measure progress towards targets. Indicators should capture the contribution of all energy programs, projects and policies underway in London.*

Indicators provide a consistent way to monitor and measure progress. The selection of indicators is important for ensuring increased consistency of measurement across a municipality at a level that provides meaningful information to residents, businesses, and others. There are three types of indicators. The first is "lagging indicators", which measure outputs (in terms of tonnes of GHGs). The second type of indicator is a "leading indicator". This type evaluates actions expected to lead to improved environmental performance. The third type of indicator is referred to as environmental condition indicators. These indicators measure the direct effect of an activity on the environment. All indicators have their strengths and weaknesses and appeal to different types of audiences. Subsequently, a mix of indicators is often used to evaluate progress and to monitor baselines. Indicators are most effective when they are directed to a particular audience. For instance, business owners may be less interested in total energy use per hectare and more interested in how their individual energy use compares to other companies of a similar operating nature. We suggest that metrics be developed into three categories:

- general audience,
- economic development, and
- planning and monitoring.

For a general audience, the common approach taken to identify metrics involves asking residents what they would want to know. It is important that the metrics identified are relevant and of value to people in London. The same approach can be taken for economic development. These metrics are best identified during the engagement activities to be undertaken as part of a developing an action plan

For general monitoring purposes at the broader municipal level, three metrics for consideration include:

Indicator 1: Total energy used for buildings. This would measure building energy use and capture the benefit of DSM/CDM programs and other energy efficiency initiatives. Total energy used would include energy used to generate space heating/cooling, domestic hot water and electricity. The indicator could be broken down by Planning District, transportation zone, dissemination area or another suitable level of geography. One of the more useful levels of evaluation is at the neighbourhood level for comparison purposes.

Metric: Average GJ/m2/yr or GJ/unit/yr or GJ/cap/yr

Indicator 2: Total energy used for transportation. This would monitor overall transportation related energy use and capture the deployment of TDM initiatives. Total energy used would include private vehicle use, transit and goods movement (if data is available). The indicator would be broken down by Planning District, transportation zone, dissemination area or another suitable level of geography.

Metric: Average GJ/VKT

Indicator 3: Use of renewable fuels and technology. Renewable energy fuels and technology indicates the degree to which a development is able to meet electrical thermal energy demand from renewable energy sources.

Metric: Percentage of total energy consumed that will be generated from renewable fuels and technology.

Action: *Use the Mayor's Sustainable Energy Council (MSEC) to move forward energy efficiency and GHG actions.*

The cities of Toronto, Hamilton, Ottawa, Guelph, and Barrie have all formed advisory bodies to advance energy strategies put forward in a GHG or community energy plan. In Guelph, the Mayor's Task Force is being used to advance the implementation of identified initiatives in the Guelph Community Energy Plan. Members of the committee have opted to identify what specific sector targets could be addressed by their individual knowledge or core areas of expertise. Guelph Hydro was identified as being the lead agent for the City to meet its alternative and renewable energy target contribution. In Hamilton, a collaborator committee comprised of city council members and local energy stakeholders is in the process of developing longer term energy plans. MSEC is well placed to advance the implementation of any action plan and contribute to ensuring a coordinated and successful approach with local utilities and community stakeholders.

Step Two: Build on Information for Integrated Energy Mapping

Action: *Work with London District Energy to apply available energy information to target system expansion in downtown London.*

Relative to the timing of the L-IEMS, information available for detailed analysis of district energy was limited to existing total energy use. With the completion of a detailed analysis of building types for all of London and information collected on existing energy and electricity use, a more thorough analysis of the potential for district energy expansion across the downtown areas should be considered.

Specifically, the analysis should incorporate peaking and seasonal data. In addition, detailed data can be accessed from the Municipal Property Assessment Authority (MPAC) related to existing heating systems and building ages. This information can be mapped against existing heating demand and analysis evaluated for the potential to expand London's district energy information.

Action: *Incorporate urban forest data into energy mapping to produce shade target map.*

Trees provide a direct dual benefit of helping to improve air quality and provide much needed shade, which can reduce the amount of energy needed to cool a building and lower the amount of indirect heat generated from dark surfaces, such as asphalt and concrete sidewalks. During the energy mapping workshop, it was identified that trees could start to be seen for their potential to reduce cooling loads across the City. During the session, it was also identified that London's urban forest was synonymous with energy conservation and developing a more sustainable city. To encourage more investment in the urban forest, and to evaluate the potential to use site specific policy options for locating trees within new developments, mapping the cooling contribution potential of trees was identified as a viable approach. Similar activities have been undertaken in Toronto where surface heat temperature was correlated with different land-use types. Significant temperature differences across Toronto were noted where a high tree canopy existed.

Action: *Work with local utilities to identify commercial and industrial buildings types with highest or most variable annual or peak electricity/gas demands.*

In addition to supporting conservation and demand management decision making, verified energy use maps can help energy planners to identify neighbourhoods of high energy density and compatible load profiles that could support district energy systems and identify priority neighbourhoods for retrofit activities. Limited analysis was undertaken with electricity and natural gas data collected during the L-IEMS in terms of prioritizing potential sectors and sub-sectors for evaluation related to DSM and CDM activities. For the L-IEMS activity, peak electricity and gas data was not incorporated into the assessment. This information would provide an important starting point for advancing with a more targeted and, potentially, significant opportunity for reducing either energy or electricity consumption.

Action: *Work with local utilities to resolve potential outliers identified during integrated energy mapping exercise.*

To ensure that the City of London is able to measure and verify the impacts of DSM and CDM initiative, an agreement should be arranged with the local utilities of London Hydro, Union Gas, and London District Energy for providing on-going data. This agreement would need to address the issues of privacy and the sharing of licensed data.

London Hydro, Union Gas, and London District Energy have been very supportive of the City's energy mapping initiatives. At the same time, the format for how data is being shared is leading to the identification of outliers (buildings with high values for either electricity or natural gas or unusual variations for energy use). There are a variety of potential reasons for this. For instance, it could be that identified higher energy consuming buildings or neighbourhoods are just using more energy.

Alternatively, it might be the way buildings are classified by local distribution companies and by municipalities (each does it differently).

One of the immediate directions would be to continue working with Union Gas to match gas customers to MPAC parcel data prior to aggregation.

Step Three: Invest in the Resources and Knowledge to Advance Energy Efficiency

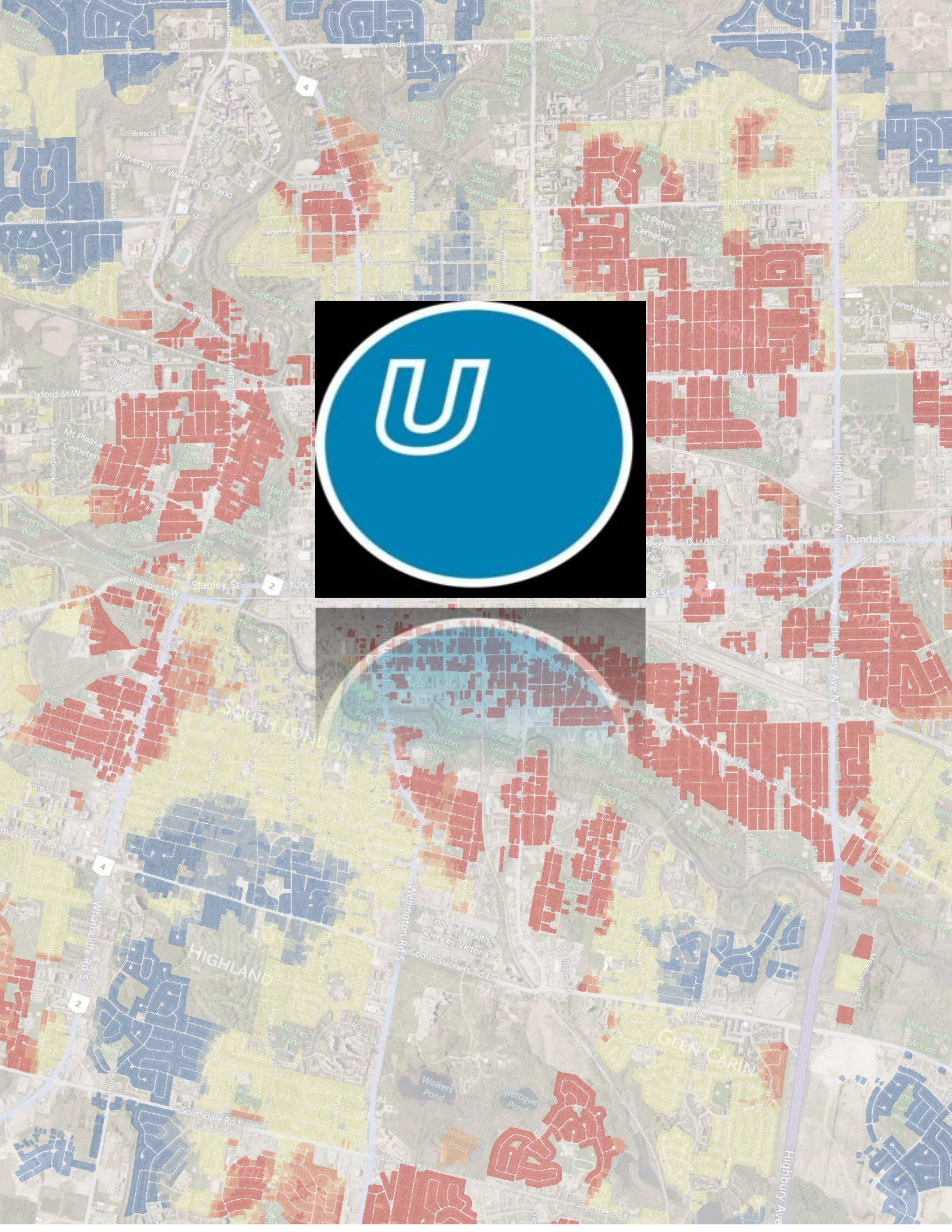
Action: *London should establish a position to manage the development and delivery of actions with respect to community energy.*

To date energy use and energy use data have formed the bases of London's air quality and climate change programs and actions. These initiatives are currently managed by the City of London's Air Quality Manager. The City should ensure that development, implementation and delivery of various energy management and greenhouse gas reduction programs citywide are within the influence of the Air Quality Manager. This City should also consider adjusting the title and terms of this position to reflect this responsibility. In other municipalities across Ontario and Canada this person is called a community energy manager.

Specifically, the community energy manager could be responsible to move forward on the Community GHG Inventory and similar energy studies, serve as a liaison on key initiatives such as the implementation of energy projects like district energy and other larger scale community programs, and lead policy implementation in the area of energy efficiency and fossil fuel reduction. Clarification on these roles and services would contribute to ensuring implementation and delivery of various energy management and GHG reduction programs at the community level.

Action:*London should collaborate with utilities to determine how to optimize the use of alternative energy sources (consider preparing an energy resource map – biomass, waste heat capture, conversion of local syngas sources etc).*

Asset mapping involves taking a broader inventory of assets in a community and apply exiting information to evaluate the contribution of alternative energy sources. For instance, the level of potential biomass can be evaluated in terms of access and production capacity for the greater London area. Other applications of GIS can include wind mapping, solar penetration, and biogas production. This information can be integrated with existing infrastructure support, such as the natural gas distribution network. A starting point for London would be to evaluate the local biomass potential, including biogas and methane capture potential from waste water treatment facilities, landfills and local light industrial activities (e.g. refinement of alcohol from breweries).



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University of Western Ontario
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Oxford St W
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Mt Pleasant Cemetery
Dundas St
Horton St W
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York St
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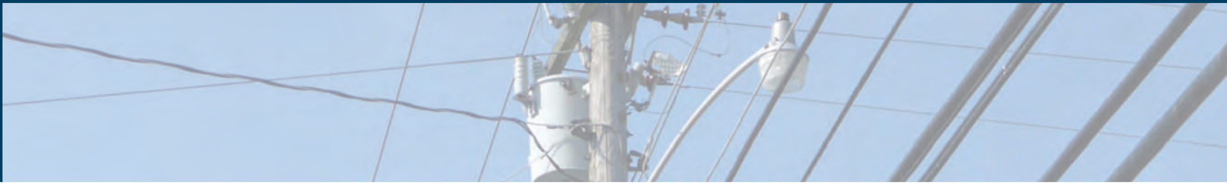
Commissioners Rd W
Wharncliffe Rd S
Highbury Ave N
Highbury Ave
Southdale Rd E
London Health Sciences Victoria
Walkers Pond
Thompson Road Park
Vauxhall Park
St Julien Park
South Branch Park
Watson Street Park
Chelsea Green Park
Euston Park
Centre St
Mitches Park
Fanshawe College
Stronach Park
Riverside Walk
Thames Park
Gibbons Park
Huron Street Conservation Area
North London Sports Fields North
North London Sports Fields South
Stoneybrook Recreation Field
Kilally Valley Park

File Number:	EB-2016-0091
Exhibit:	9
Tab:	1
Schedule:	11
Date Filed:	August 26, 2016

APPENDIX 5 OF 5
APPENDIX 9E ELECTRIC MOBILITY ADOPTION AND PREDICTION REPORT



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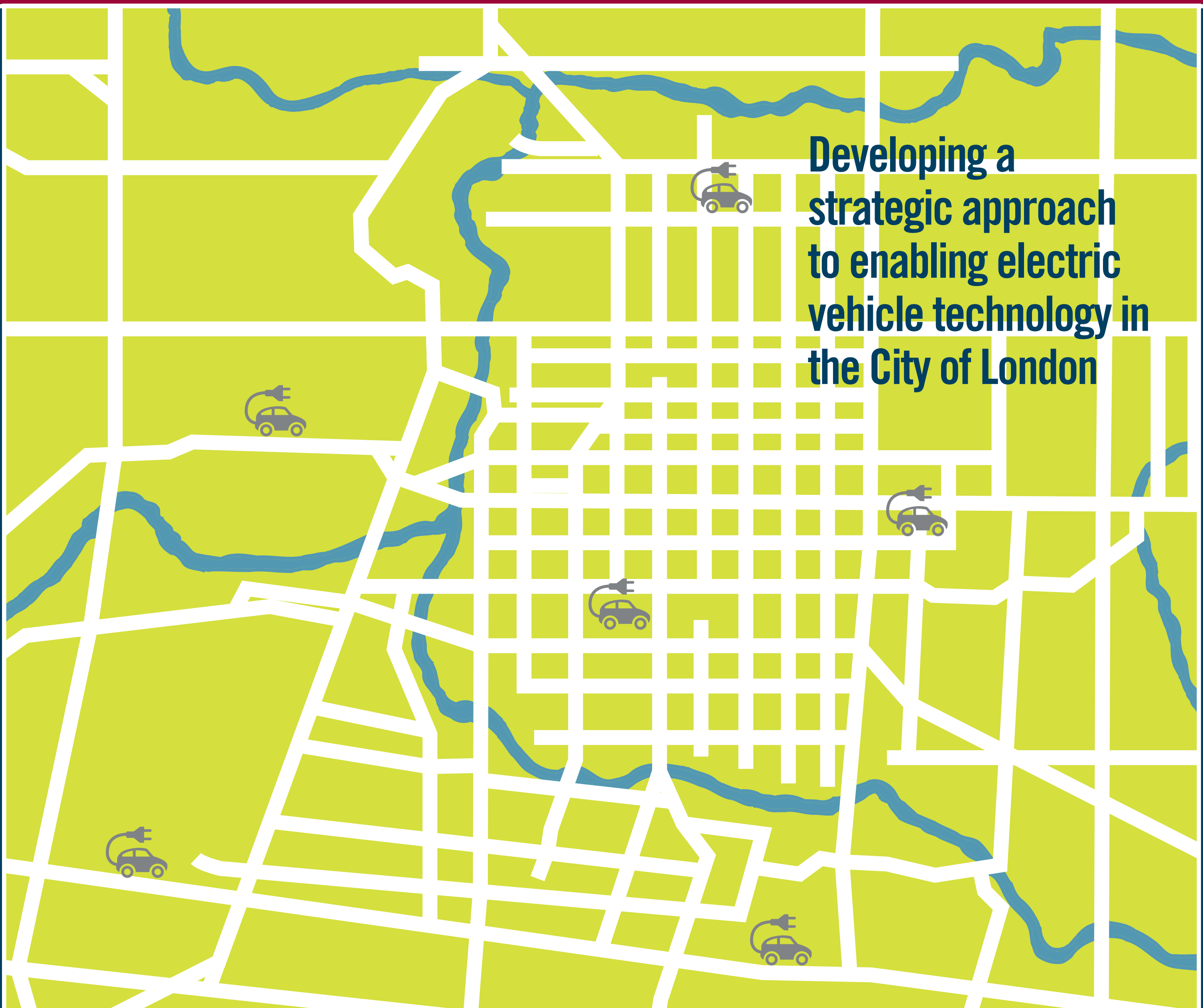
ELECTRIC MOBILITY ADOPTION AND PREDICTION



Developing a strategic approach to enabling electric vehicle technology in the City of London

ABOUT POLLUTION PROBE

Pollution Probe is a national, not-for-profit, charitable organization that exists to improve the health and well-being of Canadians by advancing policy that achieves positive, tangible environmental change. Pollution Probe has a proven track record of working in successful partnership with industry and government to develop practical solutions for shared environmental challenges.

ABOUT ELECTRIC MOBILITY CANADA

Electric Mobility Canada (EMC) is a national, not-for-profit industry association advocating for electric transportation as the primary solution to Canada's transportation sector issues. Established in 2006, EMC members include the automotive industry, infrastructure and battery suppliers, electricity providers, end-user fleets, research and development institutions, and others who strive to maximize Canada's green potential.

ABOUT LONDON HYDRO

London Hydro is an electricity distribution company serving the City of London, providing residents and business owners with a safe, efficient and reliable supply of electricity. The City of London is the sole shareholder of London Hydro. Electricity is delivered to the diverse customer base through an extensive network of overhead and underground power lines. This network is fully owned, operated and maintained by London Hydro. London Hydro is a progressive organization that has participated with local institutions of higher education in a number of joint projects, including investigating new technology and programs that may provide alternative energy sources and environmental benefits for the current and future generations.

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ELECTRIC MOBILITY CANADA MOBILITÉ ÉLECTRIQUE CANADA

London Hydro

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About This Report

Electric Mobility Adoption and Prediction (EMAP) combines sophisticated market research methodologies with detailed grid integration and impact analyses. The EMAP methodology is a tool of predictive analysis, capable of improving the efficiency of capital investments in electricity distribution system assets and electric vehicle (EV) charging infrastructure by ensuring that they align with the needs of early adopter markets.

In 2011, Pollution Probe collaborated with the Centre for Urban Energy (CUE) at Ryerson University on a pilot EMAP study for the City of Toronto. Building on the Toronto study, Pollution Probe partnered with Electric Mobility Canada and utilities in other Canadian municipalities (Ottawa; Hamilton and St. Catharines; London; Markham, Richmond Hill and Vaughan; and Calgary and Edmonton) to conduct further EMAP studies with support from the utilities and the ecoENERGY Innovation Initiative led by Natural Resources Canada. This report summarizes the application of the EMAP methodology to the City of London and the implications of the EMAP analysis for London Hydro, the local distribution company (LDC).

Representatives of stakeholder organizations integral to the future of electrified transportation in London met regularly as an advisory group for the study, contributing to the overall project scope, sharing technical expertise and providing guidance for all milestones and deliverables. The participation of these expert advisory group members helped to ensure that a local perspective informed the project, thus providing further credibility and enhancing the value and relevance of the outputs. This study also led to the production of a number of complementary reports, including full-length reports on the EMAP market research and the electricity distribution system assessment produced by Environics Research Group and London Hydro, respectively. Taken together, these resources provide a comprehensive look at the implications of EV technology uptake for London and served as the basis for this report.

This report proposes a set of strategic objectives and recommendations intended to prepare London Hydro to manage and support the use of EVs in its service area.

This report summarizes the process, findings and implications emerging from the London EMAP study. It also proposes a set of strategic objectives and recommendations intended to prepare London Hydro to manage and support the use of EVs in its service area.

Report Outline

This report describes the process, findings and implications of the EMAP study and explores options for a strategic path forward. The report is divided into three sections:

Section One provides a brief description of the EV as an emerging technology and proposes a three-point strategy for enabling EV use in London, based on key findings from the EMAP market research and electricity distribution system assessment.

Section Two describes the specific process, outputs and assumptions made in the development and application of the market research. This section builds a detailed picture of the characteristics of potential early adopters, including a broad demographic profile, typical personal mobility patterns, and the barriers to and opportunities for the uptake of EVs.

Section Three describes the methodology and results of simulation work conducted by London Hydro. The simulations address the capacity of the electrical distribution system at the neighbourhood level to support additional loading resulting from EV charging under a number of conditions.

SECTION ONE: A Strategic Approach to Enabling EV Use in London

The Electric Vehicle as an Emerging Technology

For EVs to become a viable part of a successful sustainable transportation system in the City of London, the social, environmental and financial needs of the user must be met. If early users of the technology are unable to experience and appreciate its full value, a broader market will not emerge. These early users will play a key role in expanding and developing the EV market and, for this reason, it is important to better understand exactly how to address their needs and incorporate the technology into their lives.

While the results of the EMAP study identify barriers and opportunities specific to EVs, the technology's adoption cycle also shares a number of characteristics with other emerging technologies. The process of technology adoption tends to follow a classical bell curve. The first users are known as innovators, followed closely by an early adopter group. Innovators are generally a very small number of risk takers who thrive on the challenge of a new technology and are willing to buy into a product even though the technology may ultimately fail. Early adopters, on the other hand, are generally more cautious in their adoption of a new technology and are not as willing to form new routines or behaviours to incorporate it into their lives. This observation is supported by the early adopter profile generated through the EMAP market research, which suggests that, in the City of London, this group is unaccustomed to inconvenience and perhaps somewhat reluctant to make the sacrifices they perceive to be necessary to transition to an EV, given current market and technological considerations.

Support or endorsement of a technology from the early adopter group is one of the most important factors contributing to its adoption by a broader market.

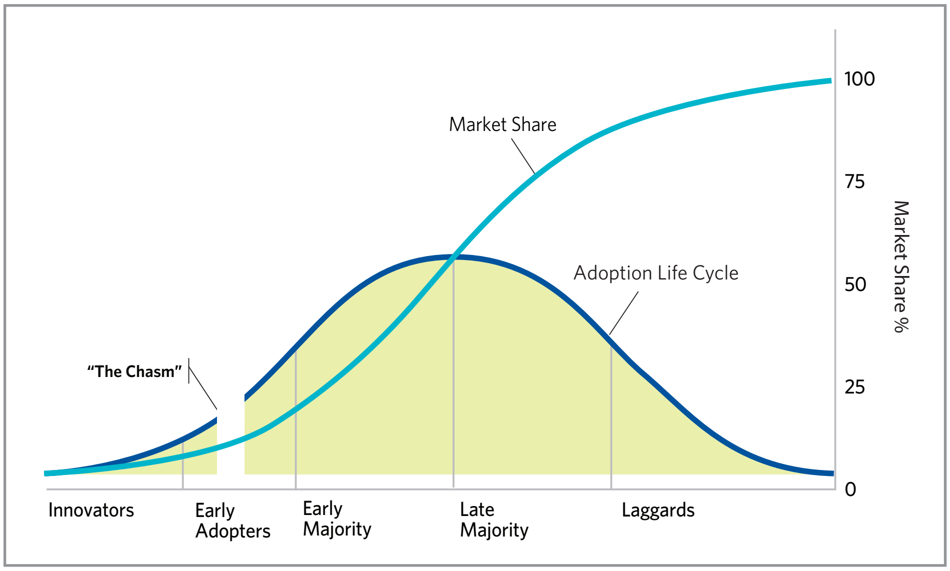
Support or endorsement of a technology from the early adopter group is one of the most important factors contributing to its adoption by a broader market. Whereas innovators may be perceived as extravagant or in a better position to take risks than the general public, early adopters demonstrate a high degree of opinion leadership capable of generating confidence in the usefulness of a technology among the broader public. The early majority of the mass market tends to take its cues and base its decisions on the experiences of and feedback from early adopters because their choices are perceived to be more discerning. It is for this reason that the EMAP study focuses on this influential consumer group.

While the traditional bell curve has long been the typical visual representation of market development for an emerging technology, more recently, Geoffrey Moore* has introduced the notion of a "chasm." Moore argues that there is a gap (or chasm) between the early adopter group and the early majority because the latter not only wants a useful product but also a well-established infrastructure to support it. Moore believes that, during the chasm phase, an emerging technology experiences a pause in market development. The length of this pause depends entirely on how disruptive the technology is to "business as usual."

**Crossing the Chasm: Marketing and Selling High-Tech Products to Mainstream Customers*. HarperCollins, 1991.

The actual market share held by an emerging technology does not follow the traditional bell curve for market development. Market share shows an upward trend before reaching full market saturation. This is because each adoption group is made up of a different number of people. For example, innovators and early adopters are relatively small groups and, as such, their interest in a technology translates into a relatively small percentage of the overall market. By the time the late majority and laggards adopt a technology, the market share is close to approaching saturation because these groups make up a much larger proportion of the population. See Figure 1.

Figure 1: Technology Adoption Life Cycle and Market Share



There have been many attempts to forecast the rate at which the adoption of EVs will occur – whether it will move quickly, like the Internet or the radio, or whether it will resemble the slower adoption curve of the washing machine, considered a luxury item for many years. Radically new or different technologies may have a difficult time breaking through, not because of the merits of the technology itself, but because regulations, infrastructure, maintenance networks and user practices are aligned to an existing technology. This is certainly a major consideration in the case of EVs. The current automotive marketplace revolves primarily around gasoline-powered vehicles. In addition to automakers themselves, there is an entire aftermarket involved in manufacturing, distributing, retailing and installing vehicle parts, equipment and accessories for gasoline-powered vehicles. This is not to say, however, that emerging technologies are unable to overcome these challenges.

While technological advances will go a long way to overcoming barriers to EV adoption, these alone may not be enough to appeal to the broader market. EVs will not succeed in the market if perceptions about their usefulness are not positive. For example, Consumer Reports, an independent organization that tests consumer products and services, awarded the Tesla Model S a rating of 99 out of 100 in 2013. This matches the best score earned by any vehicle, not just an EV, in the history of Consumer Reports. Yet many were quick to point out that, because of the lack of infrastructure to support its use, particularly infrastructure for fast charging, the Model S is hardly just one point shy of perfect.

The electricity distribution system's ability to respond to the power demand for EV charging will play a critical role in the adoption of the technology, particularly in the broader market.

The electricity distribution system's ability to respond to the power demand for EV charging will play a critical role in the adoption of the technology, particularly in the broader market. One of the key factors affecting the ability of the electricity distribution system to accommodate EV-related loading is the capacity of the vehicle's on-board charger. The charging process for an EV involves components both on and off the vehicle. Electricity delivered through an external device such as a household outlet or an EV charging station is converted to battery power by a small charger on board the vehicle. The charging level determines the rate at which electrical energy is drawn when an EV battery is being charged. Most of the first wave of mass-produced EVs on the market contain an on-board charger rated at 3.3 kW or 6.6 kW when charging at 240 V – similar to the power delivered through a clothes dryer receptacle. This is known as Level 2 charging. Most EVs can also be charged using a standard 120 V household outlet; this is known as Level 1 charging. A vehicle charging at Level 1 draws power at a lower rate, between 1.0 kW and 1.9 kW – similar to a typical hair dryer.

With advances in technology, some newer EVs have significantly more powerful on-board chargers – in some models, rated up to 20 kW. Some models have the capacity to use Level 3 charging (also known as DC fast charging). Level 3 chargers use greater amounts of power, operating at up to 500 V, to provide a fast charge – in minutes rather than hours. The amount of power required to supply a fast charge is so great that, without significant upgrades, very few homes would be able to support a Level 3 charging station; as such, Level 3 charging is primarily found at public charging stations. Because these fast chargers can address concerns about the limiting range of EVs ("range anxiety") and the amount of time required to charge the vehicle away from home, implementing them will likely be a key factor influencing EV adoption and will require careful planning on the part of the LDC.

The Potential Impacts of EV Use in London

Current patterns of EV charging in the London Hydro service area do not represent a risk to the utility's capacity to maintain a safe and reliable supply of power to all its customers. Nor is the demand for power to charge EVs at home expected, in the short term, to exceed the rated capacities of London Hydro's current infrastructure assets at the neighbourhood level. However, the prevailing trend in new EV technology is towards larger batteries and faster charging, as automakers respond to market demand for greater driving range, convenience and overall performance. The compounding effect of these factors means that London Hydro will have to continue to monitor the potential effects of EV charging on the electricity distribution system.

Current patterns of EV charging in the London Hydro service area do not represent a risk to the utility's capacity to maintain a safe and reliable supply of power to all its customers.

This report shows that, if just a handful of neighbouring households charge EVs with greater on-board charger ratings at the same time during periods of peak demand, the electricity infrastructure on some streets could be overloaded; however, encouraging charging when demand for power is otherwise at its lowest would allow greater numbers of EVs to charge without necessitating changes to the existing electricity distribution assets. Additional transformer and secondary distribution system capacity may eventually be necessary to accommodate greater numbers of EVs charging; taking EV use into consideration in the process of scheduled upgrades will help mitigate risks.

As the EV market evolves, it makes sense for London Hydro to continue to monitor the potential effects of EV charging, using information systems already in place. Such an EV strategy is consistent with the mandate of London Hydro to ensure a safe and reliable supply of power for its customers and with its long-standing commitment to routinely assessing the capacity of the electricity distribution system on an ongoing basis, identifying and addressing issues before they become a problem.

Enabling Electric Vehicle Use in London – A Strategy to Manage the Risks and Optimize the Benefits

By developing a strategy for enabling EV use in its service area, London Hydro can enhance its current organizational capacities to be responsive to consumers' basic needs and to the evolving state of EV technology. Such a strategy will also allow London Hydro to leverage opportunities associated with EV use and to be progressive in promoting EV technology within the current regulatory framework, informing customers' decisions about becoming EV drivers and supporting their transition. Flexibility will be key to ensuring the success of this strategy for enabling EV adoption as it evolves within the broader electricity utility landscape of smart grid technologies, distributed generation and demand response programming.

Key stakeholders internal and external to London Hydro must be engaged in the development of this strategy because the successful deployment of EV technology in London depends on actions and decisions taken by a range of individuals and organizations. Stakeholders internal to London Hydro include its Executive Management Team as well as those responsible for asset management, communications, customer service, and conservation and demand management. Stakeholders external to London Hydro include

- the Ontario Energy Board (OEB)
- the Independent Electricity System Operator (IESO)
- the Ontario Ministry of Transportation
- the Ontario Ministry of Energy
- London Hydro customers, including current and future EV owners and users
- the City of London, including planners and developers
- academia, including local colleges and universities
- Electric vehicle supply equipment (EVSE) providers

A strategic approach to enabling successful EV use in London can be built on the following recommendations, drawn from the EMAP market research and electricity distribution system assessment:

1 Enhance utility responsiveness to evolving patterns of EV charging.

- Monitor the development of the EV market in the London Hydro service area. This means keeping apprised of changes in EV products and technologies, operating standards, regulations and general market adoption; requesting notification from automotive dealerships or the provincial government when an EV is sold within the service area could also be helpful. Ongoing analysis of load profile data is also an important element in responding to the evolving impacts of EV charging on the local distribution system.
- Promote and facilitate EV charging habits that reduce daily peaks in demand for power and that optimize use of the distribution system's existing assets. The EMAP assessment shows that EV charging has the potential to affect the electricity distribution system if early adopters charge their vehicles during periods of peak demand. Encouraging EV charging during off-peak hours will help to ensure that EVs do not add to peak demand on the distribution system.
- Consider implementing a program through which London Hydro customers can volunteer information about their purchase of EV technology (e.g., vehicle model, charging services) or their intention to purchase an EV. With this information, London Hydro can conduct predictive infrastructure assessments to determine if service upgrades will be required to maintain quality of service. This will also ensure that London Hydro is aware of any residential service upgrades that could be required to accommodate the installation of Level 2 or 3 residential charging stations.

Key stakeholders internal and external to London Hydro must be engaged in the development of this strategy because the successful deployment of EV technology in London depends on actions and decisions taken by a range of individuals and organizations.

- Take into consideration the impacts of EV charging when infrastructure design criteria are being developed to ensure that they do not present barriers to EV use. Accounting for anticipated levels of EV uptake in the course of scheduled asset replacement will ensure sufficient capacity for EV charging without compromising the reliability of the power supply. Investigate the effects of EV charging on the electricity distribution system when the load is actively managed (e.g., by way of smart grid automation or user-programmable charging parameters, such as level of charge or timing of charge). Building on the analysis in the EMAP grid assessment, determine the degree to which greater levels of demand for charging services could be accommodated if the timing and duration of EV charging were actively managed.

2 Build partnerships to address barriers and leverage opportunities for EV deployment, consistent with the needs of early adopters.

- Foster dialogue among electricity utilities on best practices related to EV technology. As the EV market continues to evolve, utilities across Canada will face some common challenges and opportunities related to EV use within their service areas. Shared strategies and lessons learned can contribute to better understanding and, in turn, to enhanced opportunities to successfully enable and promote EV use across the country.
- Collaborate with other organizations with a stake in the future of EV technology (e.g., the London Electric Vehicle Acceleration Group, the City of London) to actively promote and encourage EV use within the current regulatory framework.

3 Educate customers about EV technology.

- Create targeted communications to address the concerns identified in the analysis of the early adopter community, as summarized in this report. The EMAP study shows that London Hydro is considered a trusted source of information about EV technology and a trusted provider of services for EV charging. This provides a solid foundation for effective communication with customers – both early adopters and the general public.
- Actively promote and encourage EV use within the service area by building an understanding of the implications of EV technology, particularly from a social perspective. This could include educating customers about optimal charging behaviours and how they can help to maintain the reliability of existing distribution system assets, thereby helping to keep rates low.
- Equip London Hydro's communications and customer service groups with the necessary information, including sample scripting where appropriate, to respond to general customer inquiries about

EV technology. This should include information about electrical safety in relation to EV deployment (e.g., the importance of hiring a qualified electrical contractor and complying with inspection requirements when installing residential charging stations).

- Provide information and links to resources related to EV charging on the London Hydro website. This could include tips for deciding whether an EV might be a good fit, the location of public charging infrastructure within the service area, or details about residential charging station installation. For example, installation costs may be higher for residential charging stations capable of drawing power at more than 7 kW than for those that provide a charge at a lower rate (e.g., 3.3 kW or 6.6 kW) because the household service may need to be upgraded to support higher charging levels. Directing customers to London Hydro for information about installing a charging station will help them to make more informed decisions and avoid unnecessary costs.
- Work with automotive dealers and their associations to explore opportunities to respond to customers' questions about EV technology and to provide them with the information they need to make an informed decision about driving electric. The EMAP study indicates that the EV option was mentioned to only a few potential early adopters who had recently visited a dealership. This points to an opportunity to provide information at the point of purchase to actively support EV deployment.
- Identify opportunities to educate businesses and workplaces about EV charging so that they can directly support EV deployment in London. The EMAP study indicates that an overwhelming majority of early adopters currently park in employer-provided lots but that employers are not, on the whole, well informed about how appropriate charging services are installed, the costs involved in doing so, and the potential economic opportunities and benefits associated with offering workplace and/or public charging. Making such information available to employers can help to encourage them to support EV owners.

Purpose of Surveying the City of London

Understanding the perceptions of EVs – both positive and negative – among the early adopter community in London will make it possible to develop effective and targeted information and awareness campaigns and to provide a framework to facilitate local policy implementation. It is important to understand how EVs can be used in order to ensure that their deployment in communities is a successful experience for owners, and that the range of potential benefits associated with the technology can be fully realized. Market research can generate critical information on the needs and views of the early adopter population, using demographic and psychographic analyses to understand the barriers that must be addressed to encourage the uptake of EV technology.

Methodology

The market research process involved two separate but related sets of investigations:

- secondary research to identify the geographic distribution of potential early adopters of EV technology
- primary research to characterize early adopters and identify potential opportunities and barriers to EV adoption

The specific process, outputs and assumptions made in the development and application of the research are described below.

Secondary Research to Identify the Geographic Distribution of Potential Early Adopters

The secondary research sought to identify the behavioural and attitudinal characteristics of likely early adopters of EV technology and to map the neighbourhoods in which they may tend to cluster. This research was the basis for the primary research that followed, allowing for a more efficient and targeted household survey of the characteristics and preferences of likely early adopters of EV technology.

The secondary research was undertaken in collaboration with Environics Analytics, using its proprietary PRIZM$_{c2}$ segmentation system database. The PRIZM$_{c2}$ system classifies every neighbourhood and postal code throughout Canada into one of 66 segments based on the most important drivers of consumer behaviour, including demographics, lifestyles and social values. It assumes that neighbourhoods that are classified similarly have comparable demographic, behavioural and attitudinal characteristics regardless of where they are located. As such, the PRIZM$_{c2}$ segments are an effective means of estimating behaviours and attitudes at a very local level, based on data collected at a very high level.

For the purpose of creating a profile of a potential early adopter of EV technology, data from a number of different surveys as well as national and regional vehicle purchase information were linked to the PRIZM$_{c2}$ segments. These databases included the Environics Analytics DemoStats database, the Environics Research Group Social Values nationwide survey, and IHS Automotive's New Vehicle Registrations (NVR) and Total Vehicles in Operation (TVIO) databases.

Because EVs currently account for only a small portion of total vehicles in the marketplace, EV purchase data in surveys and databases are limited. Therefore, the following key variables were selected as indicators of the propensity to purchase an EV:

- demographic characteristics
- social values
- vehicle purchase data

These variables were developed using analogous products and services, appropriate demographics and relevant social values. The key variables are described in further detail below.

KEY VARIABLES USED AS INDICATORS OF THE PROPENSITY TO PURCHASE AN ELECTRIC VEHICLE

Demographic Characteristics

Early adopters were assumed to be those who met a set of demographic criteria based on an understanding of the current characteristics of the EV market and technology. These demographic criteria are as follows:

- **Average household size of not less than two people:** Because of the potentially limiting vehicle range, it was assumed that early adopters of EV technology would at least initially see the vehicle as a second, rather than the sole, household vehicle. While EVs easily suit urban transportation needs, longer trips could require a second, conventional gasoline-powered or hybrid vehicle. If the EV were bought as a second vehicle, it was assumed that the current purchase price of an EV would be prohibitive for such purposes for a single household resident.
- **Smaller average household size:** Many EV models currently on the market tend to be small and, therefore, more suitable for small households than for large families. However, consideration was given to the increasing size and range of EV models being introduced as the market evolves.
- **Greater than average household income:** Based on the high purchase price of EVs at the time the research was done, it was assumed that the household income of early adopters would be high compared to the general population in London. Special consideration was, therefore, given to the types of neighbourhoods with high disposable incomes.

Social Values

Potential early adopters of EV technology were assumed to be those who exhibited one or more of the following three attitudes:

- **Ecological lifestyle:** This indicator characterizes those individuals who value the integration of environmental concerns with purchasing decisions. Because of the potential environmental benefits and emissions reductions promised by EV technology, early adopters were assumed to be environmentally conscious.
- **Enthusiasm for technology:** This indicator reflects a favourable bias towards technology. People with an enthusiasm for technology tend to believe that it is the best tool for adapting and responding to the demands of daily life. Because EVs are not yet part of the mainstream marketplace, early adopters of EVs were assumed to have an enthusiasm for technology.

- **Consumptivity:** This indicator represents an enthusiasm for purchasing products or services in an area of particular interest (e.g., music, electronics) about which consumers make an effort to stay informed. Because information about EVs is not yet widely available in the mainstream media, particularly in Canada where the market is still small, it was assumed that early adopters of the technology would have to be particularly enthusiastic or have made an effort to become informed about the topic.

Vehicle Purchase Data

For the purposes of the market research, EV purchase data, including both new vehicle registrations between January 2012 and June 2013 and total vehicles in operation in 2012, were used to identify early adopters of EV technology. Because EV purchases are low, potential early adopters of EV technology were assumed to share psychographic and demographic characteristics with early adopters of hybrid vehicle technology. Accordingly, hybrid vehicle purchases for the same periods were also used to help estimate potential EV demand.

SECONDARY RESEARCH RESULTS

The variables identified as indicators of the propensity to purchase an EV were used to create profiles that were compared with the PRIZM$_{c2}$ system to identify a set of early adopter target segments. This section documents the findings from the secondary research, including a description of the target segments and their distribution within the City of London.

Target Segments

Eight psychographic segments of the London population were identified based on the selected demographics, social values and vehicle purchasing data. These segments include the types of individuals and households considered the most likely to be early adopters of EV technology in London.

The following are the eight segments selected:

Cosmopolitan Elite: This group represents Canada's wealthiest people, including new-money entrepreneurs and heirs to old-money fortunes. The Cosmopolitan Elite are urban, middle-aged families and older couples. With household incomes five times the national average, this segment is concentrated in only a handful of established neighbourhoods throughout the country.

Urbane Villagers: Located in Canada's largest urban centres, this segment is a prosperous world of stately homes and high-end cars, charity auctions and golf club memberships. The nation's second wealthiest segment, it is characterized by married couples with university degrees and university-aged children, and includes a significant percentage of European, Asian and Middle Eastern immigrants.

Suburban Gentry: This segment is made up of Canada's up-and-coming business class, with a high percentage of managers, scientists, government workers, and other professionals. Suburban Gentry residents rank near the top for operating a small business, owning business software and taking business trips. They include dual-income couples with university degrees and large families, are big spenders, particularly on entertainment, and take pride in their healthy lifestyle.

Winner's Circle: This segment is made up of large families living in bedroom communities and a few metropolitan areas in Canada. The average household income for this group is high and, while they express concerns about saving enough money for the future, they do not mind spending. Winner's Circle residents live in newer homes surrounded by recreational parks, ball fields, golf courses and malls filled with big-box stores.

Money & Brains: The residents in this segment have high incomes, advanced degrees and sophisticated tastes. Many of them are empty nesters or married couples with university-aged children, who live in older, fashionable homes in both urban and suburban neighbourhoods.

Pets & PCs: Scattered around Canada's larger cities, this group is made up of younger, multi-ethnic families with pre-school-aged children. Residing primarily in single-family homes and row house subdivisions, Pets & PCs lead active, child-centred lives, including participation in team sports and visiting kid-friendly destinations.

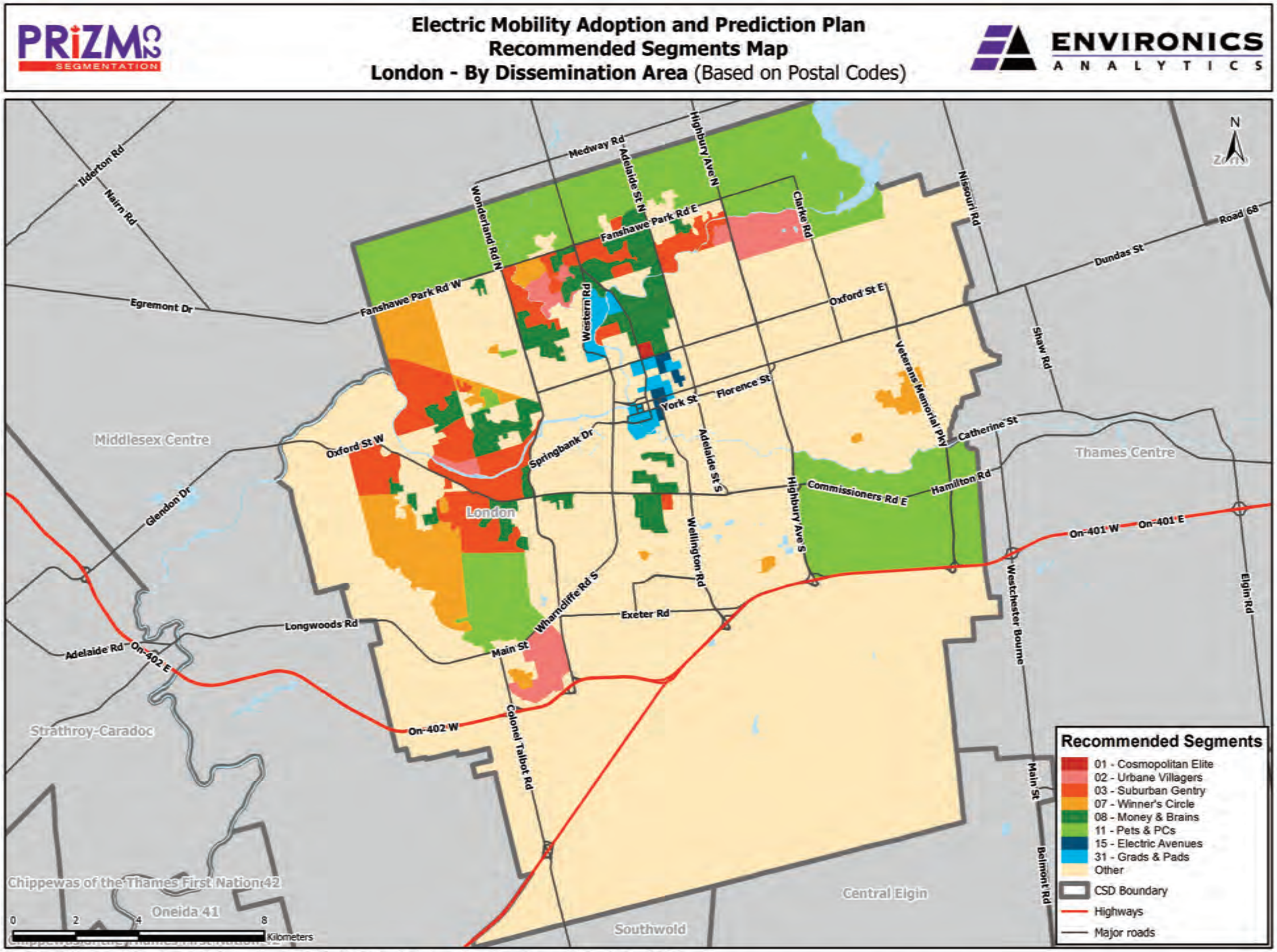
Electric Avenues: This group represents young singles and couples pursuing lively urban lifestyles. Concentrated in Canada's largest urban centres, these older, crowded neighbourhoods are known as havens for university graduates who rent apartments, have mid-level jobs and enjoy active leisure lives. While residents here have above-average household incomes, their spending power appears even greater because many of these households are childless.

Grads & Pads: This segment is made up of young, ethnically diverse city dwellers living near universities. Grads & Pads includes well-educated singles, couples, students, recent graduates, professionals and service workers just entering the workforce. They enjoy keeping active and are also politically active, working for social causes and volunteering for political parties that support their liberal views.

Geographic Distribution

A map was created, indicating the geographic distribution of each of the eight target segments within the City of London, based on postal codes (see Figure 2). Each area identified on the neighbourhood map represents a postal code area of potential early adopters, providing a visual representation of where they may be clustered throughout the city (the size of each area is determined by the boundaries of the postal code and is not a representation of the concentration of potential early adopters). These areas became the focus of the primary research described below.

Figure 2: Distribution of Target Segments in the City of London



Note: CSD – Census subdivision.

Primary Research to Validate and Characterize Early Adopter Neighbourhoods

In addition to estimating the demand for EVs in the London area using $PRIZM_{c2}$-based tools, the secondary research informed the primary research that followed. A questionnaire was designed for use in a household telephone survey conducted by Environics Research Group. The survey was conducted in key locations containing high proportions of segments with behavioural and attitudinal characteristics linked to the early adoption of EV technology. A total of 750 London residents participated in the survey, which took place between January 30, 2014 and February 15, 2014 and averaged approximately 16 minutes in length. The use of a telephone survey rather than an online survey allowed for a targeted focus on residents in the geographic areas identified; it would have been difficult to screen for this online. In addition, the telephone survey allowed for a greater opportunity to test scenarios with survey respondents to build an understanding of how best to position EVs in a deployment strategy.

Respondents were screened to ensure that they were licensed drivers, aged 18 or over, and involved in household vehicle purchase decisions. They also had to have bought or leased a 2010 or newer vehicle within the past three years or be intending to buy or lease a late-model vehicle in the following three years. Respondents who met these criteria were deemed to have an understanding of or experience with the factors contributing to purchasing decisions for a new vehicle.

The household survey was designed to gain insight into motivations for and interest in EV use, the personal mobility patterns of the respondents, the expectations of EV technology, and the barriers to address and opportunities to leverage in relation to EV use. The survey was divided into the following four sections:

- vehicle ownership and use
- awareness and perceptions of EVs
- charging capabilities
- market segmentation and respondent profile

KEY FINDINGS FROM THE PRIMARY RESEARCH

This section presents key findings and insights from the household telephone survey. It begins with a profile of potential early adopters and is followed by a discussion of their awareness and perceptions of EV technology and their expectations for residential charging.

Profile of the Potential Early Adopter

Demographic Profile

Potential early adopters are older, better educated and more affluent than the general population. The majority live in detached single-family homes.

Potential early adopters are considerably more likely to be over the age of 45 than the general adult population in London. They are better educated, with six in ten of those surveyed holding a university degree (bachelor or post-graduate), compared to only 25 per cent of the general population. Potential early adopters are also more than twice as likely as the average city resident to have a household income of $150,000 or more, and a strong majority (78 per cent) live in detached single-family homes and have no children currently living with them.

Figure 3: Age and Household Income

Age	Survey sample, %	London population, %
Under 30	3	23
30 - 44	19	24
45 - 59	34	28
60+	45	26

Household income	Survey sample, %*	London population, %*
Under $60K	20	51
$60 to <$100K	30	25
$100 to <$150K	24	15
$150K+	26	9

*Statistics Canada National Household Survey 2011

Vehicle Purchasing Preferences

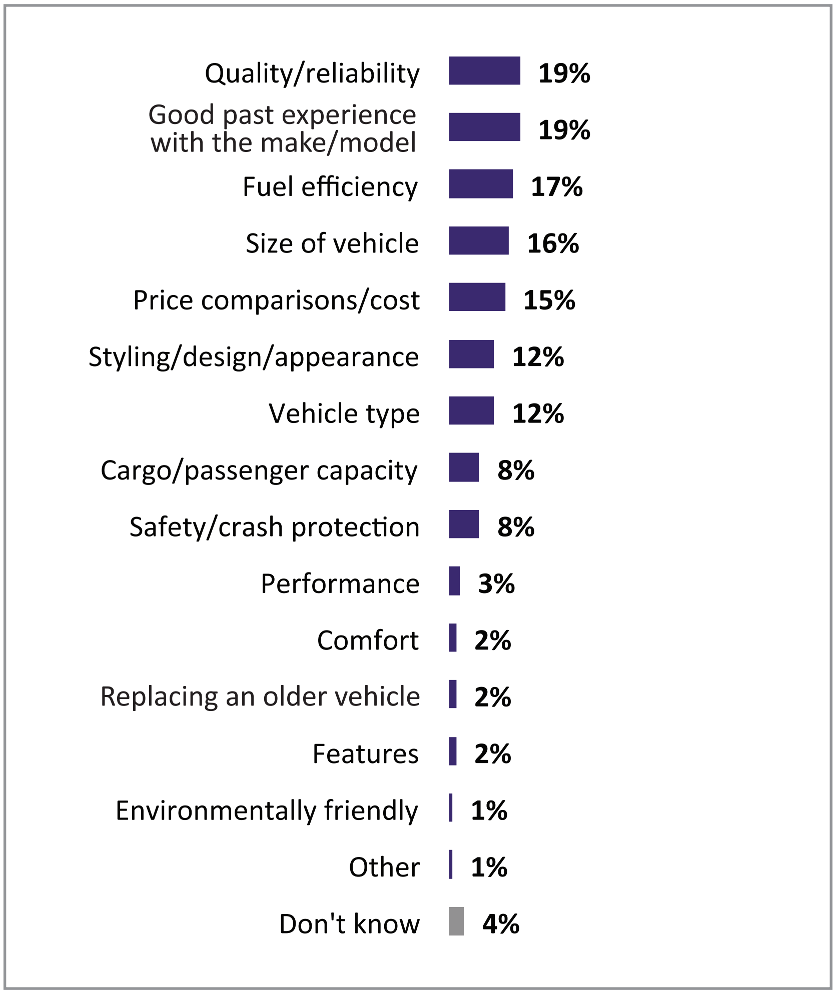
Personal experience with an EV is linked to greater interest in owning one.

Of the 750 participants in the household telephone survey, 7 per cent indicated that they currently own a hybrid vehicle (not a plug-in), and one person reported owning a plug-in hybrid vehicle. Among potential early adopters who do not currently own an EV, personal experience with EVs is limited. Only 4 per cent have driven one, while one in ten has been a passenger, and fewer than one in five reported knowing someone who drives one. A strong majority (eight in ten) have not had any of these experiences with EVs. One in four of those who later indicated that they would either definitely or likely consider the purchase of an EV in the near future have some previous personal experience with one. Personal experience and exposure to EVs is likely to increase and, as it does, it is expected that interest in purchasing them will likely also increase.

Reliability and a positive past experience are the main considerations for potential early adopters when they are purchasing a vehicle.

Reliability and a positive past experience were the top responses from recent buyers when they were asked why they chose their current vehicle. Fuel efficiency, the size of the vehicle and purchase price were also important considerations.

Figure 4: Top Reasons for Vehicle Choice

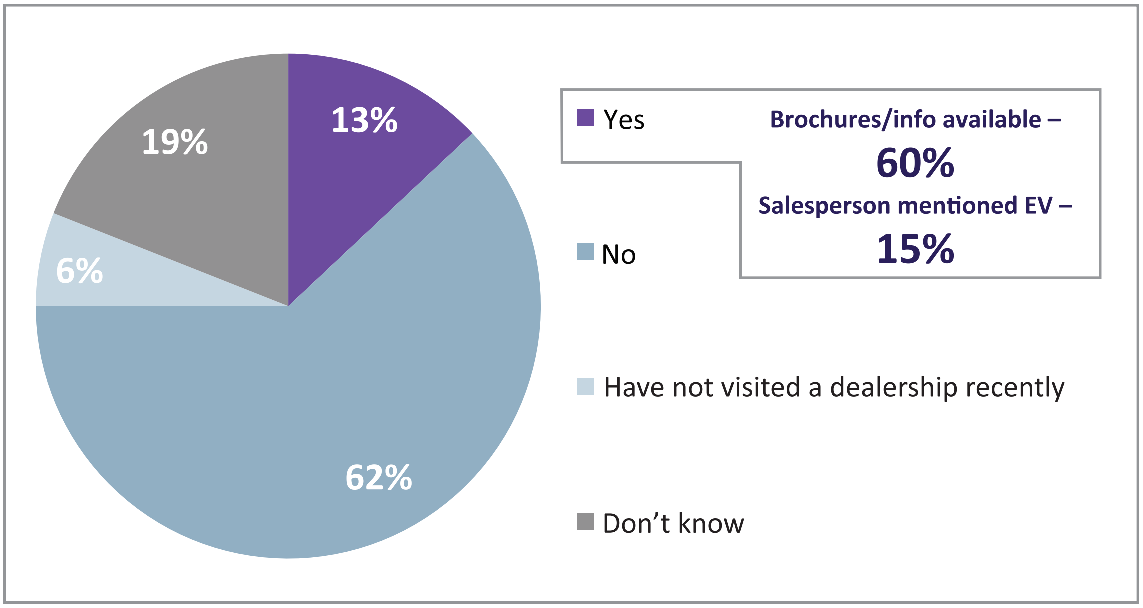


Subsample: Recent purchasers (N=577)

Few potential early adopters reported an EV being suggested as a purchase option during their most recent visit to a dealership.

Potential early adopters were asked if, on their most recent visit to a dealership, there were any EVs available for purchase or lease. About one in ten (13 per cent) indicated that there was an EV available while six in ten said that there were none. Only 15 per cent of those who had recently visited a dealership indicated that the salesperson had suggested an EV as a potential purchase or lease option. Sixty per cent of those who responded that there was an EV available for purchase or lease indicated that brochures or other information were available at the dealership.

Figure 5: Electric Vehicle Availability During Most Recent Visit to a Dealership

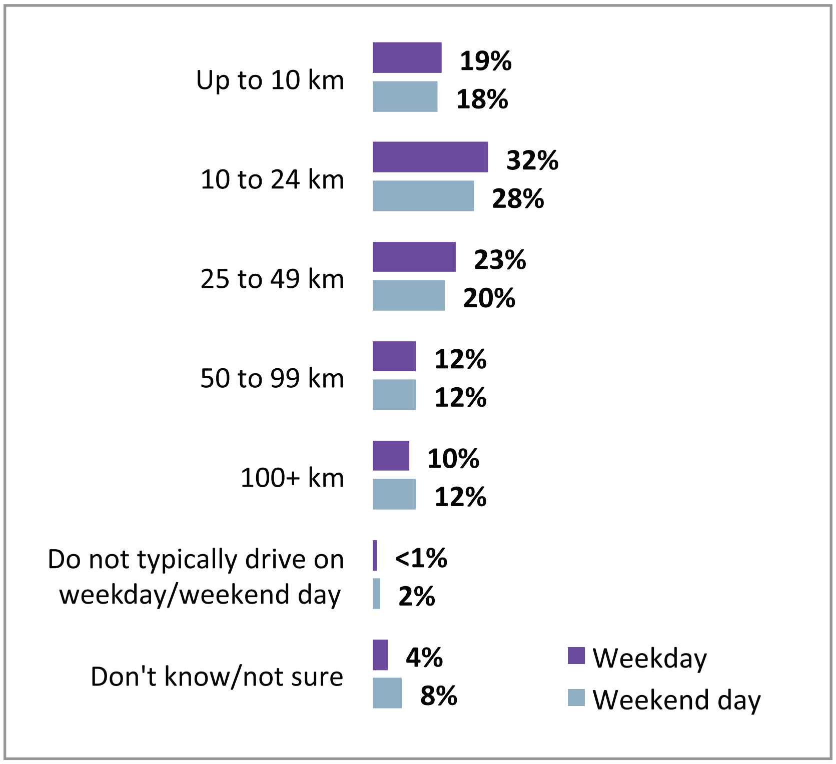


Personal Mobility Patterns

About half of all potential early adopters use their vehicles every day.

Just over half of potential early adopters (53 per cent) indicated that they use their vehicles seven days a week. Close to half (45 per cent) of potential early adopters travel more than 25 kilometres on a typical weekday, while 46 per cent drive the same distance on a typical weekend day. Driving every day increases proportionally with the number of vehicles in the household and is highest among those who drive 50 kilometres or more on a typical weekday. It is also higher among those with a child in the home (62 per cent). Driving seven days a week, however, does not appear to have any relationship to the level of interest in purchasing an EV in the next couple of years.

Figure 6: Kilometres/Day Typically Driven



Half of potential early adopters are considered vehicle commuters.

Around half of potential early adopters (49 per cent) said that there is a specific location that they typically drive to at least three days per week and where they leave their vehicle for three or more hours (the selected proxy for vehicle commuting). Vehicle commuting increases with household income and is highest among those with incomes of $150,000 or more.

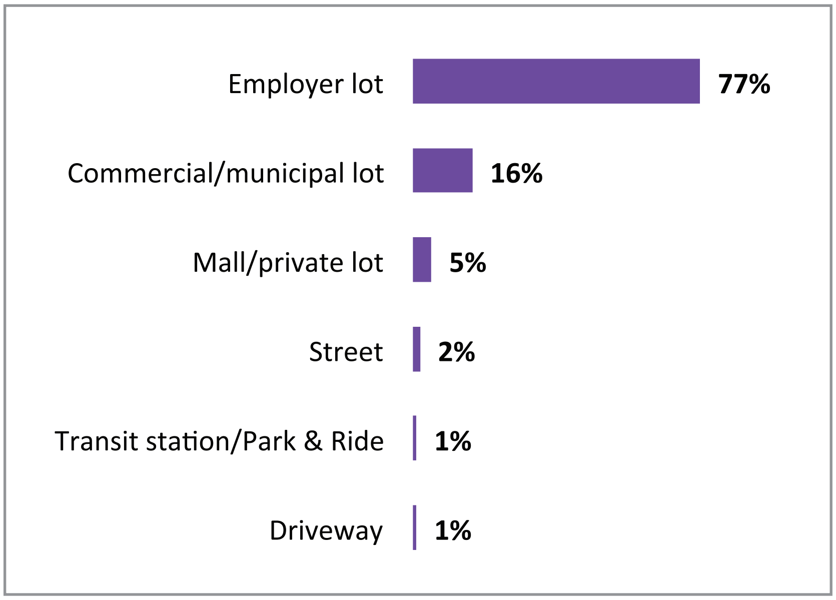
The majority of vehicle commuters leave home between 7 a.m. and 9 a.m. and return home between 2 p.m. and 7 p.m.

Most vehicle commuters described a typical workday as one on which they leave home between 7 a.m. and 9 a.m. (58 per cent) and return home between 2 p.m. and 5 p.m. (38 per cent) or between 5 p.m. and 7 p.m. (36 per cent). Vehicle commuters who indicated that they typically drive less than 25 kilometres on a weekday were more likely to say that they return home between 2 p.m. and 5 p.m. Vehicle commuters were also asked to indicate how many hours they park at the location where they typically leave their vehicle. The most common response was eight hours (39 per cent). Close to four in ten spend seven hours or less parked at this location, while two in ten spend nine hours or more.

The majority of vehicle commuters park in an employer-provided lot.

When asked which of several options describes their typical parking arrangements at the location where they park at least three days per week, the majority (77 per cent) of vehicle commuters indicated that they park in an employer-provided lot.

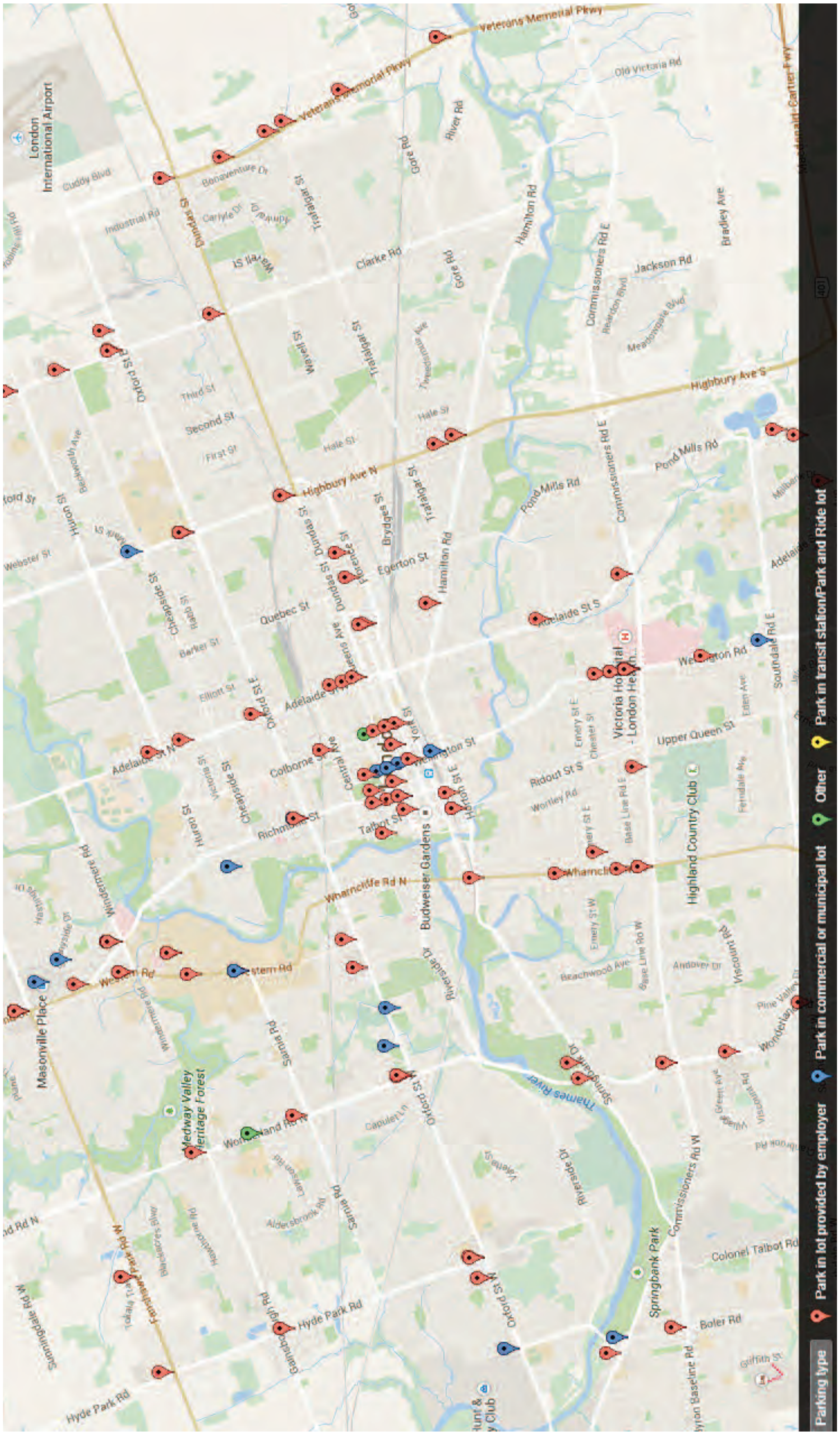
Figure 7: Type of Parking at Specific Location



Subsample: Those who leave their vehicle at a specific location at least 3 days per week for at least 3 hours (N=369)

When asked to name the major intersection nearest the location where they typically leave their vehicle, the majority of vehicle commuters reported that they remain in or around London (see Figure 8).

Figure 8: Vehicle Commuter Parking Locations in London by Lot Type



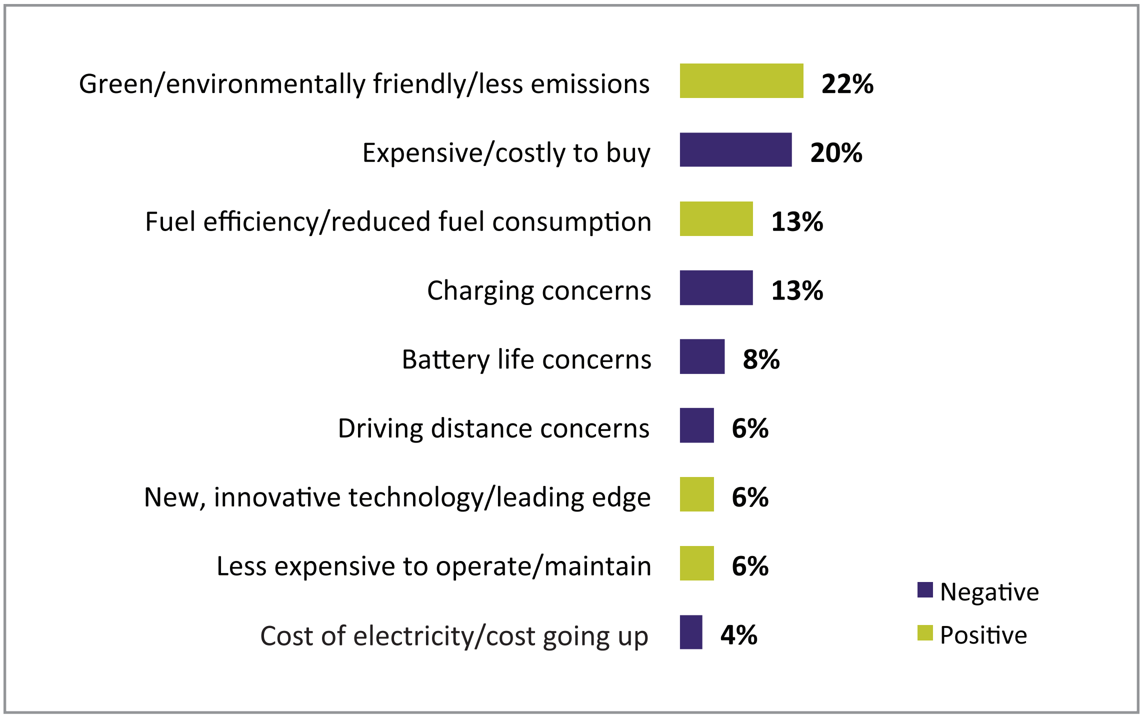
Awareness and Perceptions of Electric Vehicles

Familiarity with Electric Vehicles

Potential early adopter impressions of EVs reflect both barriers and opportunities.

When asked to provide their top-of-mind impressions of EVs, potential early adopters gave a range of responses, covering both the advantages and the disadvantages. The most common response was a positive one – the green or environmentally friendly potential of the vehicle – but about half made some negative mention. The most common negative responses were related to purchase price or range anxiety (battery life, charging concerns or the potentially limiting range of the vehicle). There were more negative mentions from potential early adopters who would likely or definitely not consider an EV than from those who would likely or definitely consider one.

Figure 9: Most Mentioned Top-of-Mind Impressions of Electric Vehicles



Note: adds up to more than 100% due to multiple mentions

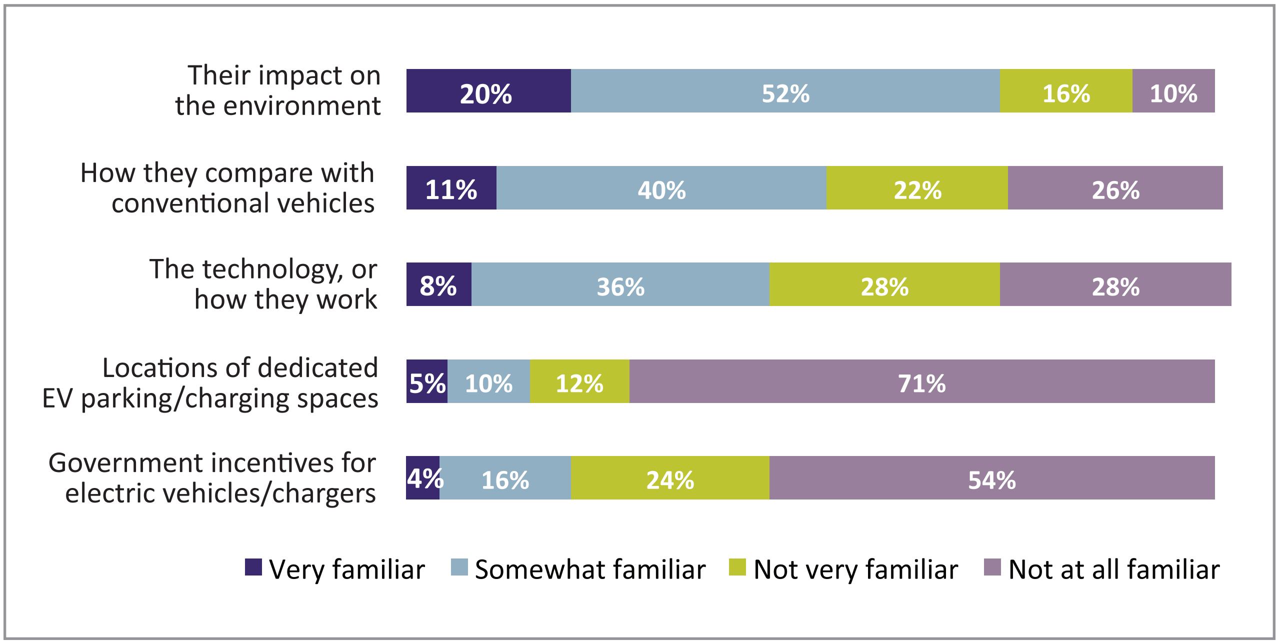
The majority of potential early adopters are most familiar with the environmental impact of EVs.

All potential early adopters were asked to indicate their level of familiarity with five specific aspects of EVs:

- their impact on the environment
- how they compare with conventional gasoline-powered vehicles
- the technology, or how EVs work
- government incentives for purchasing EVs or installing home charging stations
- the location of dedicated EV parking/charging spaces in London

While few respondents claimed to be very familiar with any aspect of EVs, seven in ten said that they were at least somewhat familiar with their environmental impact. Half expressed the same level of familiarity with how EVs compare with conventional vehicles, and four in ten indicated some familiarity with the technology, or how EVs work. Awareness of current government incentives was low, with 71 per cent of respondents indicating that they were not at all familiar with incentives for purchasing an EV or installing a home charging station. A strong majority of potential early adopters indicated that they were not at all familiar with the location of dedicated EV parking/charging spaces in London. Strong familiarity with any of the five aspects of EVs was linked to a definite willingness to consider buying an EV.

Figure 10: Familiarity with Specific Aspects of Electric Vehicles



Likelihood of Considering an Electric Vehicle

One-third of potential early adopters would consider purchasing an EV in the next couple of years.

Only 30 per cent of potential early adopters said that they would likely (25 per cent) or definitely (5 per cent) consider an EV if they were purchasing or leasing a vehicle in the next couple of years. A majority of 67 per cent felt that they would likely not or definitely not consider an EV within the next two years. Age is an important factor in the potential purchase of an EV, with the likelihood of considering one lowest among those aged 60 and older (21 per cent versus 39 per cent of younger drivers). As previously noted, some experience with an EV is slightly higher among those who would likely or definitely consider purchasing one in the next couple of years.

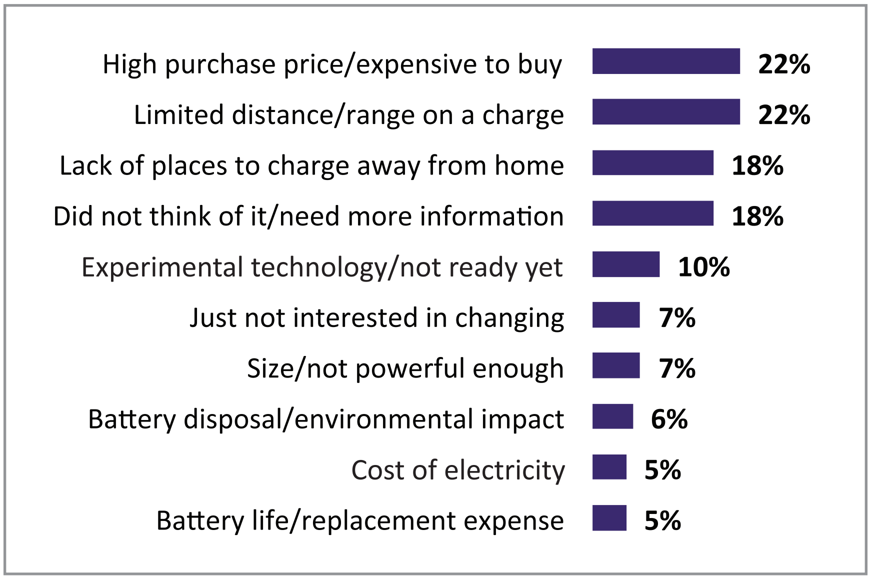
Perceived Barriers and Opportunities

Potential environmental benefits are the most mentioned advantage of EVs. Purchase price and limited range are the most mentioned barriers.

Around two-thirds (62 per cent) of those who would likely or definitely consider purchasing an EV mention that the main advantages of the vehicle are the potential environmental benefits and the opportunity to reduce vehicle emissions. Thirty-four per cent mention not having to purchase gas, and 19 per cent note the cost savings related to vehicle maintenance. A smaller number report an interest in EVs as an emerging technology, the suitability of the vehicle for city driving or the quiet ride.

Two in ten of those who indicated that they would definitely not or likely not consider an EV felt that the most important reason for not doing so was the high purchase price of the vehicle. A further 22 per cent mentioned the potentially limiting range of the vehicle, and equal numbers (18 per cent) noted the lack of charging locations away from home and the need for more information on which to base a purchasing decision.

Figure 11: Top Reasons for Not Considering an Electric Vehicle



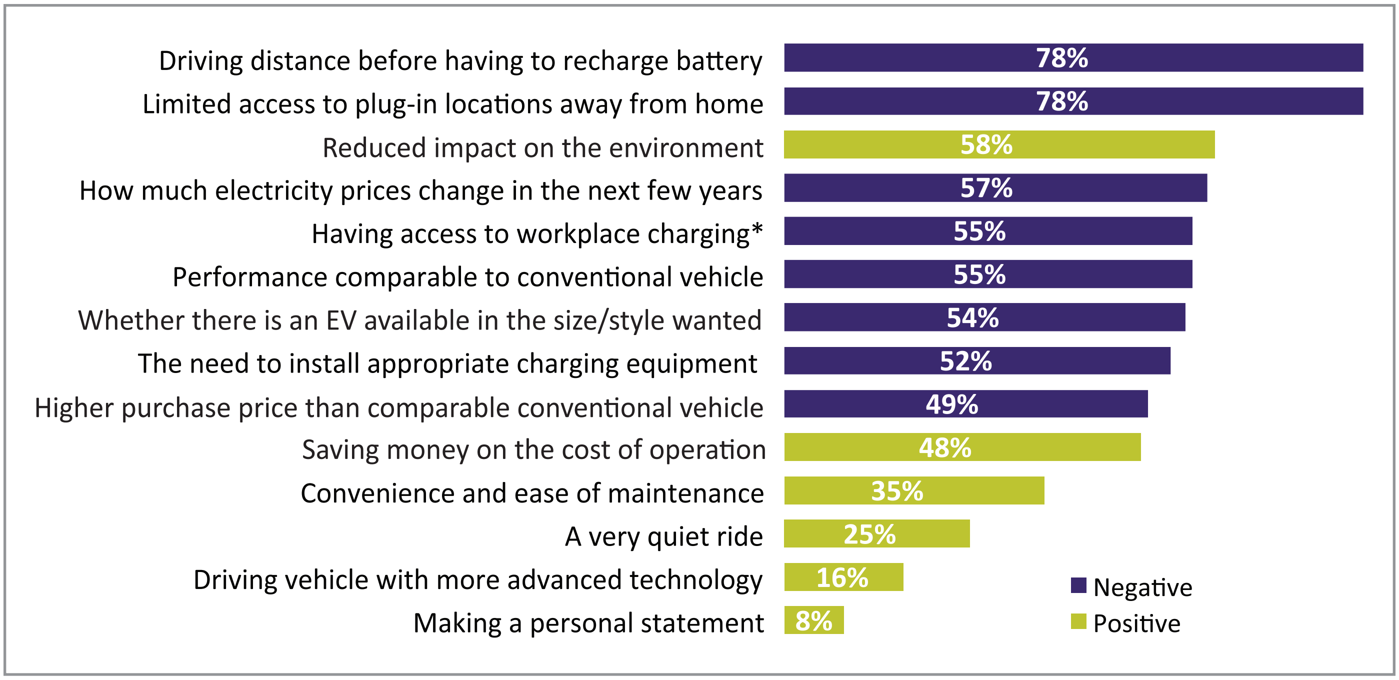
Subsample: Would definitely/likely consider an EV (N=500)

Charging concerns are the most important consideration in deciding whether to purchase an EV.

Those potential early adopters who would at least marginally consider purchasing an EV were asked to rank several positive and negative aspects of the vehicle in terms of their importance in the consideration of a future purchase or lease. The aspects rated as the most important once again reflect concerns related to range anxiety, including the distance that can be driven before the vehicle needs to be charged and the currently limited access to public charging stations. The potential for reduced impact on the environment as a result of driving an EV, future electricity costs, having access to workplace charging, overall performance compared to gasoline-powered vehicles, and available sizes or styles are of less importance than the concerns about range anxiety. It should be noted, however, that purchase price may end up being more of a deciding factor when an actual retail scenario is being considered.

Those who indicated that they would definitely or likely consider an EV were more likely than others to mention that the positive aspects would be important. However, those who would likely consider an EV were also just as likely as those who would likely not consider one to say that barriers related to range anxiety would be very important.

Figure 12: Electric Vehicle Aspects Considered *Very Important* in Purchase Decision



Subsample: Would definitely/likely/likely not consider an EV and do not own an EV (N=522)

*Asked of respondents who are commuters and who use employer-provided parking (N=224)

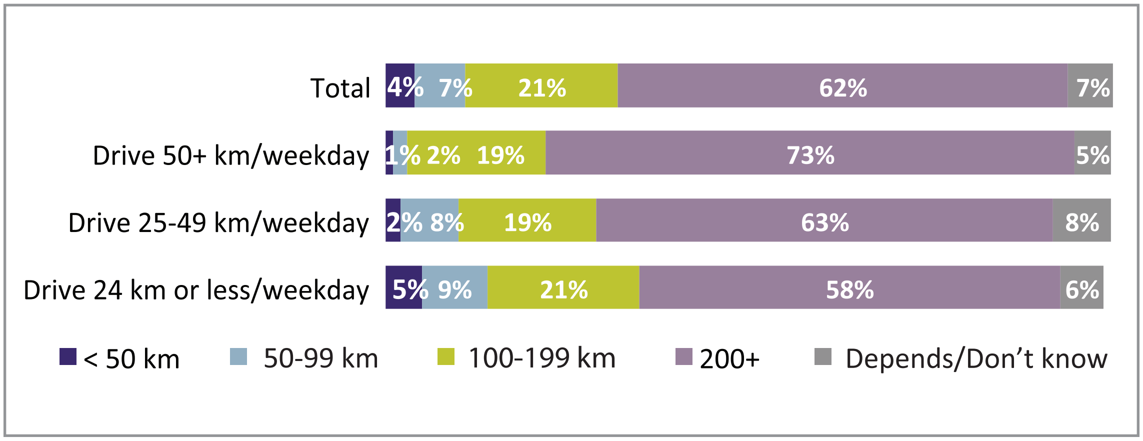
Charging Expectations

An EV would have to have a range of at least 200 kilometres on a single charge for most potential early adopters to feel comfortable.

Six in ten potential early adopters (62 per cent) said that an EV would have to be able to travel more than 200 kilometres on a single charge for them to feel comfortable that they would not get stuck somewhere without access to charging facilities. Less than one-quarter would be comfortable with a charge that lasted between 100 and 200 kilometres, and only one in ten would find a range of less than 100 kilometres acceptable.

Potential early adopters who drive less than 25 kilometres on a typical weekday were almost as likely as those driving longer distances to say that a 200 kilometre range would be required. This suggests that these drivers were thinking about a worst-case scenario or basing their expectations on the topping up of a gasoline-powered vehicle rather than on their actual typical personal mobility patterns.

Figure 13: Acceptable Distance for Travel on a Single Charge

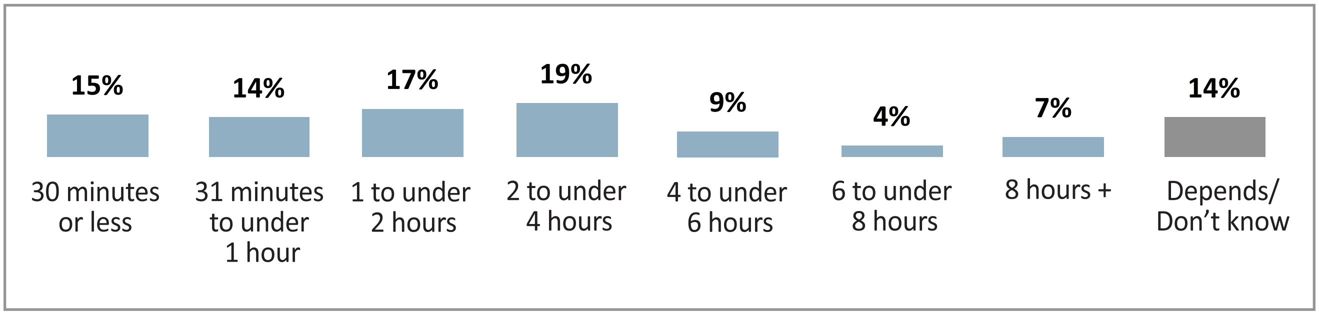


Subsample: Would definitely/likely/likely not consider an EV and do not own an EV (N=522)

The majority of those who would consider purchasing an EV think that it should take less than four hours to fully charge.

A range of opinions were expressed when those who would be at least marginally likely to consider an EV purchase in the next couple of years were asked what they felt would be an acceptable length of time to fully charge the vehicle. Two-thirds of potential early adopters think that it should take less than four hours to charge, with the most common response being between two and four hours, followed closely by one to two hours. About one-third of those who would consider purchasing an EV felt that it should take less than one hour for a full charge.

Figure 14: Acceptable Length of Time to Fully Charge an Electric Vehicle



Subsample: Would definitely/likely/likely not consider an EV and do not own an EV (N=522)

Access to faster home charging is considered very important.

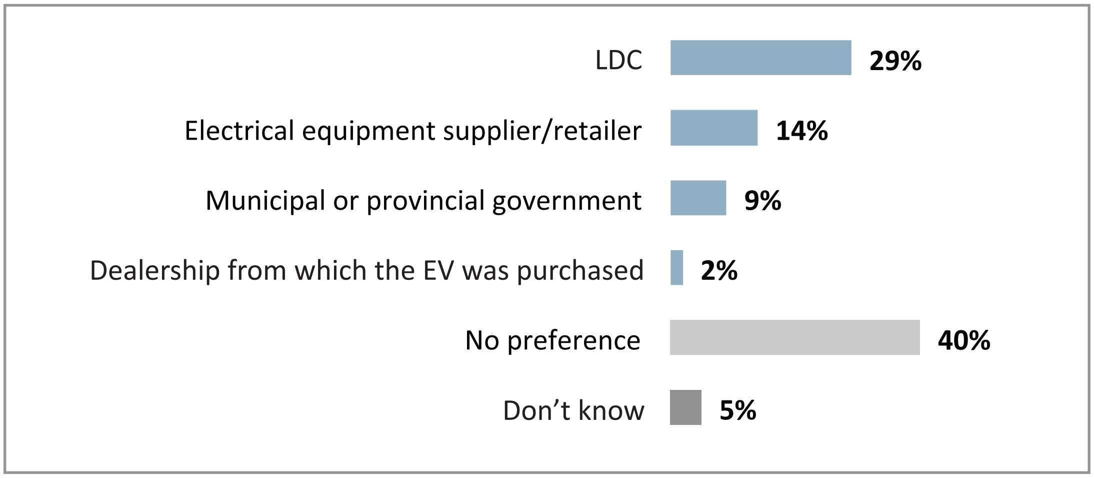
Potential early adopters understand that EVs need time to charge, unlike a gasoline-powered vehicle with a gas tank that can be filled quickly. However, more than half think that it should take less than four hours (similar to the length of time it takes to charge an iPod) to fully charge the vehicle. When told that, depending on how depleted the battery is, charging the vehicle could take 12 hours or more using a standard household outlet, an overwhelming majority said that it would be very (73 per cent) or somewhat (21 per cent) important to be able to charge faster – for example, with a more powerful Level 2 charger installed at home. This is consistent with two-thirds of those who would consider purchasing an EV indicating that an acceptable length of time to fully charge the vehicle would be less than four hours.

The number of respondents who said that faster charging would be very important increased proportionally with an increase in the distance driven on a typical weekday and was higher among vehicle commuters.

Three in ten potential early adopters would prefer the LDC to install and maintain a home charging station.

Those who said that it would be at least somewhat important to charge an EV faster were asked which of four potential service providers they would prefer to have install and maintain a Level 2 charging station at their home. A majority of four in ten said that they have no particular preference, while 29 per cent would prefer this to be done by the LDC. An electrical equipment supplier/retailer was mentioned by 14 per cent, and 9 per cent would prefer the government to act as the primary service provider. Only 2 per cent indicated a preference for the dealership from which they purchased their EV.

Figure 15: Preferred Service Provider for Installing and Maintaining an At-Home Charging Station

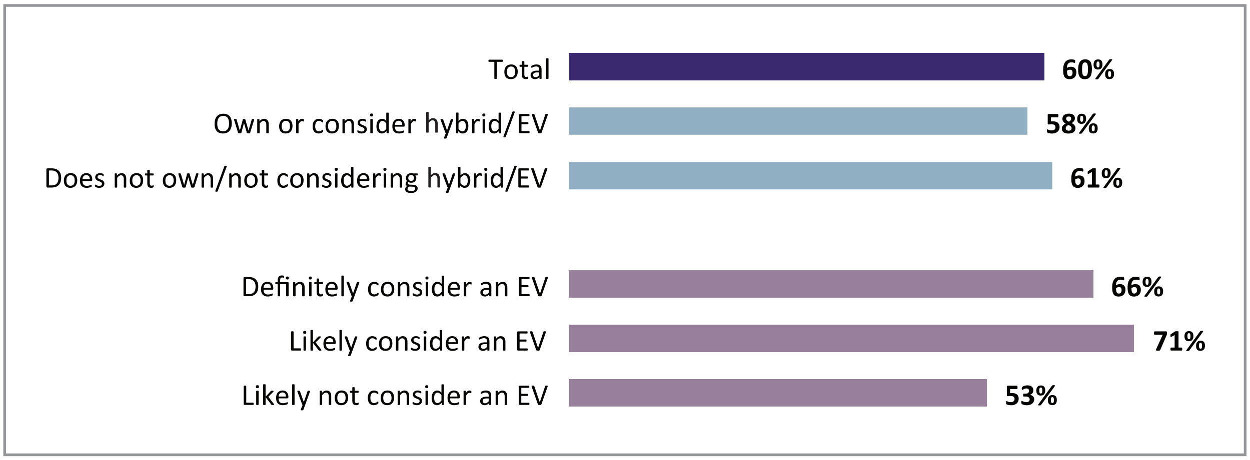


Subsample: Important to charge EV faster (N=496)

More than half of potential early adopters would be willing to pay two dollars more per hour to charge an EV at a public parking space.

When those who own an EV or would at least marginally consider one were asked if they would be willing to pay two dollars per hour more than the standard parking rate to be able to charge their vehicle while parking, six in ten said that they would be willing to do so. Just over one quarter of potential early adopters said that they would not pay extra, while one in ten said that it would depend, for example, on how much charge was needed or if other parking spots were available. It should be noted that, in practice, EV owners familiar enough with their vehicle's range might not be willing to pay an extra fee because they would feel confident that they could wait to return home to charge their EV.

Figure 16: Willingness to Pay an Additional Two Dollars per Hour to Charge at a Public Parking Space

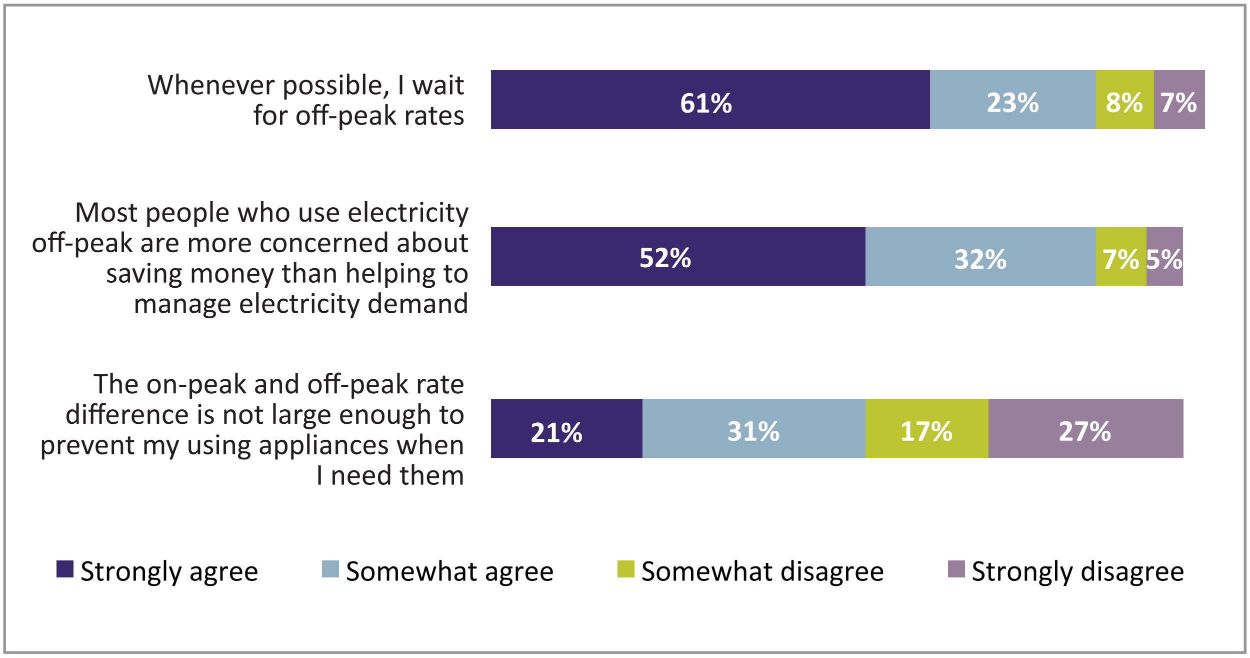


Subsample: Would definitely/likely/likely not consider an EV (N=523)

The majority of potential early adopters wait to use high electricity consumption devices during off-peak hours.

Potential early adopters were asked to indicate their level of agreement with three statements about time-of-use rates. The majority strongly agreed that "Whenever possible, I wait for off-peak rates before using high electricity consumption devices, such as clothes dryers or dishwashers." About half also agreed with the following statement: "Most people who use electricity off-peak are more concerned about saving money than about helping to manage electricity use across the grid." However, agreement was divided about the statement "The difference between on- and off-peak rates is not large enough to prevent me from using a high electricity consumption appliance whenever I need it." This suggests that EV charging behaviours would likely be similar, with most potential early adopters opting to charge off-peak to save money if possible but not regarding time-of-use rates as sufficiently compelling to prevent them from charging on-peak if need be.

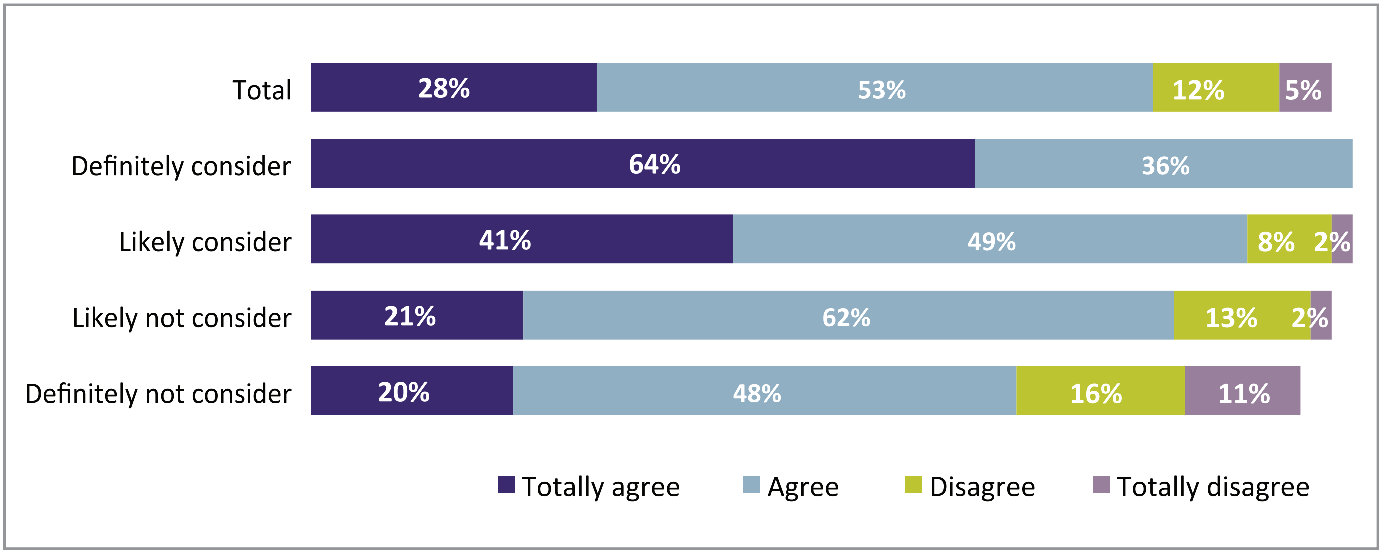
Figure 17: Statements for Encouraging Off-Peak Charging



Validation of Preliminary Assumptions

Potential early adopters who said that they would definitely consider an EV expressed greater agreement with statements about ecological consciousness, interest in technology and consumptivity than those less likely to consider an EV. This helps to validate the initial assumptions and criteria used to profile early adopters during the secondary research. In particular, potential early adopters felt strongly about their ecological consciousness and interest in technology.

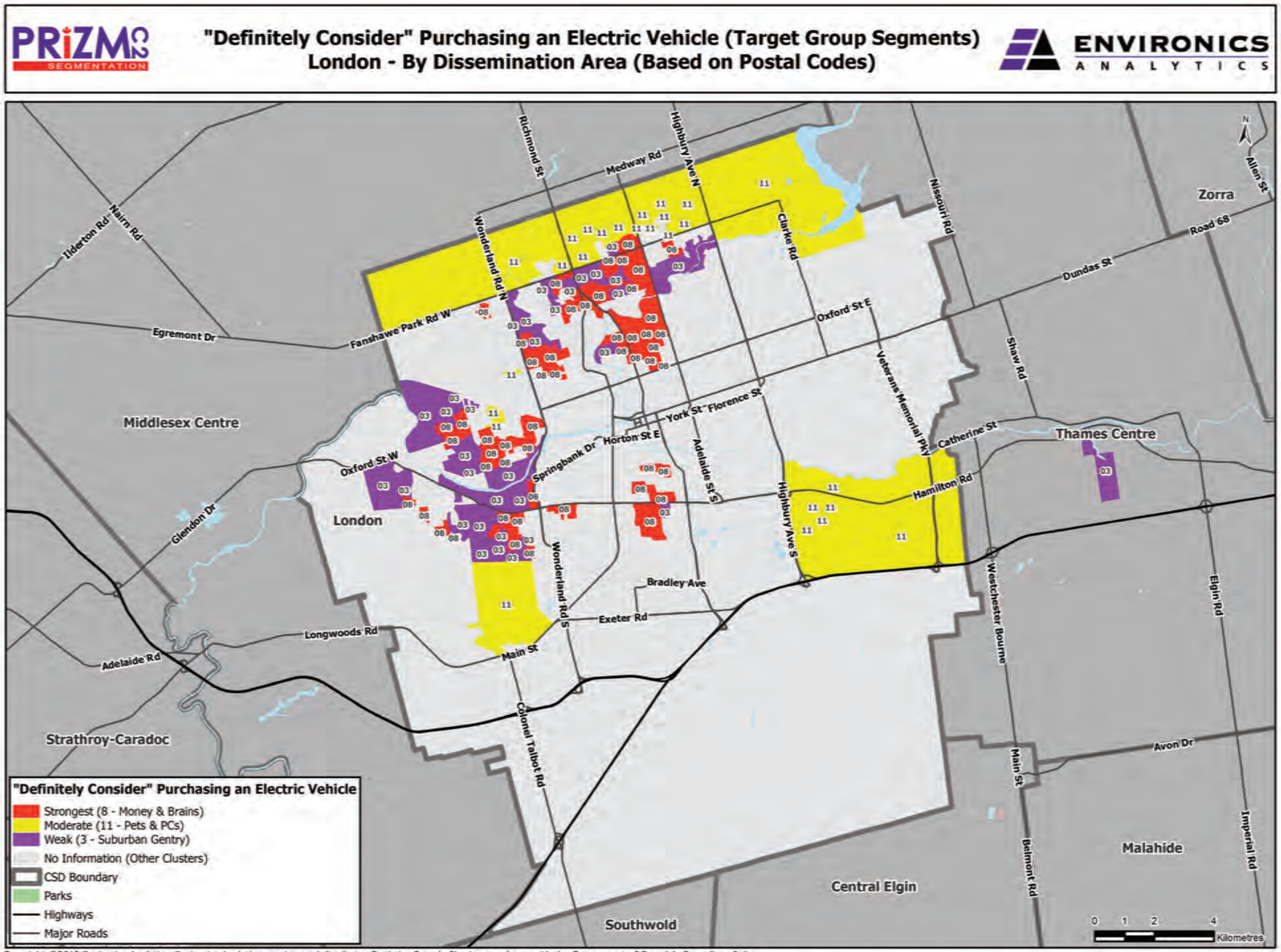
Figure 18: Responses to the Statement "I am excited about the possibilities presented by new technologies" by Likelihood of Considering an Electric Vehicle in the Next Two Years



Note: does not include "don't know" and "neither agree nor disagree."

Each of the eight early adopter segments was cross-referenced with the number of "definitely consider" responses about a potential EV purchase and rated according to strong, moderate or weak interest. The original segment map was then recalibrated to reflect the relative strength of interest in acquiring an EV. The recalibrated map (see Figure 19) details the areas in the City of London where the adoption of EVs will likely take place.

Figure 19: Strength of Interest in Purchasing an Electric Vehicle by Dissemination Area in the City of London



Note: CSD – Census subdivision.

Summary

The results of the household telephone survey build a better picture of the characteristics of potential early adopters, including a broad demographic profile, typical personal mobility patterns and clearly articulated perceptions of the barriers to and opportunities for the uptake of EVs. The findings from the household telephone survey provide a robust foundation for determining strategies to facilitate the successful uptake and integration of the technology in the City of London.

Potential early adopters in the City of London are more likely to be over the age of 45, more affluent and better educated than the general population. Few potential early adopters report having personal experience driving or riding in an EV, but there is evidence of a broadening general knowledge about EVs. A majority of the early adopter group are able to name at least one hybrid or fully electric vehicle (usually the Toyota Prius). However, this does not necessarily mean that a deeper understanding of the technology has developed; potential early adopters are generally not very familiar with the impact of EVs on the environment, how they compare with conventional vehicles, how the technology works or current government incentives designed to encourage their use. These findings suggest that a lack of awareness of EVs may underlie much of the resistance to the technology and points to opportunities for further education.

The survey results suggest that even among potential early adopters, purchasing or leasing an EV is not imminent. Concerns about the purchase price and current lack of infrastructure, as well as the potentially limiting range of the vehicle, are perceived as major barriers to the adoption of EVs. Interestingly, some of these perceived barriers do not align with the typical needs of the user. For example, while half of early adopters regularly drive less than 25 kilometres a day, the majority think that an EV would need to be capable of a range of more than 200 kilometres for them to feel confident that they would not be stuck somewhere without access to charging facilities. This finding suggests that range anxiety may be related to planning for worst-case scenarios as opposed to the respondents' typical driving patterns.

The survey results suggest that even among potential early adopters, purchasing or leasing an EV is not imminent.

The survey findings also identified important opportunities for the promotion of EV uptake. For example, the majority of potential early adopters felt that access to faster home charging would be very important. This points to an opportunity to promote technology that enables faster home charging as a means of overcoming a perceived barrier. The survey also shows that the LDC is the proponent most trusted to install and maintain a Level 2 residential charging station and to act as a facilitator of EV adoption for the early adopter group. The LDC already has a clear stake in preparing for EV deployment because of the need to meet the demand for additional electricity. Given that the survey results showed a high level of trust in the LDC among potential early adopters, there is also an opportunity for it to play a vital role in the promotion and success of EV deployment.

The market research can be used to determine methods for advancing awareness of the value proposition of EV use among potential end-users, establishing a solid foundation for the growth of the EV industry.

The market research can be used to determine methods for advancing awareness of the value proposition of EV use among potential end-users, establishing a solid foundation for the growth of the EV industry. The results can inform a comprehensive understanding of the knowledge and information required to plan and prepare for the continued deployment of EVs in the City of London. Unless the barriers identified in this report are addressed, scarce and valuable resources may be misallocated or misaligned with the needs of the emerging market for EVs, thus decreasing the efficiency of these investments and increasing the cost of enabling EV use in London.

Section Two of the EMAP report has described the methodology and results of two separate but interrelated market research investigations. Section Three of the report describes the process of assessing the capacity of the electricity distribution system to accommodate the additional loading predicted as a result of the uptake of EVs.

SECTION THREE:
Electricity Distribution System Assessment

Purpose of Assessing the Electricity Distribution System

The electrical power generation and transmission systems serving the City of London are capable of supporting a robust market for EV charging and use. However, the capacity of the local distribution system to deliver power to EV end-users could become constrained under certain conditions. The EMAP market research survey showed that potential early adopters of EV technology may exhibit consumer values that are shared by others in their communities. This could lead to “clustering” of early EV adopters, which, in turn, could create conditions in which the electricity distribution system might be constrained in its capacity to support EV-related loads.

The EMAP market research survey generated a body of evidence that richly characterizes the market for EVs in London. It also provides a better understanding of the nature of the charging services required to support EV deployment (i.e., when vehicles would be plugged in, for how long, and the importance of fast charging to the end-user). The findings from this market research were the basis for an assessment of the capacity of the electricity distribution system to accommodate the predicted patterns of demand for power to charge EVs.

Understanding how EVs are likely to change the profile of power demand at the neighbourhood level is critical to making informed, strategic and effective investments in technology and infrastructure to maintain and improve quality of service.

Understanding how EVs are likely to change the profile of power demand at the neighbourhood level is critical to making informed, strategic and effective investments in technology and infrastructure to maintain and improve quality of service. At the same time, it is important for the LDC to clearly understand the impact of EV penetration across the entire electricity distribution system. The findings in this report identify the needs of the early adopter market, defined by location and mobility patterns, and the key barriers to EV charging and use that must be addressed. As such, this report can provide a foundation for developing strategies to enable the use of EVs in the London Hydro service area.

Terms and Definitions

The following section provides an overview of a number of key terms related to the basic units of electricity as well as power system configurations, with examples drawn from the City of London and the London Hydro service area. The definitions and descriptions are provided solely for the purpose of supporting the discussion of the EMAP electricity distribution system assessment and are not intended to reflect the intricacies of either the basic units of electricity or electrical power systems in general.

Basic Units of Electricity

The following basic units of electricity are used throughout this report in relation to potential constraints on the electricity distribution system:

Current (I) is the flow of electric charge through a conductor, such as a copper wire. Current is measured in amperes (A), often referred to as amps. Electrons are induced to move by electromagnetic forces, described as voltage.

Voltage (V) is a measure of electrical energy, or the *work* that an electromagnetic field can impart to a charged particle. Measured in volts (V), it is the energy that induces electrons to move in a conductor. Volts are also used to express the voltage applied to a circuit by an energy source, such as a battery or an electrical generator; in this context, voltage can also be referred to as **electromotive force**.

Resistance (R) is a measure of a material's tendency to oppose the flow of electrical current. Resistance is expressed as the ratio of voltage to current and is measured in ohms (Ω). The greater the resistance, the less electrical current flows through a conductor and the more the voltage (i.e., the electrical energy) applied to the conductor is converted to heat energy that dissipates into the immediate surroundings. Keeping current levels low in an electric wire is one way to minimize the amount of electrical energy that is converted to and lost as heat. Such losses are known as **line losses**.

This report also makes frequent references to three other terms related to electricity: **power**, **load** and **energy**.

Power is the time rate at which energy (e.g., the energy of electrons carrying charge to a battery through a conducting wire) is transferred or converted. Power is expressed as the product of voltage and current, and is measured in watts (W). For example, a wire carrying a current of 15 A at 110 V is transferring energy at a rate of 1,650 W. A watt is a per-second measure of energy transfer or conversion. A kilowatt (kW) is equal to 1000 W and is one of the units typically used to express the maximum power characteristics of an electric motor or a transformer. For example, the charging systems built into new EVs (i.e., the on-board chargers) referenced in this report are rated in kilowatts. Power is also measured in kilovolt-amperes (kVA). The rated power capacities of the transformers investigated in this report are expressed in kilovolt-amperes, which include active power (the power consumed by the customer load) and reactive power (the energy exchanging within inductors and capacitors in the grid). All load profiles are expressed in kW because, at the customer level, reactive power is very small compared with active power.

A **load** is any device that uses electrical energy or changes it into other forms of energy (e.g., heat, light, mechanical energy). An EV plugged in to charge its battery is an example of an electrical load. If the EV is plugged into a socket that supplies electricity at 15 A and 110 V, power flows at 1,650 W – similar to a typical hair dryer.

Energy, measured in kilowatt-hours (kWh), is the product of the power (i.e., the rate at which energy is transferred) and the time over which it is supplied (Energy = Power x Time). An EV battery charging at 1,650 W for eight hours stores approximately 13 kWh of energy.

What is the difference between a watt and a volt-ampere?

Both watts and volt-amperes can be used to express power when direct current (DC) circuits are being measured. In alternating current (AC) circuitry, which is a more common design in transmission and distribution systems, volt-amperes are used to accurately express more complex power characteristics.

The Electrical Power System

The primary focus of the electricity distribution system assessment is the distribution system at the secondary, or neighbourhood, level. To better understand the implications of EV charging for the distribution system, it is important first to explore the functions of some of the electrical power system components. The following section provides a simplified description of these functions; it is not intended to reflect the intricacies of any particular system.

The purpose of the electrical power system is to connect the centres of demand for electricity (i.e., the end-users) with the sources of supply (i.e., the power plant). Because the capacity to store electricity once it is generated is limited, the balance of supply and demand in Ontario is delicately managed on an instant-by-instant basis by the Independent Electricity System Operator (IESO). If customers generated their own electricity to meet their individual needs, no system of transmitting or distributing power would be needed. In reality, however, because the centres of demand are usually located far from the sources of supply, transmission and distribution are essential elements of today's power system.

In general, the power system involves electricity being generated at a power plant, where it is converted, or "stepped up," to very high voltages for transmission over long distances and then "stepped down" to lower voltages for distribution to end-users.

GENERATION

At the core of almost all generating stations is a series of turbines that are driven by water, steam or combustion gases. Connected by a driveshaft, the turbines cause an electromagnet inside the generator to rotate. The movement of the magnetic field induces a current in the surrounding coils of wire within the generator, producing a voltage that can feed the transmission system. The voltage levels generated are directly related to how quickly and with how much force the generator spins. Some generating stations in Ontario are privately owned and operated, while some are publicly owned. The largest power generator in the province is a Crown corporation, Ontario Power Generation.

TRANSMISSION

A **transmission substation** is located at or near the generating station. The transmission substation contains a large **step-up transformer**, which increases the voltage produced by the generator to the high levels required for long-distance transmission. Electrical power systems generally use a series of transformers to convert electricity to different voltage levels appropriate for each stage of the system.

Individual households are usually located far from the generation station. To reach the consumer, the electricity generated must be conducted by wires spanning long distances. High-voltage **transmission lines** are used for this purpose. A few high-voltage transmission lines can carry more electrical energy, more efficiently, than a larger number of lower-voltage lines. Also, the transmission of electrical power at high voltage keeps current levels low, and this minimizes resistance and line losses. While for the majority of end-users, these high voltages need to be reduced (stepped down) to a lower level for household or small business use, some industrial facilities with high electrical loads (e.g., high-power motors) may be connected directly to the transmission system. The transmission company responsible for transmitting electricity to the City of London is Hydro One Networks, Inc. The transmission lines servicing the city operate at voltages of 230 kV or 115 kV.

Step-down transformers are found at transmission stations located close to or in the city. These transformers convert the high voltages from the transmission lines to lower voltages for distribution. These transmission stations and lower-voltage transmission lines are sometimes referred to as the **subtransmission system**.

How does a transformer "step down" or "step up" voltage?

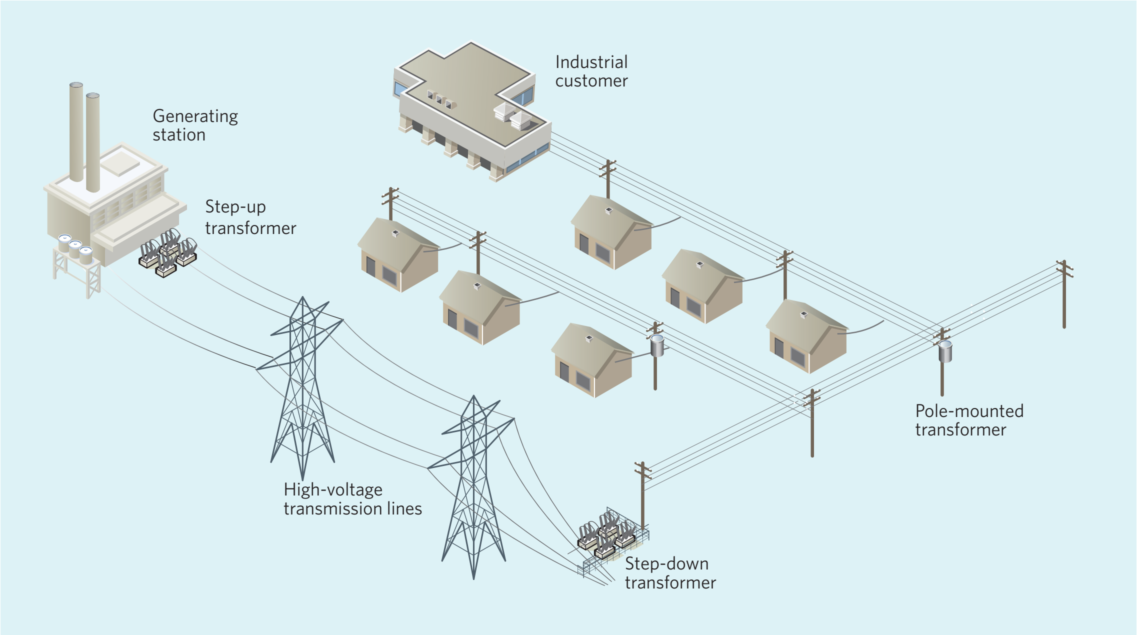
Transformers neither produce nor consume power or energy. But, by regulating power to the right levels, they make it possible for devices of all types and purposes to operate on just a few levels of power supply.

Transformers at their most essential level consist of parallel but separate coils of wire wound around a magnetic core. When voltage is applied to one coil (usually called the primary or input), it magnetizes the iron core, which induces a voltage in the other coil (usually called the secondary or output). If the secondary coil has fewer loops than the primary coil, less voltage and more current is induced in the secondary coil. This is the case with a "step-down" transformer. A "step-up" transformer works in the opposite way. With more loops in the secondary coil than in the primary coil, it increases voltage and reduces current. The turns ratio (the ratio of the number of turns on the primary coil of an electrical transformer to the number on the secondary) of the two sets of windings determines the amount of voltage transformation.

DISTRIBUTION

Electricity distribution is the final step in the delivery of electricity to end-users. The distribution system takes the electricity carried along the high-voltage transmission lines and, through a series of step-down transformers, lowers the voltage to levels appropriate for use by individual households and businesses. The distribution system is owned and operated by LDCs. As previously mentioned, London Hydro is the LDC for the City of London.

Figure 20: Electricity Generation, Transmission and Distribution System



The **transformer station** is where the transition from transmission to distribution occurs. These transformers step down the voltage from transmission levels (230 kV and 115 kV) to distribution levels. There are six transformer stations in the London Hydro service area, all owned by Hydro One Networks, Inc. Five of these transformer stations step down voltage to 27.6 kV and one station to 13.8 kV. **Distribution feeders** (electrical cables or conductors) running from transformer stations distribute electrical power to transformers located overhead or underground or to smaller **municipal substations**. In the London Hydro system, the 27.6 kV feeders supply power to such substations, where voltage is then converted to 4.16 kV and, at one substation, to 8.32 kV. It should be noted that both the 4.16 kV and 13.8 kV systems are gradually being decommissioned in an effort to adopt a system-wide supply standard of 27.6 kV.

London Hydro's residential service area is supplied by two different distribution system configurations: the overhead distribution system and the underground distribution system. The overhead distribution system primarily supplies power to the central and older parts of the city, while the underground distribution system primarily provides power to those neighbourhoods located outside the centre of the city. Figures 21 and 22 illustrate the distribution transformers by system voltage for the overhead distribution system and the underground distribution system, respectively.

Figure 21: London Hydro Overhead Distribution Transformers by System Voltage

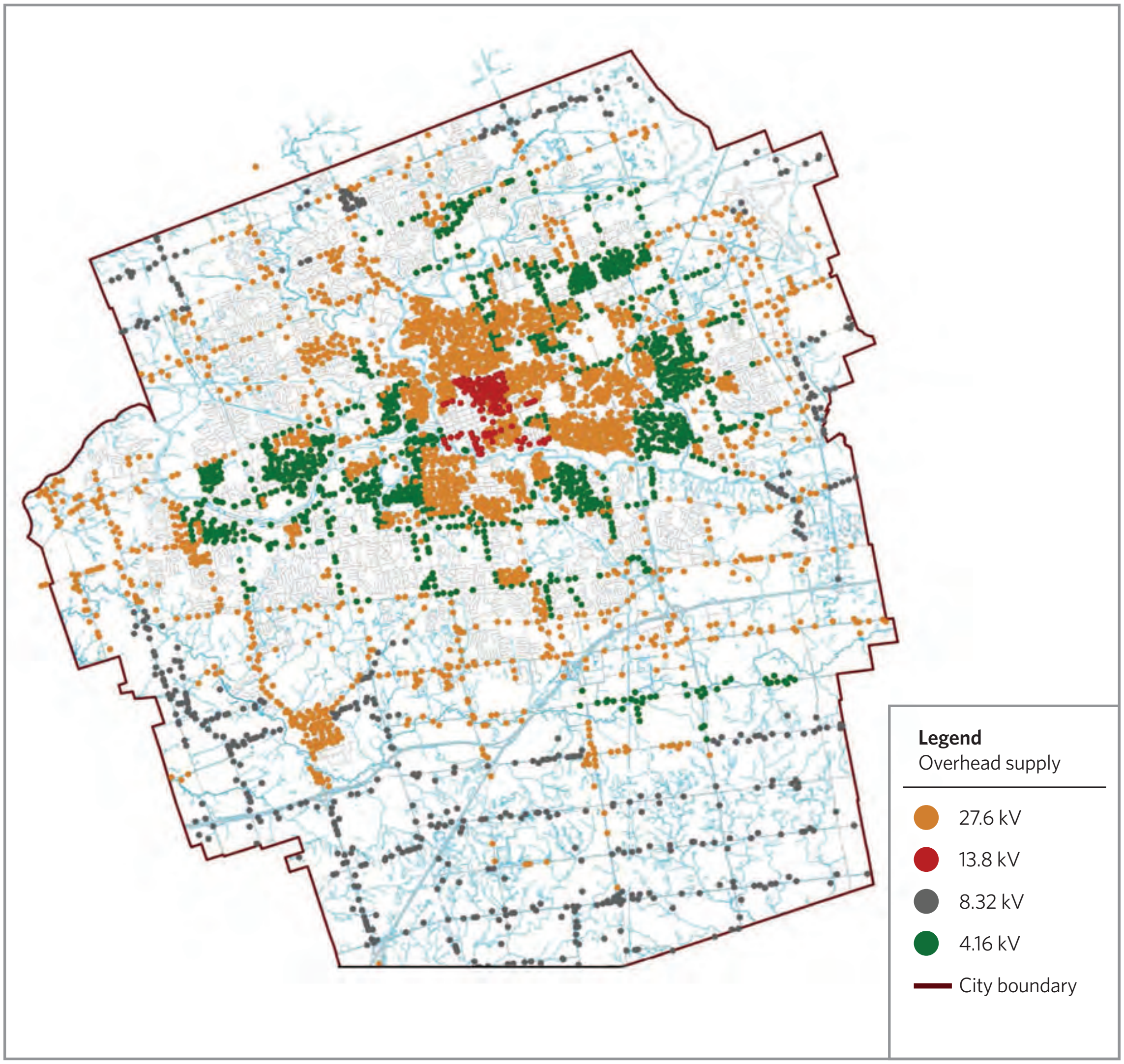
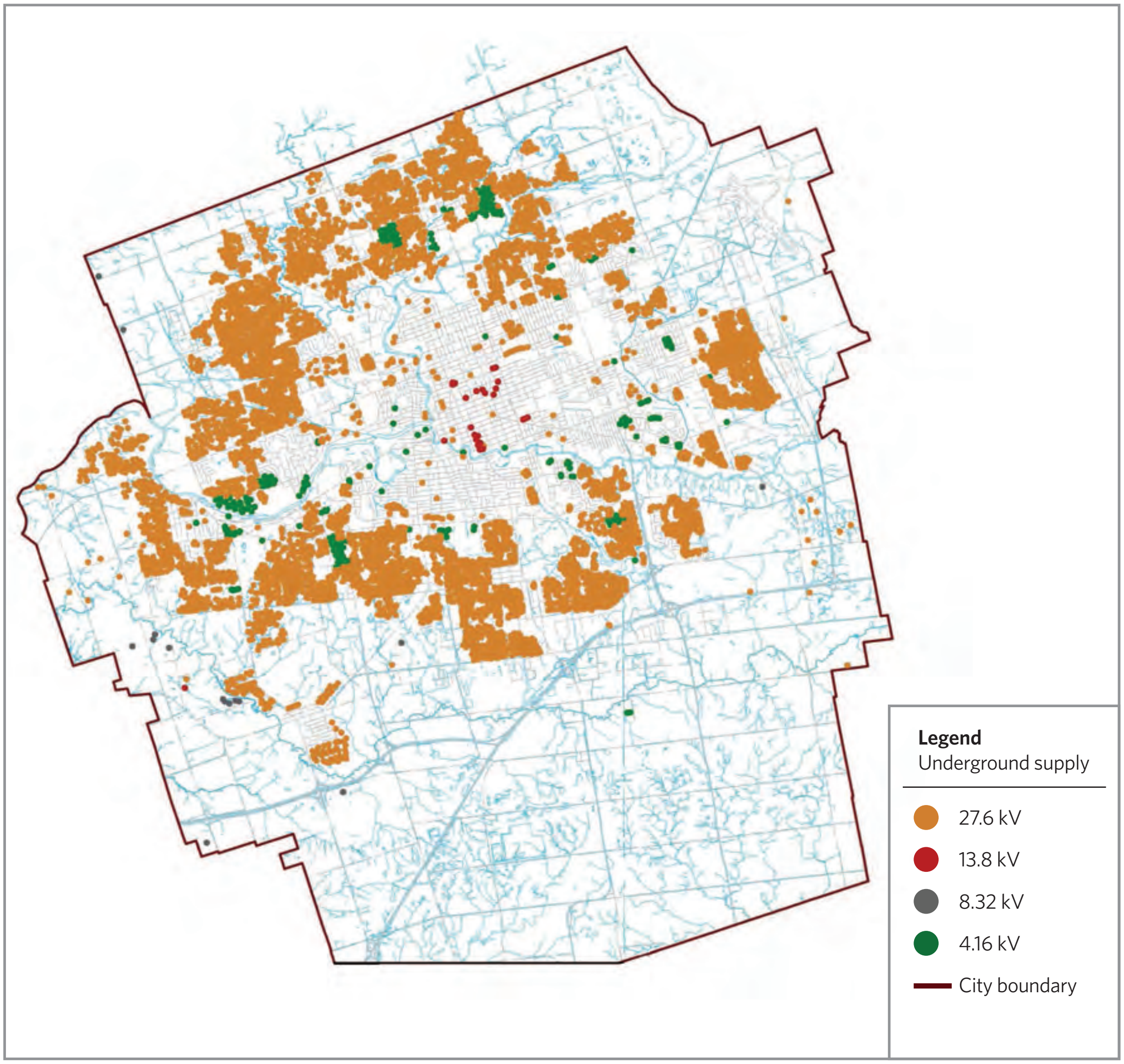


Figure 22: London Hydro Underground Distribution Transformers by System Voltage



LOCAL TRANSFORMERS

Pole- or pad-mounted transformers provide the final voltage transformation in the London Hydro electrical power system. These transformers step down the voltage from distribution levels to the level appropriate for use by individual households (typically 120 V and 240 V).

When distribution feeders are located overhead, the transformer is usually mounted on a utility pole and is referred to as pole-mounted. When the distribution feeders run underground, the transformer is mounted on a concrete slab (pad-mounted).

SECONDARY CONNECTION SYSTEM

The secondary connection system supplies power from the pole- or pad-mounted transformer to the end-user. In the overhead system, the secondary connection system for a pole-mounted transformer consists of the following:

- The **secondary drop lead** is a conductor connecting the transformer to a secondary bus.
- The **secondary bus** is a common electrical connection point for individual service cables running directly to each household serviced by the same transformer.
- **Service cable**s connect the secondary bus to the end-user. Service cables are the last stage of the distribution system.

Pad-mounted transformers typically supply power to end-users through buried service cables that run from the transformer to the individual customer. For the purposes of this report, the neighbourhood-level distribution system is defined as either the pole- or pad-mounted transformer and anything beyond it (i.e., the secondary connection system).

Methodology

To better understand the implications of the anticipated uptake of EVs in the context of electricity demand in London, scenario development and simulation were undertaken to assess the electricity distribution system's capacity to support additional loading resulting from EV charging. The process involved an assessment of the distribution system at the neighbourhood level, including pole- and pad-mounted transformers and the secondary cables responsible for running electrical power to individual households in the overhead distribution system. The impacts of EV charging on the distribution system were simulated by London Hydro, using actual residential transformer loads.

The specific process, outputs and assumptions made in the development and application of the assessment are described below. Each of the scenarios modelled reflects a steady-state analysis as opposed to real-time dynamic simulations, which were beyond the scope of this study.

Assessment of the Electricity Distribution System at the Neighbourhood Level

SCENARIO DEVELOPMENT AND RESULTS

By offering a means of investigating hypothetical situations, scenario development and simulation can inform the development of strategies to produce desired outcomes. A range of scenarios were investigated to better understand the extent to which a number of key variables could impact the capacity of the electricity distribution system at the neighbourhood level to accommodate EV charging at home. The scenario development consisted of investigating key variables and establishing the effects of EV charging on transformer aging. Some scenarios focused on individual transformers, while others examined the effects of EV charging on pole- and pad-mounted transformers across the entire London Hydro service area.

It is important to note that because the distribution system is made up of a range of transformers, the effects of EV charging will affect each transformer differently, based on its rated capacity, typical load profile, number of households served and the capacity of the vehicle's on-board charger.

The following section outlines both the process and the key findings of the electricity distribution system assessment, beginning with a discussion of the key variables predicted to have an effect on the capacity of the neighbourhood-level distribution system to support EV-related loads. This is followed by an investigation of the effects of EV charging on the lifespan of the transformer.

Investigating Key Variables

The first set of scenarios tested the capacity of the electricity distribution system at the neighbourhood level to accommodate the potential loading from EV charging. These scenarios were developed based on the predicted home charging patterns of early adopters of EV technology, three on-board charger capacities and the assumption that ambient temperature can create additional stress for the neighbourhood-level distribution system. While these conditions are not likely to occur simultaneously, this investigation allows for a better understanding of possible worst-case scenarios and key factors that could limit the number of EVs that can be accommodated by the electricity distribution system as it currently exists. Scenarios were developed and tested based on a number of key variables predicted to have the greatest potential for impacts on the capacity of the system to support EV-related loading.

The variables investigated were

- EV on-board charger capacity
- ambient temperature
- time of charge
- EV penetration rate

The key variables investigated are described in greater detail below.

Electric Vehicle On-Board Charger Capacity

As previously noted, most EVs can be charged using a standard 120 V household outlet (Level 1 charging). If a vehicle is charging at Level 1, power flows through the on-board charger at a lower rate than when it is charging at 240 V (Level 2 charging). For example, the 2014 Nissan LEAF can charge at 6.6 kW at 240 V, but power flows at 1.2 kW when the vehicle is charging at 120 V.

A number of EVs on the market have an on-board charger rated at 3.3 kW (e.g., the 2014 Chevrolet Volt plug-in hybrid electric) or 6.6 kW (e.g., the 2014 Nissan LEAF) when charging at 240 V. Compared to a 3.3 kW charger, a 6.6 kW charger significantly reduces the length of time required to charge the vehicle, but it also doubles the demand for power from the electricity distribution system. Even more powerful on-board chargers are also available, such as the 20 kW rated charger on board the Tesla Model S.

Table 1 summarizes the specifications for three popular EV models used as examples of the charger capacities investigated in this section of this report. Looking at a range of charger capacities allows for more in-depth analysis of the extent to which conditions such as ambient temperature or time of charge can affect the capacity of the electricity distribution system to meet the additional demand for power for EV charging. Level 1 charging is not investigated in this report because the load associated with charging an EV at Level 1 would have relatively little effect on the electricity distribution system and, moreover, the EMAP market research indicates that charging at Level 1 would take longer than the typical early adopter would likely be willing to wait.

Table 1: Charger and Battery Specifications for Various Electric Vehicle Models

EV model	Charging level, V	On-board charger capacity, kW	Battery size, kWh
2014 Chevy Volt	240	3.3	16
2014 Nissan LEAF	240	6.6	24
2014 Tesla Model S	240	20	85

Note: The Tesla website references both 20 kW and 22 kW as the on-board charger capacity for the Tesla Model S. For the purposes of this report, only 20 kW will be investigated.

Ambient Temperature

In summer, there is an increase in the demand for electricity to power air conditioners to cool houses. There is also a higher demand for power during the winter months; people tend to be inside longer, with the lights on and furnace fans and heaters running. These seasonal factors increase the load on the transformer. This means that the electricity distribution system could reach capacity during the summer and winter months at a lower EV penetration rate than it would during the times of the year with less extreme temperatures.

The scenarios investigating ambient temperature used transformer load data from the week of the previous summer when demand for power was greatest (July 14 to 20, 2013) to represent the worst-case for summer (i.e., summer peak). Data from the week of the previous winter when demand for power was greatest (January 5 to 11, 2014) were used to represent the worst-case for winter (i.e., winter peak). To determine the percentage load for each individual transformer, its overall load for the summer or the winter peak was divided by its rated capacity. For example, a transformer rated at 50 kVA with a load of 25 kVA during the summer peak would be considered to be loaded at 50 per cent of its rated capacity.

Based on its loading percentage, each transformer was assigned to one of the following three categories:

- **lightly loaded**: less than 50 per cent loaded (transformer loading less than 0.5)
- **moderately loaded**: between 50 and 100 per cent loaded (transformer loading between 0.5 and 1.0)
- **overloaded**: anything above 100 per cent loaded (transformer loading greater than 1.0)

Figures 23 and 24 show the distribution of transformers within the London Hydro service area based on these three categories for the day with the greatest demand for power in the summer (July 18, 2013) and winter (January 7, 2014), respectively. Each coloured area represents either a transformer or a group of transformers from the same category (e.g., blue areas represent a grouping of lightly loaded transformers) within the service area. These figures indicate that for the time periods investigated, a greater number of transformers in the London Hydro service area were considered overloaded during the summer peak than during the winter peak.

Figure 23: Transformer Loading on the Day with the Greatest Demand for Power in Summer (July 18, 2013)

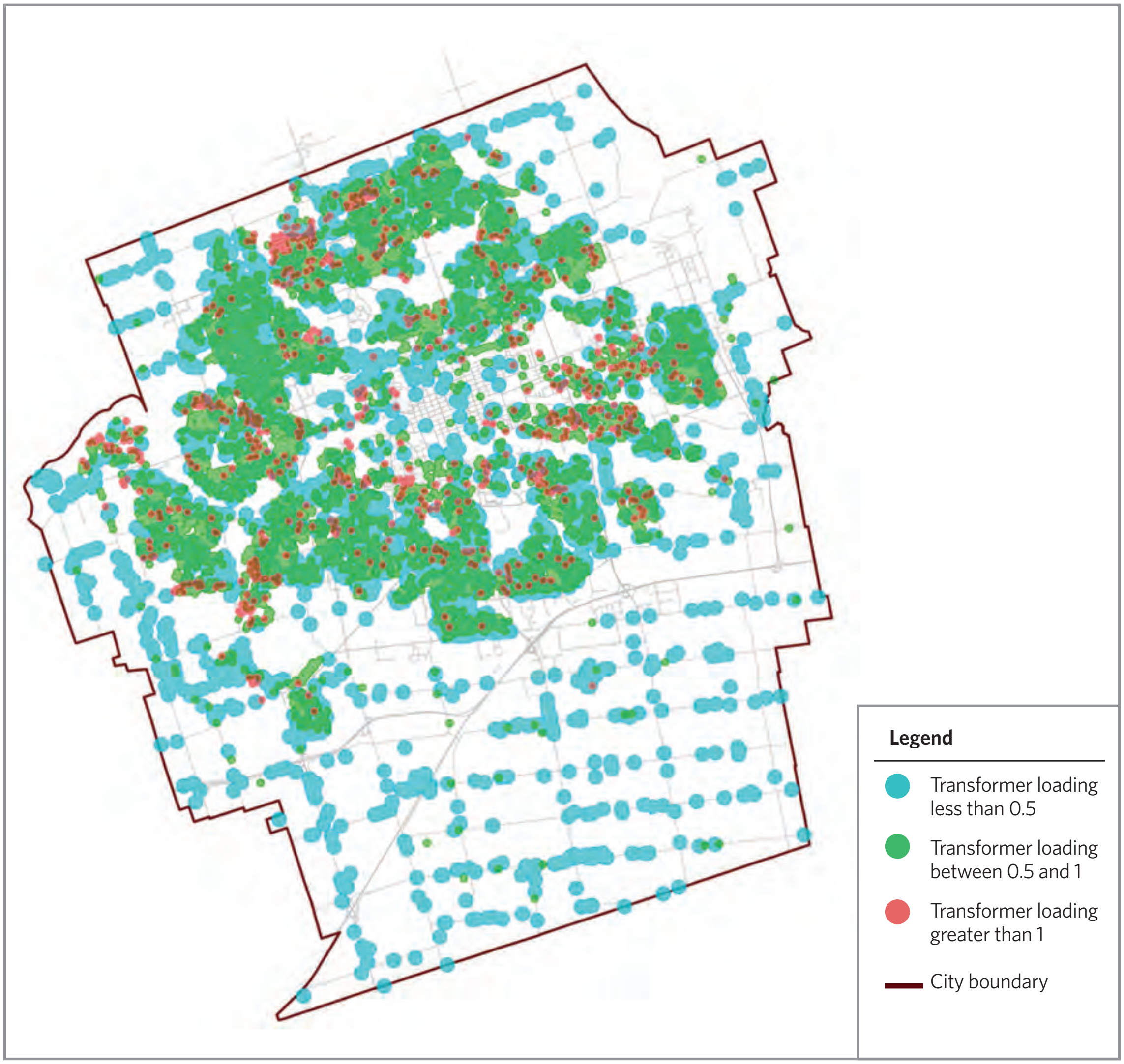
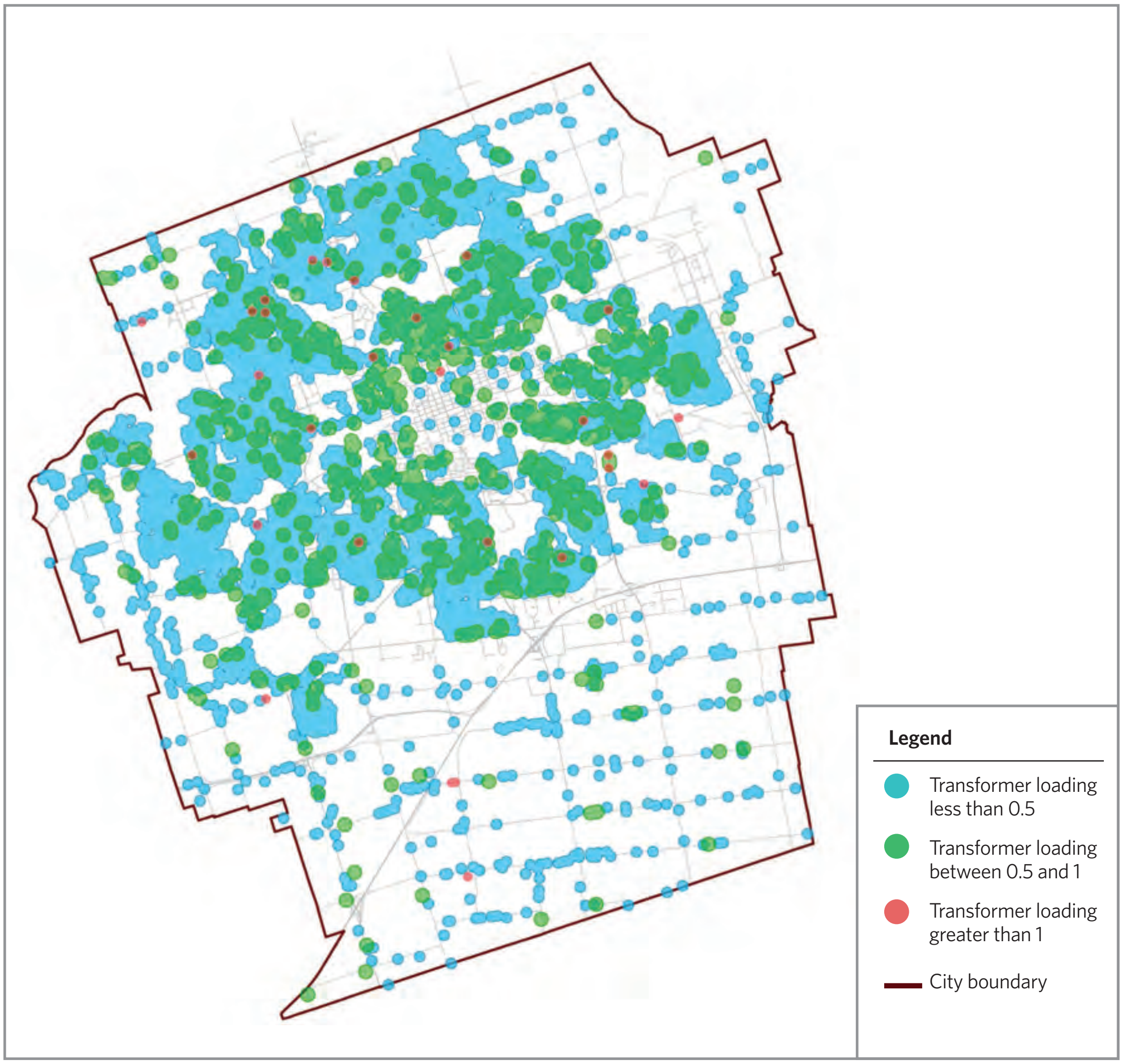


Figure 24: Transformer Loading on the Day with the Greatest Demand for Power in Winter (January 7, 2014)



Time of Charge

Because the demand for electricity fluctuates over the course of a day, the time at which EVs are plugged in has significant implications for electricity distribution system capacity. To better understand how time of charge affects EV charging, two pad-mounted transformers were selected to illustrate the effects of EV charging during on- and off-peak hours. The transformers selected both have a capacity of 50 kVA, a fairly common transformer size for the London Hydro service area.

Further details specific to each of the transformers used as examples are described below.

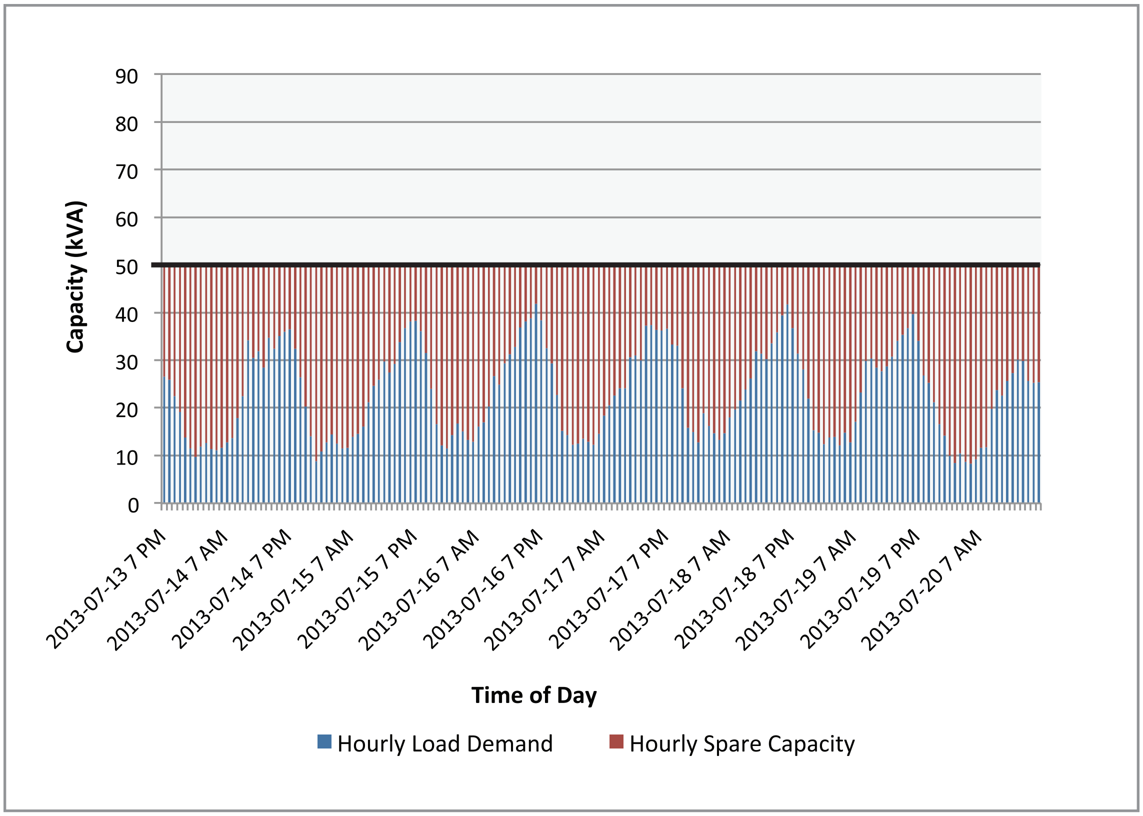
Transformer 1: This transformer provides power to seventeen condominium units. It is pad-mounted and, for the purposes of this assessment, considered to be lightly loaded. Condominiums and other multi-residential buildings do not necessarily align with the profile of the EV early adopter and, because of their size, units in such buildings typically demand less power overall than would be required for a typical single-family dwelling. Based on its load profile, this transformer is meant to represent a best-case scenario for EV charging.

Transformer 2: This transformer provides power to sixteen single-family dwellings. It is pad-mounted and, for the purposes of this study, considered to be overloaded. The EMAP market research shows that EV early adopters are more likely to reside in single-family dwellings, consistent with those provided with power by this transformer. Based on its load profile, Transformer 2 represents a worst-case scenario for EV charging.

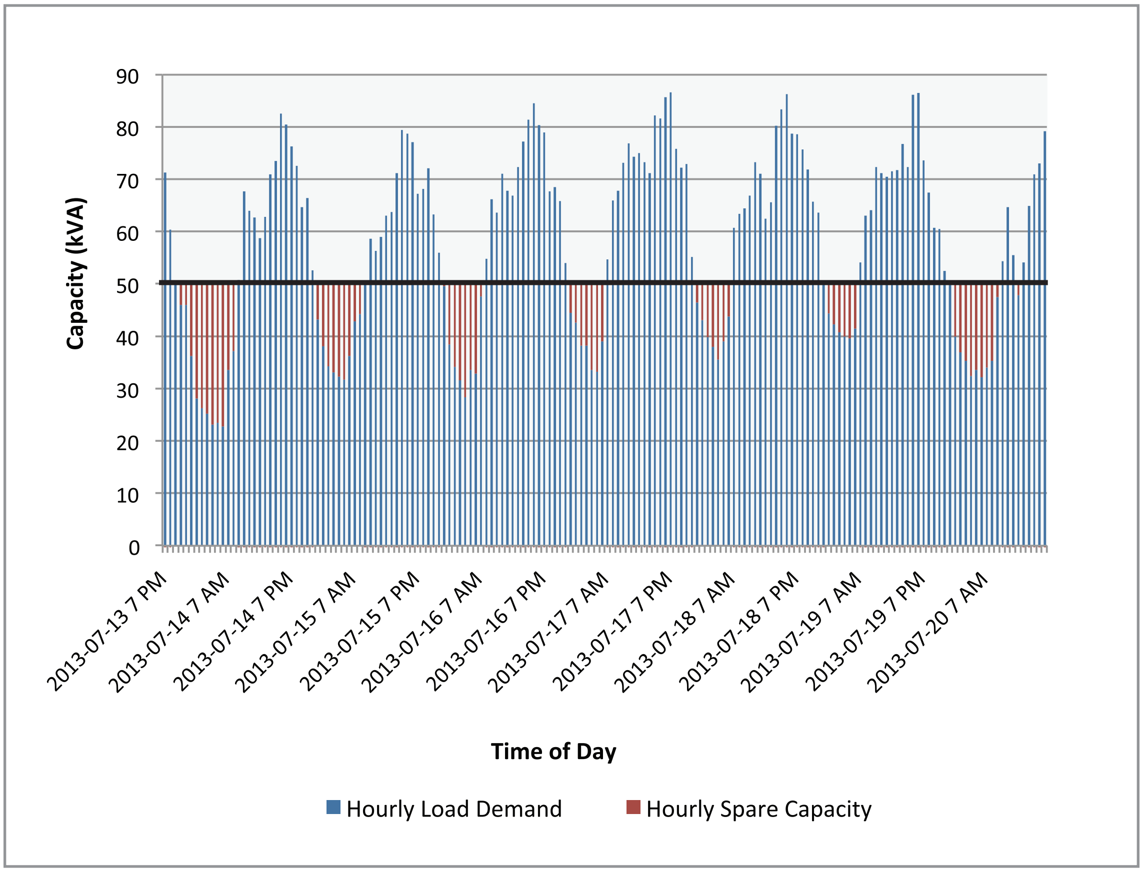
Before any additional loading from EV charging was considered, the 24-hour load profiles for the summer peak were generated for both transformers. Figure 25 shows the load profiles for Transformer 1 and Transformer 2, respectively, and illustrates that the demand for power fluctuates over the course of the day across the week in question. Transformer 1 was operating well below its rated capacity each day, even during times of peak demand. Transformer 2 was operating above rated capacity for the majority of the week, with relatively few intervals with spare capacity.

Figure 25: Transformers 1 and 2 Load Profiles for Summer Peak

(a) Transformer 1: supplies 17 condominiums



(b) Transformer 2: supplies 16 single-family dwellings



The hourly load profiles for the days in question were then grouped into the following two categories for further analysis:

- on-peak hours (between 7 a.m. and 7 p.m.)
- off-peak hours (between 7 p.m. and 7 a.m.)

The remainder of the investigation of key variables looks at the effects of different EV on-board charger capacities on the electricity distribution system at on- and off-peak times during the summer peak from the previous year (i.e., July 14 to 20, 2013).

Electric Vehicle Penetration Rate

As the results of the market research show, the rate of EV penetration is influenced by several factors, including demographics, consumer attitudes and the availability of charging infrastructure. At the same time, the number of EVs that can be charged simultaneously is limited by the capacity of the transformer and conductors to meet the demand for power. The following scenarios explore the impact on the transformer resulting from the number of EVs charging.

EV Penetration for a Single Transformer

The first scenario tested the capacity of a single transformer (Transformer 1) to accommodate vehicles with an on-board charger rated at 3.3 kW. The EV penetration rate was calculated by first determining the spare capacity of the transformer over a 24-hour period (from July 14 at 7 a.m. to July 15 at 6 a.m.). Spare capacity is a measure of the difference between the transformer's rated capacity (i.e., 50 kVA) and its overall load. The transformer's spare capacity was then divided by the rated capacity of the vehicle's on-board charger (i.e., 3.3 kW) to determine the total number of EVs that could be accommodated without exceeding the rated capacity of the transformer.

Figure 26 shows that the number of EVs with a 3.3 kW charger that Transformer 1 can accommodate varies significantly based on the time of charge. Figure 27 shows the average number of EVs that can charge simultaneously during on- and off-peak hours. Given the greater demand for power during on-peak hours, it follows that fewer EVs can charge simultaneously during this period than during off-peak hours without exceeding the rated capacity of the transformer. Despite Transformer 1 representing a best-case scenario, in that the transformer is categorized as lightly loaded, at no point can 100 per cent EV penetration (i.e., assuming one EV per household) with a 3.3 kW charger be accommodated by this transformer on the day in question.

Figure 26: Number of Electric Vehicles That Could Charge by Hour (3.3 kW On-Board Charger)

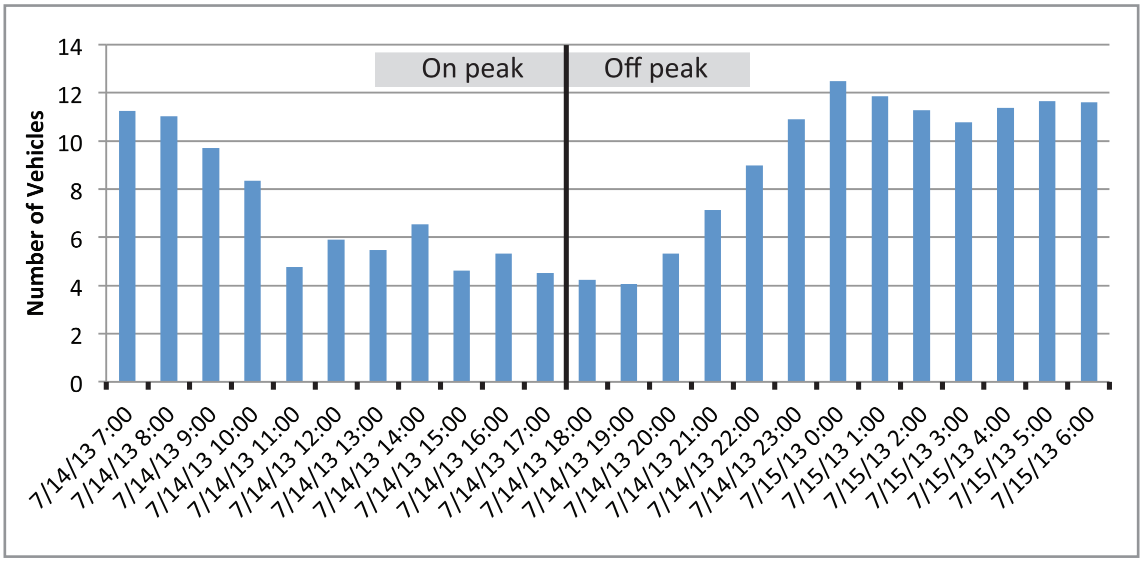
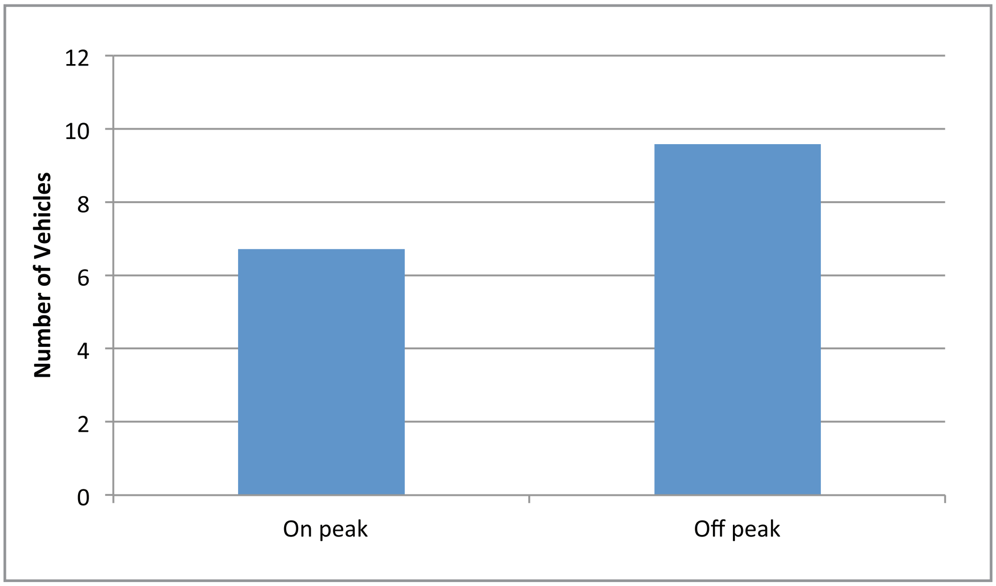


Figure 27: Average Number of Electric Vehicles That Could Charge On and Off Peak (3.3 kW On-Board Charger)

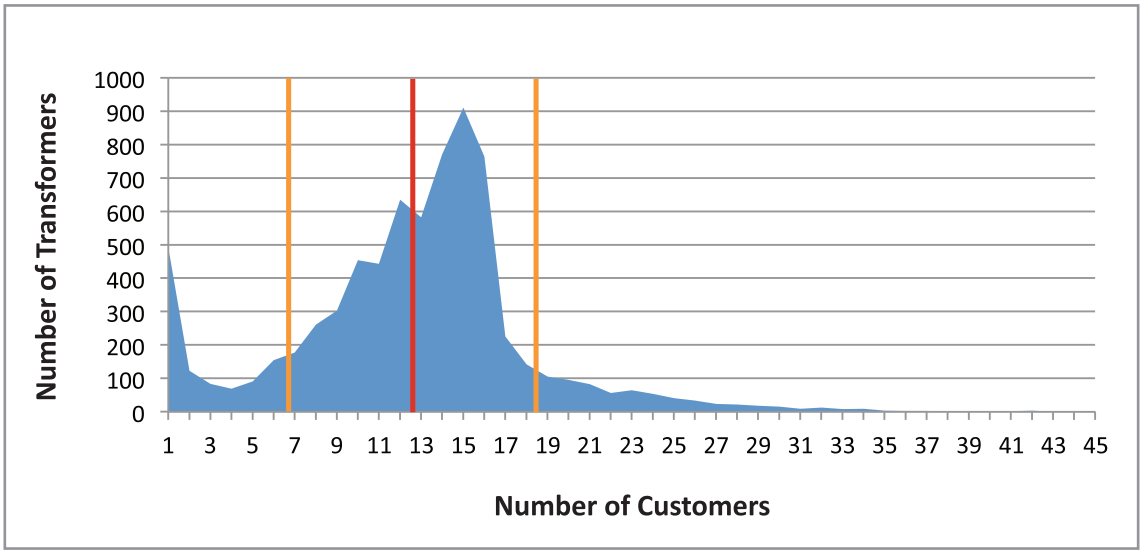


EV Penetration across the Service Area

This scenario investigated the average EV penetration rate for pole- and pad-mounted transformers across the London Hydro service area. Before specific scenarios were considered, the number of customers whose power is supplied by each transformer in the service area was determined, based on metering data from London Hydro. Figure 28 shows the distribution of customers served by each neighbourhood-level transformer within the London Hydro service area. An overwhelming majority of transformers provide power to between 6 and 18 customers. The average number of customers on a single transformer is 12 while the most common number is 15.

Around 500 of the total number of transformers investigated within the service area provide power to only one customer. The majority of these customers are either farms located in the rural areas surrounding the city or small commercial services. Because the load profiles for these customers do not align with a typical residential load profile or the early adopter neighbourhoods identified as part of the EMAP study, these transformers were excluded from the assessment, leaving 5,682 transformers (77 per cent of the total) to be assessed.

Figure 28: Number of Customers per Transformer in the London Hydro Service Area



Note: The transformers investigated are single-phase units because these are the only type of transformer used to supply power for residential loads in the London Hydro service area.

Three scenarios based on the capacity of the vehicle's on-board charger (3.3 kW, 6.6 kW or 20 kW) were investigated to determine the average number of EVs that could be accommodated by transformers across the electricity distribution system. Each of the 5,682 transformers was assigned to one of the three previously described categories (lightly loaded, moderately loaded or overloaded; see page 47), based on the percentage of its rated capacity at which it was loaded during the summer peak. These scenarios investigated all transformer capacities found within the London Hydro service area (10 kVA, 25 kVA, 37 kVA, 50 kVA, 75 kVA, 100 kVA and 167 kVA).

To evaluate the average number of EVs that could be accommodated by each transformer without exceeding its rated capacity, the average spare capacity for each of the 5,682 transformers was first determined for both on- and off-peak hours. The average spare capacity of each transformer for these time periods was then divided by the capacity of the EV on-board charger (3.3 kW, 6.6 kW or 20kW) to determine the total number of vehicles that could be accommodated on and off peak. These numbers were averaged across each loading category (i.e., less than 0.5, between 0.5 and 1.0, and greater than 1.0) to determine the total number of EVs that could charge on average without exceeding the transformer's rated capacity. The EV penetration rate was then calculated as a percentage by taking the average number of EVs that could charge for each transformer and dividing it by the number of customers provided with power by that transformer. For example, if the transformer could accommodate 5 EVs and provides power to 10 customers, the EV penetration percentage would be 50 per cent, or 1 EV for every 2 households. As a final step, the EV penetration percentage for each of the transformer loading categories was averaged to determine an overall EV penetration rate for each vehicle on-board charger size.

Table 2 shows the degree to which the capacity of the vehicle's on-board charger is a key factor in determining the EV penetration rate. For example, the EV penetration rate for vehicles with an on-board charger rated at 20 kW is much lower than for those rated at 3.3 kW during both on- and off-peak hours. The greater the transformer load before EV charging, the fewer EVs that can be accommodated without exceeding the transformer's rated capacity. In addition, fewer vehicles can be accommodated on peak, when the demand for power is greater, than off peak. It should be noted that the number of vehicles is an average and incorporates all transformer rated capacities across the service area, ranging from 10 kVA to 167 kVA. For example, while 16 EVs with a 3.3 kW charger may easily be accommodated by a transformer rated at 75 kVA or greater, depending on its spare capacity, the same number of vehicles on a 25 kVA transformer would cause overloading. As such, the size and spare capacity of each transformer must both be taken into consideration to determine the effects of EV charging on the electricity distribution system.

Table 2: EV Penetration across the London Hydro Service Area

	Loading factor	Tx count	On-peak penetration rate, %	Off-peak penetration rate, %	Average, %
Scenario 1 (3.3 kW)	Tx < 0.5	1660	51.6	54.0	**32.4**
	0.5 ≤ Tx < 1	3575	25.5	30.2	
	Tx ≥ 1	447	9.0	15.2	
Scenario 2 (6.6 kW)	Tx < 0.5	1660	25.8	27.0	**16.2**
	0.5 ≤ Tx < 1	3575	12.8	15.1	
	Tx ≥ 1	447	4.5	7.6	
Scenario 3 (20 kW)	Tx < 0.5	1660	8.5	8.9	**5.3**
	0.5 ≤ Tx < 1	3575	4.2	5.0	
	Tx ≥ 1	447	1.5	2.5	

Tx = transformer

Effects of Electric Vehicle Charging on the Secondary Connection System

The capacity of the secondary cables to accommodate EV charging without overloading varies based on the current capacity and characteristics of the conductors. In the London Hydro service area, these factors are primarily a function of when the secondary cables were installed, with a variety of different constructions, sizes and arrangements found throughout the city.

The secondary drop lead, secondary bus and service cable type with the least current capacity in an overhead system within the service area were investigated because they would represent the worst-case scenario in relation to the effects of EV charging on the secondary connection system. See Figure 29 for a representation of a typical overhead secondary connection system.

Figure 29: Secondary Connection System for a Pole-Mounted Transformer

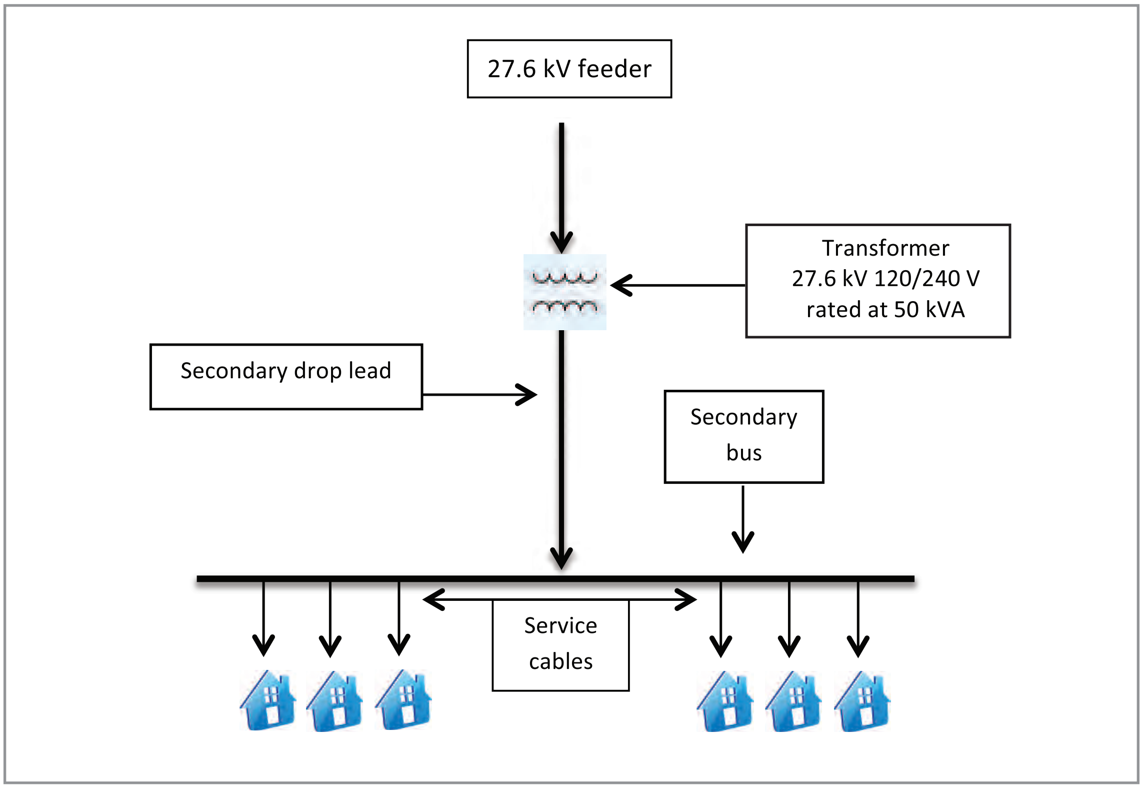


Table 3 shows the results of the assessment of a secondary connection system assumed to be supplying power to a total of 15 customers, with an average household load of 3 kW. The table shows that the secondary drop lead could accommodate 7 EVs with an on-board charger rated at 3.3 kW. However, just two EVs with the same capacity charger could be accommodated without overloading the secondary bus. The individual service cables running from the secondary bus to each household could accommodate only one EV charging with a 3.3 kW charger.

The number of EVs that can charge simultaneously drops dramatically for vehicles with a 20 kW on-board charger, with just two causing overload of the secondary drop lead. The secondary bus and the service cables would be unable to accommodate any EVs with a 20 kW charger without overloading. These findings point to the secondary bus as the limiting factor for each charger size. In other words, for each charger size, of the components of the secondary connection system (secondary drop lead, secondary bus or service cable), it is the secondary bus where overloading would come into play first as a constraint. These results can be used to help to identify potential problems related to the impact of EVs on the secondary connection system.

Table 3: Capacity of Overhead Secondary Connection System Components to Accommodate Electric Vehicle Charging

Secondary connection system component	Conductor size	Rated capacity, A	Number of homes supplied (3 kW average load per household	Number of EVs (Penetration, %)		
				EV charger capacity		
				3.3 kW	6.6 kW	20 kW
Secondary drop lead	No. 1/0 AWG stranded copper	285	15	7 (47%)	3 (20%)	1 (7%)
Secondary bus	No. 2 AWG stranded copper	215	15	2 (13%)	1 (7%)	0 –
Service cables	No. 4 AWG stranded aluminum, triplex	100	1	1 (100%)	1 (100%)	0 –

Establishing the Effects of Electric Vehicle Charging on Transformer Aging

The degree to which EV charging could contribute to a reduction in the lifespan of a transformer is an important consideration, given the costs associated with upgrading or replacing such equipment. A transformer's rate of aging and overall lifespan are determined by the condition of its internal insulation materials because they typically wear out before other components. The temperature of the transformer insulating materials – more specifically, the hottest location within the transformer components (typically within its windings), known as the internal hot spot – impacts the rate at which the insulation materials deteriorate. The temperature of the hot spot depends on factors such as ambient temperature and the load on the transformer. The transformer's insulation materials deteriorate more rapidly the hotter the internal hot spot gets and the longer it stays hot.

Because the load on the transformer impacts the temperature of its internal components, the increased load from EV charging could greatly affect the lifespan of transformer insulation. Moreover, if EV charging occurs at night, it would cut into the transformer's cooling cycle (reduced loads during off-peak hours and lower ambient temperatures at night typically allow a transformer's insulation temperature to decrease). For these reasons, it is important to better understand the extent to which EV charging could impact the life expectancy of a transformer.

The manufacturer of London Hydro's pad-mounted transformers conducted an assessment of the possible effects of EV charging on transformer aging, using a method outlined in IEEE C57.91-2011, *Guide for Loading Mineral-Oil-Immersed Transformers and Step-Voltage Regulators*. A 120/240 V, single-phase, pad-mounted transformer with a 50 kVA rated capacity, the most frequently used transformer type within the London Hydro service area, was investigated, using design constants established by the manufacturer as inputs to the model.

The following four scenarios were investigated, based on a typical 24-hour transformer load profile:

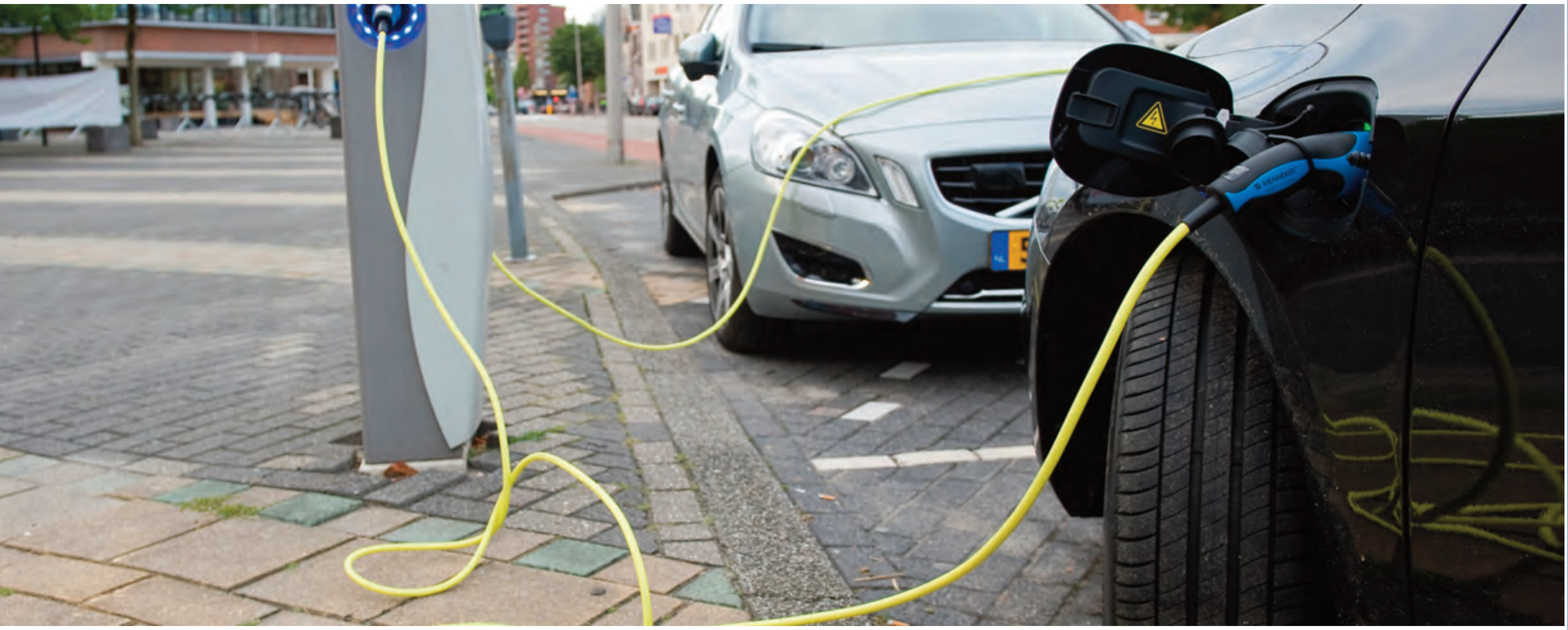
1. **Transformer operating at rated capacity and ambient temperature of 30 °C.**
2. **Transformer operating at rated capacity and ambient temperatures of 20 °C, 25 °C and 30 °C:** For this scenario, ambient temperatures of 20 °C , 25 °C and 30 °C were assigned, with warmer temperatures assigned to daytime hours and slightly cooler temperatures at night, consistent with typical daytime and nighttime temperature fluctuations during the summer peak. The transformer was assumed to be operating at rated capacity (i.e., 1.0) over the 24-hour period.

3. **Transformer operating at half or full rated capacity and ambient temperatures of 20 °C, 25 °C and 30 °C:** This scenario investigated the effects of transformer aging with the transformer loaded at half its rated capacity (i.e., 0.5) during off-peak periods (i.e., between 7 p.m. and 7 a.m.) and loaded at rated capacity (i.e., 1.0) during on-peak periods (i.e., between 7 a.m. and 7 p.m.), while ambient temperatures of 20 °C, 25 °C and 30 °C were assigned, consistent with typical temperature patterns (i.e., lower ambient temperatures at night and higher temperatures during the day).
4. **Transformer operating at half rated capacity, at rated capacity or overloaded and ambient temperatures of 20 °C, 25 °C and 30 °C:** The final scenario investigated a combination of loading at half the transformer's rated capacity (i.e., 0.5), at rated capacity (i.e., 1.0) and overloaded (i.e., 1.1 or 1.2). This scenario was designed to represent the best-case scenario for EV charging, i.e., where drivers would plug in their vehicles overnight when the demand for power is typically lowest. It was assumed that this EV load would overload the transformer at night when temperatures are lower (i.e., during the transformer's cooling cycle); the transformer was assumed to be loaded at either half the rated capacity or at rated capacity during the day when temperatures tend to be higher.

For each of the four scenarios, the effect in years on the lifespan of the transformer's insulation of the conditions described was determined. These findings show that ambient temperature and the load the transformer is carrying could greatly affect the life of its insulation material.

Table 4: Transformer Insulation Life in Years

Transformer loading	1.0	1.0	0.5 or 1.0	0.5, 1.0, 1.1 or 1.2
Ambient temperature over the 24-hour period	30 °C	20 °C, 25 °C and 30 °C	20 °C, 25 °C and 30 °C	20 °C, 25 °C and 30 °C
Calculated insulation life in years	55.13	90.48	262.21	103.73



Summary

The assessment of the electricity distribution system points to some of the key factors that could affect its capacity to accommodate anticipated EV-related loads at the neighbourhood level. The majority of the scenarios investigated show that the system is currently able to support EV-related loading. Variables such as the capacity of the on-board charger, ambient temperature and time of charge all have the potential to impact the system. As such, it will be important to consider these factors in planning and asset management. Technological advances in EV development, such as more powerful on-board chargers and larger overall battery size, must also be factored into planning.

The results of the electricity distribution system assessment demonstrate that, while there are no immediate issues related to the capacity of the distribution system to accommodate EV charging by early adopters, there are conditions under which overloading could occur. These risks can be mitigated through continued monitoring, using information systems already in place at London Hydro (e.g., geographic information systems, smart meters) to avoid ineffective investments in new neighbourhood-level infrastructure, including transformers and secondary cables.

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