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INTERROGATORY 1:

Reference(s): **Exhibit D1, Tab 8, Schedule 12, Appendix A**
Board Decision EB-2009-0139

On page 35 of the Board decision in EB-2009-0139 the Board directed THESL to provide a plan for the incorporation of DG in downtown Toronto. As part of that direction the Board said:

> "The Board has not established an expected time-line for the completion of the DG study. However, it expects that the filed plan will contain, at a minimum, a scope of the work associated with the "next steps" or "alternative approach" and a schedule of key milestones within the plan."

The plan filed in the current application appears to contain the minimum "scope of work" referred to in the excerpt but does not include a schedule of key milestones within the plan.

Does THESL have a schedule of key milestones within the plan? If so please provide it. If not, please explain why it is not available in this application as directed by the Board.

RESPONSE:

Yes. Please see the schedule on page 4 of Exhibit R1, Tab 1, Schedule 3, response to Board Staff interrogatory 3 b).

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INTERROGATORY 2:

Reference(s): Exhibit C1, Tab 4, Schedule 1, Appendix B, page 5

In this business planning document reference is made to an inflation factor to be used in preparing budgets for "direct materials, support and service costs".

a) Please explain why the general CPI inflation factor is appropriate for use in escalating the costs for direct materials, support and service costs.
b) Does THESL consider any industry specific inflation factors that might better reflect cost trends in the distribution business than the CPI?
c) Does THESL conduct any ex post analysis to determine if its forecast of inflation for these goods and services was accurate? If yes, please provide the most recent analysis. If no, please comment on risks of not conducting such analyses.

RESPONSE:

a) THESL believes that general CPI is an appropriate guide for inflation as it is a traditional benchmark for planning purposes.

b) THESL does not directly consider other industry specific factors. Previous year actual costs, test year operational requirements along with general CPI are used to guide the cost estimates for the test year.

c) High level review for total OM&A is undertaken to manage costs within the approved levels. Ex-post analysis is not conducted to determine if forecasted inflation for line items were close to actual inflation. As forecasted CPI is based on assumptions, ex-post analysis may lead to variations that show higher or lower actual costs.

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INTERROGATORY 3:

Reference(s): Exhibit C1, Tab 4, Schedule 1, Appendix B, page 7

Under the Capital Investment Plan section on this page it is noted that:

> "Appropriate justification should be provided for major initiatives."

a) Please elaborate on what constitutes "major initiatives".

b) Please provide any documentation that guides staff on what "appropriate justification" should consist of.

RESPONSE:

a) Major initiatives refer to the larger expenditures THESL needs to make in areas not directly related to the distribution system assets. These initiatives are in the areas of IT, facilities, and fleet.

b) The business units prepare cases to support and justify their respective capital plans. In some cases, such as smart meter implementation, regulatory requirements or direction justify the execution of the activities.

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INTERROGATORY 4:

Reference(s): Exhibit C1, Tab 4, Schedule 1, Appendix B, page 7

Under the Capital Investment Plan section on this page it is noted that:

> "Executives with capital investment budgets will be required to support the proposed initiatives."

a) Please describe the kind of support required for capital investment budgets.

b) Please describe the process used to review the support for capital investment budgets including the approval process.

RESPONSE:

a) Please refer to Exhibit C1, Tab 4, Schedule 1 Appendix A. Business Planning Process memo from the CFO. Specific line items from the Exhibit can be referenced at:

- Page 3, Section 2: "…, THESL's executive management agree on the overall strategy for the next planning horizon (five years) and on the underlying initiatives required to meet the related goals and objectives. THESL executives also ensure that the proposed strategy is aligned with the requirements of the City's Shareholder Direction."
- Page 3, Section 3: "The overall strategy and the underlying goals and objectives of THESL are presented to the Board of Directors by the President and Chief Executive Officer of THC[1] during a strategic session in June."

[1] Please refer to Exhibit R1, Tab 4, Schedule 2 describing the current position and title.

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- Page 6, Section 7: "After completion of the budgeting phase, the CFO and the President and Chief Executive Officer of THC[1] review the financial and operating plans including discussing the related details with the responsible executives. A detailed review is then undertaken by the CFO and the President and Chief Executive Officer of THC[1] to ensure the business plan as presented is aligned with the strategic goals and objectives. Following this review, the business plan and related assumptions will be presented to the President and Chief Executive Officer of THC for final approval. A final business plan is then derived for presentation to and approval by the Board of Directors."

b) Same as (a).

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INTERROGATORY 5:

Reference(s): Exhibit C1, Tab 6, Schedule 1, page 7

This exhibit discusses the asset management model. In the section entitled Feeder Investment Model, reference is made to the optimal timing for asset replacement and the need to quantify the risk cost of a feeder failure. Lines 19-25 describe the process as:

> 19. "In order to quantify the risk due to failure, the FIM requires measures of the probability
> 20. and the consequences of failure for each asset. Consequence costs normally depend on
> 21. the magnitude and duration of customer interruptions. The FIM uses the peak load
> 22. interrupted as a proxy for customer effects. This load, and the duration of the outage are
> 23. converted into implicit dollar costs to customers due to the interruption. Probability of
> 24. failure is estimated based on the age and condition of the asset as measured in the Asset
> 25. Condition Assessment process."

a) Please explain how peak load interrupted in Lines 21-22 is a good proxy for customer effects.
b) Please describe how the duration of the outage in Line 22 is estimated.
c) Please explain how the combined load and duration in Line 22 is converted into implicit dollar costs to customers in Line 23.
d) Please describe how age and condition of the asset in Line 24 is translated into a probability of failure.

RESPONSE:

a) Customer load is a good proxy for customer effects, as it more accurately quantifies the criticality of the customer outage to the utility, factoring in the class of customer (residential, commercial, industrial) and accounting for bulk metered multi-residential accounts (which will only show up as a single customer). Peak loads are applied,

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since the majority of asset failures occur during the peak loading seasons (June, July and August).

b) The outage duration is determined based upon the following parameters:

   i) The type of failed asset.
   ii) The type of asset failure mode.
   iii) The manner in which the asset is configured within the distribution system.
   iv) The process in which the system is restored to its former (pre-outage) state (e.g., replacement of asset).

c) Customer Interruption Costs are defined as a measure of the monetary losses for customers due to an interruption of electric service. The inconvenience and damage encountered by customers involve three periods.

   i) The first period is immediately after power interruption. Customers need to take the necessary action to mitigate the immediate effects of the interruption risks to health and welfare of employees, tenants or the public, production impacts, and other business and non-business activities.
   ii) The second period follows, with on-going disruption to production, sales, office work and entertainment. In this period the customer interruption cost is proportional to the duration of power failure.
   iii) The third period is after the restoration of power when customers take action to resume normal production.

Based upon the principles presented above, a final customer interruption cost can be estimated.

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d) Asset condition and age are translated into a Probability of Failure by employing the use of Hazard Rate Distribution Functions. These are functions that are derived from asset life studies and describe probability of failure as assets age. By utilizing condition information the effective age of an asset can be calculated and its probability of failure more accurately estimated.

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INTERROGATORY 6:

Reference(s): Exhibit C1, Tab 6, Schedule 1, page 11

Line 16 refers to a "Project Equivalence Matrix".

a) Please provide a copy of the document.

b) Please explain in detail how the tradeoff equivalencies in the matrix were arrived at.

RESPONSE:

a) Please see Documentation of the AIS Equivalence Matrix Development, labelled as Appendix A of this Schedule.

b) The process to develop and establish the equivalence matrix included the following steps:

1. Identifying the core business drivers for Toronto Hydro. All value attained in a project will be related to one of the core business drivers.
2. Identifying the elements that drive the evaluation of individual projects and align these to the core business drivers.
3. Selecting key elements that represent the greatest value within each of the core business drivers.
4. Identifying secondary project drivers that provide support to each project. These are collateral benefits to the execution of the project.
5. Comparing the relative value of each of the key elements and secondary elements through a collaborative workshop involving subject matter experts from across all business lines.

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6. Testing these values with a sample portfolio to determine if the assignment of value represents the generally accepted alignment of project values.
7. Modifying and adjusting the equivalence matrix of various elements as determined from the portfolio review.
8. Seek Senior Management approval for the equivalence matrix.

A core team of subject matter experts and stakeholders from different business lines within THESL and DCI Consulting was formed to provide input towards the development of the equivalence matrix. Through several workshops, the core team identified key evaluation elements of projects and valued each element. The workshops performed a group pair-wise comparison across all the business drivers to develop the equivalence matrix. Once the first version of the matrix was complete, 20 test projects were entered into AIS and evaluated using the criteria in the equivalence matrix. The core group reviewed and discussed the results and made adjustments to the matrix to produce the current version of the equivalence matrix.

More details into the development can be found in Documentation of the AIS Equivalence Matrix Development, found at Appendix A to this Schedule.

Documentation of the AIS Equivalence Matrix Development

Background

The equivalence matrix is a representation of the metrics that establish the baseline business evaluation-scoring component in the Asset Investment Strategy (AIS™) modeling environment. This baseline facilitates a transparent and repeatable business case for why an organization should fund a project, or not. Once established, the AIS modeling environment allows an organization to evaluate all projects that the organization is considering for funding using these agreed upon metrics as the drivers of the project business value. Toronto Hydro uses the prioritized portfolio to make funding decisions that best support its business values, as evaluated by the metrics.

Process

The process to develop and establish the equivalence matrix includes the following steps:

1. Identify the core business drivers for Toronto Hydro. All value attained in a project will be related to one of the core business drivers.
2. Identify the elements that drive the evaluation of individual projects and align these to the core business drivers
3. Select key elements that represent the greatest value within each of the core business drivers.
4. Identify secondary project drivers that provide support to each project. These are collateral benefits to the execution of the project.
5. Compare the relative value of each of the key elements and secondary elements through a collaborative workshop involving subject matter experts from across all business lines.
6. Test these values with a sample portfolio to determine if the assignment of value represents the generally accepted alignment of project values
7. Modify and adjust the equivalence matrix of various elements as determined from the portfolio review
8. Seek Senior Management approval for the equivalence matrix

toronto hydro corporation

Business Drivers

Toronto Hydro has four key pillars that guide the decision-making of the delivery business. These are 1) Safety, 2) Customer Experience, 3) Modernization of the Grid, and, 4) Financial.

THESL and DCI formed a core team of subject matter experts to provide input to the development of the equivalence matrix. These core team members represented both the Stations and Distribution business units and included planners that had specific types of projects that they developed. The team identified individual project drivers for each type of work that THESL's Stations and Distribution performs. A project driver is an element that when considered on its own, would help to differentiate two otherwise similar projects. If the subject matter experts determined that an element would differentiate two projects that were otherwise identical, the team included that element in the matrix. These project drivers fit into two general categories:

- Primary Project Drivers – these included such things as added capacity, load at risk to be lost, customer outage experience, replacement of major obsolete equipment, asset condition assessment, a small number of critical infrastructure customers and worker and public safety
- Secondary Project Drivers – these included elements such as increased operability of the electric grid through enhanced switching capability and automation, replacement of minor obsolete equipment, workforce productivity enhancement, community engagement and minor environmental remediation.

The Core Team aligned each primary and secondary project driver to one of the four key business pillars at Toronto Hydro as discussed above. With this, the next step in the process was to establish the relative values of each of the business drivers. Again, the core team of subject matter experts along with the management team participated in a workshop to accomplish this task. The workshop essentially performed a group pair-wise comparison across all of the business drivers to arrive at an overall equivalence matrix. This is a difficult and time-consuming process to compare across 32 different drivers. Below is a description of some of the thought process that went into some key project drivers. Figure 1 depicts the work product Equivalence Matrix from the core team.

Figure 1 - Toronto Hydro Equivalence Matrix

Equivalent Value Representation (Each evaluation produces a Value score of 160,000)	$160,000 in Benefit	107 Momentaries in 12 Months	11,488 Customer Interruption	861,605 Customer Minute Outages	FESI Value of 17*
	18 MW of Distribution Added Capacity	9 MW of Station Added Capacity	11 Station Automated Switching or Control Points	16 Underground Automated Switching or Control Points	32 Overhead Automated Switching or Control Point s
	Addition of 32 Smart Grid or Automation control points	2 Critical Customers	15 Station Manual Switching or Control Points	23 Underground Manual Switching or Control Points	53 Overhead Manual Switching or Control Point s
	768 MW of Station Load Demand at Risk (25% Prob Event * 20% Prob Redundancy Fails)	480 MW of Underground Load Demand at Risk (25% Prob Event * 20% Prob Redundancy Fails)	320 MW of Overhead Load Demand at Risk (100% Prob Event)	32 Obsolete Units of Distribution or Telecom Equipment	16 Obsolete Breakers
	16 Obsolete RTUs	3 Obsolete Switch Batteries	1 Obsolete Switchgear	2 Obsolete Transformers	
Other Evaluations and Value	Rear Lot Facility Eliminated Affecting 0 to 100 Customers (Value = 5,000)	Improves employee efficiency on energized equipment on (Value = 5,000)	A Local Negative Media (Value = 5,000)	Health Index of 66.72 (Value = 5,000)	Project that addresses Asbestos (Value = 10,000)
	Benefit Cost Ratio from FIM of 1.75 (Value = 5,000)	Ability to Recover Service (Value = 20,000)	Pole Relocation Due to Multiple Car Accidents (Value = 5,000)	* **Exponential Function** (FESI 3 = 5,000; FESI 7 = 20,000; FESI 24 = 500,000)	

<u>Capacity Additions</u> – The team considered the relative value of the addition of load serving capacity to the network at the substation level, distribution underground and distribution overhead level. A starting point for the discussion was the relative cost of adding capacity at each of these locations. Substation capacity additions are more costly than distribution underground, which in turn are more costly than distribution overhead. Relative to the business drivers though, the core team agreed that new distribution capacity was valued the same regardless of whether it was overhead or underground. Station capacity was valued higher because it enabled the ability to serve load at the distribution level and provided some backup capacity in the event of equipment failures on the distribution. The team settled on station capacity being valued at two times that of distribution capacity.

Load at Risk – This metric is the amount of load that would be at risk, if a failure event were to occur on the system. Weather, deteriorated equipment and outside intervention such as tree contact of vehicle accidents may be causes of these failure events. Because the substation and distribution network systems have some level of redundancy that the radial distribution systems (overhead and underground) do not have, the core team agreed to value the preservation of load on the radial distribution system at a higher level than load served on substation and network systems. Distribution radial load was valued one and a half times more than the distribution-networked load and almost two and a half times more than substation load. The additional redundancy of the network and substation and the low failure rates and less exposure to external elements in the substation environment were the key decision points for that valuation.

Capacity vs. Load at Risk – Capacity additions were valued much higher than load at risk for a two key reasons. First, the capacity in the system substations and distribution system is critical to serving the customers connected to the Toronto Hydro system. Without capacity, the system cannot serve customers. Secondly, the potential outages to facilities (load at risk) are subject to probabilities of occurrence and variability that effectively devalues that in comparison to the capacity at risk.

Customer Outage Experiences – the number of customer interrupted and the number of customer minutes of interruption that a project is addressing are key differentiators of projects in the Toronto Hydro portfolio. A project that addresses more of these elements is more valuable than one that addresses fewer customer interruptions or minutes of interruptions. The starting baseline for the equivalence matrix workshop was the average Toronto Hydro interruption duration and interruption frequency performance levels applied at the distribution circuit level. The core team determined that the average customer experience on an average circuit (two interruptions a year for 75 minutes average duration) was equivalent to about one MW of new station capacity and two MW of new distribution capacity. The team also evaluated the value of projects that addresses pockets of very poor reliability, beyond the average outages seen by the average Toronto Hydro customers. Work addressing these pockets of customers receives a sliding scale of value based on the relative level of service they are receiving, so that the pockets with the worst reliability receive the most value. The Core Team decided to use a measure of feeders experiencing sustained interruptions (FESI) for this indicator. The Core Team decided to use an exponential function to calculate the business value for the FESI number. For example, a project addressing an area with a FESI value of seven (7) is more than six times more valuable than an area with a FESI value of three (3). A FESI value of 24 is twenty-five times (25) more valuable than a FESI value of seven(7). Thus, projects that address areas of significant concern as measured by the FESI performance get significantly more value as the FESI number rises.

Replacing Obsolete Equipment – With the aging of the utility infrastructure, it is important to replace equipment as it becomes obsolete. Substation equipment in the form of switchgear, transformers and batteries represent the most critical equipment for consideration. Distribution equipment is far less important since its failure will result in dramatically less impact to the customer than failure of critical substation equipment. Toronto Hydro can accomplish repair failures from distribution equipment faster and simpler. The Core Team viewed obsolete switchgear in a substation as the most critical element. It became two times more valuable than a substation transformer, and three times more valuable than the station batteries. The Core Team determined that switchgear was thirty times more valuable to replace than distribution equipment.

System Control Flexibility – The Core Team considered the flexibility in operation of the substation, distribution underground and overhead system to be a valuable business driver. Likewise, the Team compared automated switching to manual switching. The core team compared all of the various options and arrived at the conclusion that:

- Substation switching was about one-and- a-half times (1.5) more valuable than distribution underground and three-and-a-half Times (3.5) more valuable than distribution overhead. The general rationale for this is that substation switching flexibility can enable recovery of more distribution customers during an outage condition. In addition, underground switching is more complex than distribution overhead switching so it has relatively higher value.
- The Core Team considered that having an automated switching or control point was about one-and- a-half times (1.5) more valuable than a manual switching point.

Critical Customers – There are a small number of Toronto Hydro customers that are critical to the community and security of the city and surrounding area. These include facilities such as water treatment facilities, public access systems like 9-1-1 emergency, etc. The core team values projects that directly benefit the level of reliability of service for these customers highly. The team set the value of two critical customers positively impacted by a project to be equivalent to the replacement of one obsolete switchgear installation or to 9MW of added capacity.

Miscellaneous Drivers – There are a number of small project drivers that are minor in comparison to the primary drivers, but they differentiate projects of similar characteristics. Some of these are workforce operations, relocation of poles struck by autos multiple times, service recovery ability and removal of rear lot facilities to name a few. These items are also visible in the Equivalence Matrix in Figure 1.

Summary

The establishment of the equivalence matrix is a complex and time-consuming effort, and is not an exact science. The process does not produce an exacting, high precision, numerically driven outcome. While some of the analysis to support the equivalence matrix is numerically based, the relatively importance of these drivers is best judged by the business professionals who are responsible for the construction, operation and maintenance of the system. The core team that participated in the equivalence matrix workshops and their leadership represents hundreds of years of utility experience and they are intimately familiar with the guiding principles of Toronto Hydro and the needs and expectations of the customers they serve.

The equivalence matrix is a living document, subject to adjustment as times change and the business focus evolves. Establishing this baseline matrix facilitates the transparent and repeatable process that allows Toronto Hydro to evaluate a portfolio of possible funding options, derive a business case value for each project, and create a portfolio of projects that provides the highest value, as defined by the evaluation framework, to Toronto Hydro, subject to any budgetary constraints that it may have.

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INTERROGATORY 7:

Reference(s): Exhibit B1, Tab 13, Schedule 1, page 1

The evidence at Table 1, Service Quality Measures, shows that emergency response in 2009 was 79.5%.

a) Please explain what caused Emergency Response to drop below the OEB Standard and be substantially lower than in previous years as shown in the table.

b) Does THESL plan to take any actions to improve its emergency response in 2010? If yes, what specifically? If not, please explain why not.

RESPONSE:

a) and b) Please see the response to Board Staff interrogatory 5.

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INTERROGATORY 8:

Reference(s): Exhibit B 1, Tab 14, Schedule 1, page 6

Two out of three major reliability indicators got worse in 2009 compare to 2008. Moreover, CAIDI performance in 2009 is far worse than in any of the other years presented.

What basis do you use when you say, in the following quotation, that system reliability performance has shown improvement between 2008 and 2009?

> "Generally, system reliability performance has shown improvement between 2008 and 2009, some of which may be attributed to THESL's investment programs."

RESPONSE:

SAIFI improved for defective equipment, adverse environment and human element. This indicates fewer customers interrupted due to each cause as a result of increased robustness of the distribution system. SAIDI improved for tree contacts, adverse environment and human element. SAIDI deteriorated slightly for defective equipment and significantly for loss of supply. CAIDI is a function of SAIDI and SAIFI, specifically SAIDI divided by SAIFI. Since SAIFI is the denominator in the equation, as it improves (gets smaller) then CAIDI will appear to deteriorate unless SAIDI improves in similar proportion. Overall, the phrase "generally system reliability performance has shown improvement" is referring to the SAIDI and SAIFI impact of forced outages excluding loss of supply where SAIFI has clearly improved and SAIDI has remained stable.

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INTERROGATORY 9:

Reference(s): Exhibit B 1, Tab 14, Schedule 1, page 11

Chart 8 shows substantially higher equipment failures of overhead lightning arresters and insulators in 2009 compared to previous years.

a) Please explain why this is the case.

b) In addition, transformer failures in 2009 were almost twice the number of failures in 2008. Please elaborate on this.

RESPONSE:

a) Excluding major event days (MEDs) the number of customers interrupted (CI) in 2009 due to porcelain insulators increased by 42,713 from 2008 numbers. In 2009, the number of customers interrupted (CI) by lightning arrester failures actually decreased by 16,843 from 2008 numbers. The reason for the increase in insulator failures is that they are nearing end-of-life. Consequently, the number of insulator failures will continue to increase until all of the porcelain insulators have been replaced.

b) Overhead transformers within the THESL distribution system can be broken down into two main categories: either the transformer is completely self protected (CSP) or not (non-CSP). The vast majority of CSP-type transformers existing in the system are either at end of serviceable life or beyond. Consequently, the CI impact of CSP transformers had increased rapidly (see table below). It is for this reason that money has also been allocated under the Standardization Portfolio to eliminate CSP transformers from the system.

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	2008	2009	2010 Year To Date
CI from O/H Transformers	5,511	11,273	9,682
CI from CSP Transformers	1,998	6,810	9,051
CI from CSP transformers as %	36%	60%	93%

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INTERROGATORY 10:

Reference(s): Exhibit B 1, Tab 14, Schedule 1, page 15, Lines 12-17

> "In 2008, Toronto Hydro adopted and implemented a reliability-based tree trimming program. It is a departure from the traditional fixed area and cycle approach. The new methodology takes into consideration reliability performance of each feeder from tree-related outages as well as the cost of trimming around each feeder. The analysis yields a trimming cycle for each feeder that will deliver the optimum reliability performance for the amount of resource spent."

Please explain how THESL identifies optimum reliability performance.

RESPONSE:

Optimum reliability performance refers to the point where increased intervention expenditures become greater than the total customer interruption costs avoided.

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INTERROGATORY 11:

Reference(s): Exhibit B 1, Tab 14, Schedule 1, page 17

Chart 13 provides data of foreign interference CHI (customer hours interrupted) performance between 2005 and 2009.

Please explain and provide details about the causes of increased CHI for all four categories of foreign interference from 2008 to 2009.

RESPONSE:

Foreign interference is broken down into four different categories:

1) Dig-in – From 2008 to 2009, the number of dig-ins have increased by 80% and the CHI has increased at the same rate.
2) Other – This category involves Contractor interference, Member of Public, Customer-Owned Equipment and Foreign Objects. From 2008 to 2009, the greatest increase is due to non-Toronto Hydro employee interference. In 2008 incidences were localized to small areas while in 2009, a large amount of customers were affected. This increased CHI significantly.
3) Vehicle – From 2008 to 2009, the number of vehicle incident-related CHI has increased by 46%. Restoration time from 2008 to 2009 increased from 0.65 hours to 1.19 hours.
4) Animal Contact – From 2008 to 2009, the number of animal contacts increased by 3% and a small increase in CHI is observed.

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INTERROGATORY 12:

Reference(s): Exhibit F1, Tab 1, Schedule 1

Table 1 on Page 1 of the schedule shows 2010 O&M spending of $179.6 M. The Settlement Agreement in EB-2009-0139 resulted in an OM&A component of revenue requirement of $195.4 M plus property taxes and Ontario Capital tax.

Please identify what part of the $195.4 M should be compared to the forecast 2010 O&M expenditure of $179.6M.

RESPONSE:

The O&M portion of the OM&A settlement amount of $195.4M was not specifically agreed upon so there is no direct settlement O&M comparator. However, the 2010 filed OM&A was $220.9M including $8.7M property taxes and capital taxes; the O&M component was $187.6M. Applying the ratio of filed O&M to filed OM&A minus property taxes [187.6/(222.9-8.7)] to the settlement OM&A amount yields an estimated O&M component of about $172.7M.

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INTERROGATORY 13:

Reference(s): Exhibit F1, Tab 1, Schedule 2

Lines 1-6 on Page 5 note that 2009 historical costs have increased due to "the apprentice training costs being added to the maintenance program".

a) Please explain where apprentice costs were previously charged.
b) Please explain what these costs were for.
c) Please explain why those costs were transferred to the preventive maintenance program.
d) Do the 2010 and 2011 totals for preventive maintenance also include apprentice costs transferred from another account? If yes, please provide the estimated costs for apprentices.

RESPONSE:

a) All apprentice costs resided in the Trades Training Department until 2009 when the decision was made to place apprentices into the operating departments. Currently apprentices only reside in the Trades Training Department during their initial training or entry level core training program. After that program is complete their costs are transferred to the department where they are placed for the current year. Apprentices are rotated through the work centers and departments during their 54-month apprenticeship. Their core training courses are still charged to the Trades Training Department. All other costs are budgeted and captured in their respective operations department.

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b) These costs represent the loss in productivity that THESL absorbs as the apprentices observe training staff perform the maintenance activities. These costs also represent the additional time required for apprentices to perform these same activities and achieve competence.

c) Apprentice training costs within operations departments were previously charged exclusively to capital projects. Capital rebuild projects provide an ideal training ground for the developing trades staff. With the continuing development of the trades training programs THESL introduced maintenance operations into the training curriculum to ensure complete exposure with trades practices. These costs were transferred to the preventive maintenance program to align with the activities where these costs are incurred.

d) The preventive maintenance program budgets do not include apprentice costs transferred in from another account. The budgeted costs include only adjustments for production inefficiencies associated with apprentice work.

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INTERROGATORY 14:

Reference(s): Exhibit F1, Tab 1, Schedule 3

Page 7 of the schedule attributes $0.7 M of increased preventive maintenance spending from 2009 to 2010 to increased tree trimming.

a) Does the 2011 forecast of $12.0 M also include an increased amount for tree trimming? If yes, please identify how much the additional tree trimming costs will be.

b) Does THESL anticipate ongoing increased costs for tree trimming over historical? If yes, please elaborate on how much is expected over historical cost.

c) Does THESL have a study of vegetation management that resulted in the decision to increase tree trimming? If yes, please provide it. If no, what was the basis for the decision to increase tree trimming?

RESPONSE:

a) Yes, it included additional spending for tree trimming. The additional forecasted spending in tree trimming is $0.25 million for spot tree trimming to prevent further tree related outages.

b) THESL has adopted a reliability-based tree trimming model for the vegetation management program. This program utilizes the historical tree related reliability statistics along with the cost of trimming to produce an optimal annual tree trimming program. As this is a dynamic model that is dependant on actual reliability performance, the annual tree trimming budget will also vary.

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c) See response to part b) above.

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INTERROGATORY 15:

Reference(s): Exhibit F1, Tab 1, Schedule 4

Table 1 on Page 7 shows predictive maintenance increasing from $1.3 M in 2008 to $6.2 M in 2011. Most of this is attributed to the contact voltage scanning program which is expected to cost $4.4 M in 2011.

a) Does THESL anticipate continuing to spend at the 2011 level for scanning in future years?

b) If yes, has it considered acquiring the equipment and training to conduct the scanning itself? If no, please explain why this would not be a cost effective alternative to contracting the service.

c) Has THESL conducted a cost/benefit analysis of the scanning program for 2009 and 2010? If yes, please provide the analysis. If no, please explain how THESL determines it is receiving value for the cost of the program?

RESPONSE:

a) Yes, THESL anticipates continuing to spend at the 2011 level for scanning in the short term as the secondary systems are being upgraded, these costs will remain consistent unless competition emerges in this market. In the longer term, THESL will re-evaluate the frequency of scanning based on experience, number of incidents and secondary asset condition improvement.

b) THESL has considered acquiring the equipment and training to conduct scanning ourselves but due to the proprietary nature of the scanning and detection technology, Power Survey Company (“PSC”) will not negotiate any Non Disclosure Agreement

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and permit the technology transfer and is not currently inclined to sell this technology to the open market.

c) No, THESL has not prepared a formal cost-benefit analysis in support of this program. Our determination of program value is based on the ability of PSC teams to effectively scan the 630 km^2 for the presence of contact voltage on accessible surfaces. The resources and costs required to scan each unique surface over a 630 km^2 area using manual test equipment will far exceed the PSC scanning method. During the Level III emergency when PSC was engaged for their services, it was clearly demonstrated that this was an effective methodology. In the first city-wide scan, a total of 221 sources of contact voltage were identified and consequently repaired. PSC has been conducting contact voltage scans successfully for major cities in the United States, including New York City for Con Edison. They have proprietary technology that has been proven in the field to be effective and efficient in identifying locations where contact voltage is present. Their scanning method was found to be much more effective and efficient at identifying the source of contact voltage compared to manual examination of each electrical structure on the street and sidewalks. THESL has engaged the PSC to perform regularly scheduled contact voltage scans in 2010 with satisfactory results, the contract will continue for 2011. PSC holds the patent to this scanning technology and there is no comparable technology available in the marketplace. The PSC's cost was evaluated and found to be reasonable.

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INTERROGATORY 16:

Reference(s): Exhibit F1, Tab 1, Schedule 4

On page 7 of the schedule reference is made to the “success of contact voltage scan program in detecting potential electrical hazards on Toronto roads in 2009 and 2010”.

Please provide details of the potential electrical hazards discovered through the scanning program after the initial emergency condition in 2009 was dealt with.

RESPONSE:

In 2009 in the first city wide scan, a total of 221 sources of contact voltage were identified and repaired. The voltage levels varied from as high as 120 volts to as low as 1 volt. The contact voltage sources were found in handwells, poles and other non-THESL structures.

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INTERROGATORY 17

Reference(s): Exhibit F1, Tab 2, Schedule 1

Table 1 on Page 3 shows an increase in equipment service costs of $2.0 M or approximately 21%. This is attributed to "increases in payroll, payroll benefits, vehicle fuel and vehicle insurance".

a) Please breakdown the increase of $2.0 M into individual amounts for payroll, payroll benefits, vehicle fuel and vehicle insurance.

b) Please explain why these otherwise routine categories of cost should increase by such a dramatic amount.

RESPONSE:

a)

Payroll	0.2
Payroll Benefits	0.1
Labour costs	0.4
Vehicle Fuel	0.0
Vehicle Insurance	-0.1
Purchased Services	0.4
Occupancy Charges	1.0
Total	2.0

b) The explanation for cost increases in O&M programs are explained, in detail, in Exhibit F1, Tab 1, Schedules 3-6.

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INTERROGATORY 18

Reference(s): **Exhibit F1, Tab 4, Schedule 1, page 5**
Exhibit C2, Tab 3, Schedule 2, page 3

Page 5 of F1-4-1 shows total supply chain costs increasing from $9.3 M in 2010 to $11.4 M in 2011 or approximately 23%. At the same time Table 1 on page 3 of C2-3-2 shows total materials inventory declining from $94.6 M in 2010 to $88.3 M in 2011.

Please explain why additional manpower is needed as referred to in line 9 on page 5 of F1-4-1 if the amount of material requiring managing is declining.

RESPONSE:

The increase of Supply Chain costs associated with manpower is being incurred to drive improvement of service levels provided to field crews. In particular this service level increase is aimed at better response to reactive and emergency demand.

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INTERROGATORY 19

Reference(s): **Exhibit F1, Tab 4, Schedule 1, page 6**
Exhibit C2, Tab 3, Schedule 2, page 3

Table 2 on page 6 of F1-4-1 shows the on-cost rate applied to material issues increasing from 12% in 2010 to 17% in 2011 while total material inventory is only declining from $94.6 M in 2010 to $88.3 M in 2011, a drop of only about 7%.

a) Please explain why the on-cost rate should increase by about 42% when the material needing management only drops by about 7%.
b) Lines 1-2 on Page 6 of F1-4-1 states that “the on-cost rate will revert back to 17% in 2011 while the rates for historical years was never higher than 14%. Please explain the use of the term “revert” in this context.
c) The 2008 and 2009 on-cost rates were 11% and 14% respectively on materials of about $64 M. Please explain why the on-cost rate for 2011 should be so much higher at 17% when it is spread over $88.3 M in materials.

RESPONSE:

a) The increase of the on-cost rate is disproportionate to the reduction of materials inventory for 2011 which has dropped, in part, due to further outsourcing of capital work. Incremental headcount is now being focussed on driving further improvement to customer service.

b) This is a typographical error. The statement should read: “…the on-cost rate will increase to 17 percent in 2011”.

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c) The on-cost rate of 17% is relatively higher than the previous two years due to the incremental head count added to better service emergency and reactive field crews.

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INTERROGATORY 20

Reference(s): Exhibit F2, Tab 5, Schedule 1

Table 4 on Page 5 of the schedule shows an increase in costs for external reporting from $2.3 M in 2010 to $5.5 M in 2011. This is attributed to costs to meet dual accounting standards related to IFRS that have been included in the 2011 numbers.

Does THESL anticipate that costs for external reporting in future years will revert to historical levels? If not, please explain why costs will remain higher than historical.

RESPONSE:

THESL does not anticipate the costs for external reporting in future years will fully revert to historical levels. Once IFRS is implemented, there will continue to be costs in excess of historical, due to:

1) The significant increase in the Corporation's financial statement disclosure requirements resulting from the adoption of IFRS (Exhibit Q1, Tab 1, Schedule 1, page 4).
2) Changes to accounting policies that will result in additional controls and procedures to address reporting on translation date as well as IFRS reporting requirements (Exhibit Q1, Tab 1, Schedule 1, page 5).

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INTERROGATORY 21

Reference(s): Exhibit F2, Tab 7, Schedule 1

Table 1 on Page 2 of the schedule shows legal costs increasing from $2.9 M in 2009 to $4.5 M in 2010 and to $5.0 M in 2011. The increase in 2010 is attributed to "$1.5 million of legal service costs related to corporate governance, policy and finance were transferred from Toronto Hydro Corporation to THESL." The increase in 2011 is attributed to "Wage increases, additional employees to meet increased workload, and general inflation account for the increase in the test year costs."

a) Please explain what these costs were for and why THC transferred them to THESL.
b) Was this a one time only transfer or is the additional $1.5 M in costs an ongoing expense?
c) For the 2011 increase please elaborate on the need for additional employees and quantify the contribution made by wage increases and general inflation to the increase.

RESPONSE:

a) The costs relate to employees and activities in the reference area that were transferred due to the restructuring of THESL and THC. Please see Exhibit R1, Tab 11, Schedule 21 (response for VECC Interrogatory 21).

b) This is not a one-time transfer.

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c) Staffing increase required to manage increased litigation and regulatory workload. The increase in payroll due to wage increase is $0.1M.

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INTERROGATORY 22

Reference(s): Exhibit C2, Tab 1, Schedule 2

This exhibit discusses compensation.

Lines 19-21 refer to the attractiveness of THESL's apprentices and Trade School graduates to other utilities.

a) What percentage of THESL apprentices in the trades training program are hired away by other utilities during the four year apprenticeship period?
b) What percentage of graduates from the Trades School are hired away by other utilities within two years of graduation?
c) Does THESL have an estimate of how many years an employee needs to work for it to fully recover the cost of training through the Trades School? If yes, please describe the estimating process and outcome.
d) Has THESL considered implementing a deposit system for apprentices that would be forfeited to the company if the apprentice leaves employment for another employer within the cost recovery period referred to in c) above? Please comment on the pros and cons of such a disincentive system.

RESPONSE:

a) Approximately 3% of THESL's apprentices have been hired away by other utilities during their apprenticeship from 2003 to 2009.

b) 0%

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c) The apprentice's contribution to productivity is very low in the first two years of employment and gradually increases over the last two years of the program when they attain journeyperson status. After a nine-year period, the company will have recovered the cost of training an employee.

d) THESL has not implemented a deposit system; however, the letter of employment for apprentices stipulates that they reimburse THESL for a percentage of training costs if they resign before nine years of employment has been completed.

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INTERROGATORY 23

Reference(s): **Exhibit C2, Tab 1, Schedule 2**

Lines 1-2 on Page 2 of the exhibit state that:

> "The goal of THESL's overall compensation strategy is to secure a workforce that is skilled and capable of exceptional performance and commitment."

a) Does this strategy apply to all employee groups or just to managerial and executive groups?

b) Does this objective result in THESL having to provide an exceptional compensation plan relative to other competing employers?

RESPONSE:

a) Yes, the goal of THESL's overall compensation strategy does apply to all employee groups at Toronto Hydro.

b) It is not THESL's objective to have an "exceptional compensation plan relative to other competing employers" but to provide a compensation program that is performance-based and competitive in the markets where Toronto Hydro competes for talent.

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INTERROGATORY 24:

Reference(s): Exhibit C2, Tab 1, Schedule 2

Line 18 on Page 3 refers to benchmarking studies for compensation plans.

a) Do these benchmarking studies apply to employees in each of the CUPE, Society and Managerial/Executive groups?

b) Please provide a copy of the most recent benchmarking study applicable to each of the groups above.

RESPONSE:

a) The benchmarking studies discussed on line 18 on page 3 apply to the non-union, managerial, and executive employee groups.

b) THESL participates annually in a number of salary surveys to review the market competitiveness of our job rates. THESL also participates in a number of salary planning surveys to forecast base salary policy movement. The salary surveys that THESL uses for benchmarking purposes cannot be disclosed as THESL has signed a non-disclosure agreement with each of the survey companies. Disclosure would involve information provided by other companies on a confidential basis.

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INTERROGATORY 25:

Reference(s): Exhibit C2, Tab 1, Schedule 5

This schedule discusses the workforce staffing plan. On Page 3 reference is made to THESL's workforce demographic profile.

a) Please provide demographic profiles for each of CUPE represented, Society represented and Managerial and Executive categories of employees.

b) Please provide an expanded table 1 at the bottom of page 3 to show actual retirements for the years 2007-2009.

c) Does THESL hire retirees back on a contract basis?

d) If yes, how many such reemployed retirees has THESL had on average for the past 3 years?

e) If no, please explain why THESL does not hire retirees back on contract.

RESPONSE:

a) Average Age by Employee Category

Employee Category	Average Age
Executive	50
Managerial	49
Non-Union	44
Society	42
Union	49
Total Organization	48

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b) Actual Retirements

Year	2007 Actual	2008 Actual	2009 Actual
Number of Retirements	19	16	30

Year	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Number of retirements	64	37	50	55	79	68	97	103	89	112

c) Yes.

d) Over the two years period in 2009 and 2010, THESL hired nine retirees.

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INTERROGATORY 26:

Reference(s): Exhibit C2, Tab 1, Schedule 5

On Page 5 a discussion of Value to the Customer is presented and the following statement appears:

> "Heightened service expectations, increasingly a market norm, will require innovative technologies that deploy real-time information or alerts and 24/7customer service options, with access to highly knowledgeable staff who can translate complex billing data into sound analysis and advise on energy programs to assist the customer."

a) "heightened service expectations" are "increasingly a market norm". Does THESL have any studies that support this conclusion? If so, please provide them. If not, please explain the basis for the conclusion.

b) Please describe the innovative technologies that deploy real-time information or alerts.

c) What customer service options does THESL anticipate will be needed on a 24/7 basis?

d) Does THESL anticipate that access to highly knowledgeable staff who can translate complex billing data into sound analysis and advise on energy programs will be needed on a 24/7 basis? If yes, please provide any evidence that supports that conclusion.

e) Does THESL currently provide any of the customer services referenced in the excerpt? If yes, please describe and comment on what additional services will be needed.

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RESPONSE:

a) THESL has not done a specific study. However, THESL has based this conclusion from substantial media attention, energy, conservation and customer service conferences, industry publications, anecdotal evidence from customer enquiries, comparisons with other industry best practices, the shift to a 24/7 society, government initiatives and regulatory direction (Green Energy Act, Smart Meters).

b) Real time information or alerts could be deployed through web applications, mobile applications, and Interactive Voice Response (IVR) system applications

c) THESL anticipates that, through technology-based applications, customers would want 24/7 access to their consumption, account and billing information as well as transactional interactions such as the ability to make bill payments, update their profile, open and close accounts, print reports, and set-up appointments. In addition, customers may want access general information about rates, energy and conservation programs.

d) No.

e) Yes, THESL currently provides some of the services referenced in the excerpt. Additionally, THESL will need customer self-serve web applications, and enhanced self-serve IVR offerings.

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INTERROGATORY 27:

Reference(s): **Exhibit C2, Tab 1, Schedule 5**

At Lines 14-17 on Page 5 the following statement appears:

> "Customer service employees will need to be equipped to offer a wide spectrum of services from answering bill enquiries to providing advice and guidance on energy consumption management and various program offerings."

a) Does THESL currently provide services for bill enquiries and advice and guidance on energy consumption? If yes, please comment on the need to expand these services. If no, where do customers currently get assistance for these matters?

b) Please elaborate on what makes up "various program offerings". Are these new programs or existing ones?

RESPONSE:

a) Yes, THESL currently provides these services. The greater awareness of energy consumption and conservation is adding pressure to Customer Services to provide a wider range of information. As the energy market evolves with the *Green Energy Act*, Smart Grid, and Time-of-Use rates, in-depth training and knowledge requirements will increase.

b) The various offerings are made up of programs that support customers to shift usage from peak periods, educate customers on conservation and demand management and control electricity usage.

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INTERROGATORY 28:

Reference(s): **Exhibit C2, Tab 1, Schedule 5**

At Lines 23-24 on Page 5 reference is made to the need to support "value-added customer services and technologies such as Smart Metering and web-based services…"

a) Please describe the support needed for Smart Metering in the customer service context.

b) Please describe the web based services referred to.

c) Does THESL provide web based services through its own staff or does it contract this work out?

RESPONSE:

a) Smart Metering and Time-of-Use billing require technology and data management support to operate, manage, and validate systems and billing data. The added complexity inherent in Time-of-Use billing requires highly knowledgeable staff with the ability to translate and communicate effectively with customers.

b) THESL offers a Time-of-Use web tool that provides customers visibility into their energy use by hour, day, month and year. This allows customers to proactively manage their electricity consumption and see the effects of load shifting and conservation efforts.

c) A mixture of both.

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INTERROGATORY 29:

Reference(s): Exhibit C2, Tab 1, Schedule 5

At Lines 25-27 on Page 5 reference is made to the need for "extensive training for harmonized jobs of broader scope".

a) Please explain what THESL means by harmonized jobs of broader scope.

b) What is driving the need for such jobs?

c) How much does THESL expect to spend annually on training for these jobs?

RESPONSE:

a) Harmonized jobs of broader scope means two or more individual job classifications have been combined into one job classification. Harmonized jobs enable one employee to perform the same scope of work or range of tasks that previously would have required additional employees whose scope or range of tasks was limited to a single job classification. For example, under the previous job classification system, only certain cable workers could work in a cable chamber, but they were restricted from doing similar work in a cable vault. That meant two workers had to be available for a job involving a cable chamber and a cable vault even if the actual work being done in the two places was identical.

b) The drivers for such jobs include:

- Improving the efficiency of work processes, e.g., reducing the complexity and idle time associated with hand-offs;
- Improving the distribution of work and utilization of resources by not stranding resources when there is insufficient work of a specific and specialized nature;

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- Making training more efficient (fewer roles require fewer trainers);
- Creating greater development opportunities offering more interesting, multi-skilled work for employees previously limited by restrictive job classifications; and
- Enhancing attraction and retention by offering jobs of greater depth and breadth that support continuous learning and opportunities for career advancement.

c) Majority of the training for harmonized jobs is conducted in house. External training for harmonization jobs is a one-time spend.

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INTERROGATORY 30:

Reference(s): Exhibit C2, Tab 1, Schedule 5

At Lines 18-23 on Page 6 reference is made to contract resources to assist in meeting the capital program requirements.

a) As a percentage of the total 2011 capital program how much work will be done by these design build contractors?

b) How much is projected to be done by contractors in 2010?

c) Has THESL conducted a comparison of the costs of contracting this work as opposed to doing it with in house resources? If yes, please provide a synopsis of the comparison.

RESPONSE:

a) The design build contractors will be doing approximately 26% of the 2011 capital program.

b) The design build contractors are projected to do 29% of the 2010 capital program.

c) As part of the competitive selection process, THESL evaluated the cost impacts of each bidder. The analysis showed that the costs of contracting capital design, electrical and civil work in aggregate to be slightly higher than internal costs.

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INTERROGATORY 31:

Reference(s): Exhibit C2, Tab 1, Schedule 5

Starting on Page 7 of the schedule, a discussion of Trades and Technical jobs is presented.

a) Has THESL experienced any difficulties attracting apprentices to its program? If yes, please explain what the difficulties have been due to and what actions THESL is taking to overcome them.

b) Does THESL have a program to raise awareness in high schools for trades and technical jobs? If yes, please provide a synopsis of the program and the results to date. If no, please explain why such a program would not be a good idea.

RESPONSE:

a) No. THESL has not had difficulty attracting candidates that meet the minimum requirements to the apprenticeship programs; however, few candidates are applying that have a background or certification in electricity. In the most recent overhead and underground apprenticeship recruitment processes, THESL has had between 500-600 applicants per posting.

b) Yes. Toronto Hydro has targeted initiatives to raise awareness in high schools for trades and technical jobs. Activities include:

   1) Partnership with Georgian College: Plans for 2011 include joint “road shows” and “open houses” at Greater Toronto Area high schools. Some program curriculum will be specifically designed to support pre-requisite entry to Toronto Hydro roles.

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2) Trades School Open House: Host open houses at the Trades School to attract local talent. Targeted advertising to high schools (Toronto District and Toronto Catholic District), technical schools, YMCA, employment agencies and community colleges, upwards of 450 participants in attendance.
3) Participate in Take your Kids to Work Day: In 2010, over 100 Grade 9 students participated in the full-day program.
4) Participation in annual Toronto Hydro Day: Showcase of Toronto Hydro in downtown Toronto location (Dundas Square). Talent Management booth showcased full range of employment opportunities, including trades and technical positions.
5) Support of High School Community Volunteerism: High school students are able to achieve mandatory volunteerism hours by working at Toronto Hydro sponsored community events. This provides high school students an informal introduction to utility industry careers, by networking and interacting with employees.

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INTERROGATORY 32:

Reference(s): Exhibit C2, Tab 1, Schedule 5

Starting at Line 15 on Page 8 of the schedule a discussion of the trades training school at THESL is presented.

a) Please provide a table showing the annual number of entrants to the program from its inception in 2003 to date along with the number who completed the program and the number who left the program during each period for other reasons.

b) Table 2 on Page 9 notes only 2 graduates from the program in 2009, 13 in 2010 and 17 in 2011. Please explain why so few program participants are expected to graduate and reconcile it with the statements at Lines 18-20 on Page 8 that "Twenty percent of these apprentices have graduated to date and remain with THESL. Over 89 percent of apprentices have continued in the program."

RESPONSE:

a)

Year	Number of Entrants	Graduates	Left Program
2003	16	1 -2006 2-2007 11-2008	2
2004	12	1-2007 8-2008	3
2005	1	1-2008	
2006	18		4
2007	37		4
2008	29		2
2009	13		1

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b) The apprenticeship program is a 54-month program. Twenty-nine apprentices were due to graduate from the classes hired from 2003 to 2005: 24 have graduated and five left the program. To date, 19% of the total 126 entrants to the program have graduated; another 75 are expected to graduate by 2014.

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INTERROGATORY 33:

Reference(s): Exhibit C2, Tab 1, Schedule 6 – Gain Sharing Program Guide

Page 3 discusses eligibility for the gain sharing program.

a) Please explain what Crew Leaders are responsible for.

b) How many Crew Leaders does THESL currently employee?

c) Please explain what System Response Representatives are responsible for.

d) How many System Response Representatives does THESL currently employ?

e) Please explain why the program is restricted to these two categories of employees.

f) Does THESL intend to expand this system to other employees? If so, please describe when and to what employees the program will apply.

RESPONSE:

a) Crew Leaders are responsible for site supervision, overseeing the crews and ensuring execution of daily work plans in an effective, efficient and safe manner. They also facilitate team communication, encourage attendance and liaise with customers.

b) Currently there are 84 Crew Leaders in THESL.

c) System Response Representatives provide 24-hour system response to planned and unplanned works, ensuring efficient and safe services are provided to customers by providing site supervision to crews. They also facilitate team communication, encourage attendance and liaise with customers.

d) Currently there are 39 System Response Representatives in THESL.

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e) The Gainsharing program was a negotiated settlement and was the first time a performance-based pay program was introduced into the Collective Agreement. These positions were selected because they are the most senior and influential within the Union.

f) THESL does not intend to expand this program to other employees at this point in time.

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INTERROGATORY 34:

Reference(s): **Exhibit C2, Tab 1, Schedule 6 – Gain Sharing Program Guide**

a) Please provide a chart similar to the Sample 2010 Gain Sharing Results on Page 6 results showing the target and actual results for the 2009 program.

b) Please compare the results for 2009 against historical performance of the KPI in the three year period prior to the establishment of the gain sharing plan.

c) How much was the payout under the Gain Sharing plan for 2009?

RESPONSE:

a) **2009 Gain Sharing Program Results:**

K.P.I.	Weight	Target	Result	Payout
Safety - My Goal Is Zero				
Reduce Injuries *(%of FTEs)*	25%	94%	95%	25%
Attendance				
Attendance - avg. # days absent *(total absences/total FTEs)*	25%	9.25 days	8.6 days	25%
Modernization				
Distribution Plant Capital per unit ($K/unit)	25%	$0.90K	$0.85K	25%
Customer Service				
SAIDI *(Min)*	25%	84.0 min	82.6 min	25%
TOTAL PAYOUT				100%

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b) Historical KPI Performance: Below are Corporate KPI targets and results where available. The remaining KPIs are not comparable due to variations in definitions from year-to-year or they were not measured at the Corporate level.

	2006		2007		2008	
K.P.I.	Target	Result	Target	Result	Target	Result
Safety - My Goal Is Zero						
Reduce Injuries *(%of FTEs)*			94%	93%	**94%**	**94.6%**
Attendance						
Attendance - avg. # days absent *(total absences/total FTEs)*						
Modernization						
Distribution Plant Capital per unit ($K/unit)			$1.25	$0.93K	$1.00K	$0.83K
Customer Service						
SAIDI *(Min)*			78 min	81 min	85 min	74.5 min

c) Payout under the 2009 gain sharing program was $251,521.40.

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INTERROGATORY 35:

Reference(s): Exhibit D1, Tab 8, Schedule 1, page 4

This schedule refers to a "Reliability Peer Group Study" performed by Capgemini for THESL in 2009.

a) Please provide a copy of the study.

b) Please explain why THESL decided to compare itself to the selected international peer group rather than other Ontario distributors.

c) Please provide a comparison of THESL reliability to that of other Ontario distributors.

RESPONSE:

a) Please see Appendix A to this Schedule for the document "Reliability Peer Group Study".

b) The City of Toronto is the economic capital of Canada (which is part of the G8 World Economic Powers). This prompted THESL to compare itself to an international peer group at similar level.

c) Please see pages 69-81 of the "2009 Yearbook of Electricity Distributors" for a comparison of THESL's reliability to that of other Ontario Distributors. This is provided at Appendix B to this Schedule.

RELIABILITY PEER GROUP CITIES COMPARISON

FINAL REPORT
(NOVEMBER 2009)

TOGETHER. FREE YOUR ENERGIES

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1. EXECUTIVE SUMMARY

Toronto is recognized as a world financial center and also both as a business center and tourist destination. However, it does not have the electric reliability of a major financial center, limiting its potential growth. In fact, its' System Average Interruption Duration Index (SAIDI) IEEE reliability metric is at least double or more, than that of a peer group of financial center cities. This is could be a strong disincentive to financial institutions looking for a North American hub..

Maintaining and enhancing the electrical network reliability is a critical element of Toronto Hydro's efforts to provide both quality and dependable electrical service to its customers. It is also a key element in meeting the challenges of environmental sustainability through the development and addition of renewable and distributed generation sources. The province of Ontario has been very aggressive, both legislatively and regulatory, on providing for environmental sustainability. Improving reliability is typically an asset/infrastructure-intensive effort, requiring significant capital investment. The success of these investments and related efforts are primarily measured through SAIDI, the average electrical outage time experienced by each customer served and the System Average Interruption Frequency Index (SAIFI), the average number of interruptions that each customer served experiences. Toronto Hydro's 2008 SAIDI and SAIFI are 74.5 minutes and 1.80,respectively. Companies looking to locate in financial centers require the absolute minimum disruption in electrical power and look to cities where this is provided. Companies may also consider moving to other financial districts if the power quality and dependability becomes unacceptable.

There is a balance between the amount of capital investment made and the achievement of lower SAIDI and SAIFI numbers that Toronto Hydro must achieve. There are examples, like for the city of Tokyo, that has an annual SAIDI of under two minutes, but that was achieved through almost a complete rebuild of their electrical network in the early- to mid-1980's at a cost of about $3000 US per customer account (that is more than $6000 in today's value). This initiative was undertaken primarily by the Japanese government as means to recover from the 1980's economic recession. Clearly, the capital investment needed to achieve this SAIDI is outside the norm expected of a Utility or the level of reliability expected by most customers. As is identified in this report, for several of the other cities to which reliability comparisons were made, the initial design or redesign of their electrical networks was driven by factors that allowed for massive amounts of capital infrastructure investment, resulting in high electric network reliability.

Toronto Hydro, however, can benefit from evaluating electrical network reliability improvement efforts undertaken in similar (peer group) cities. It's an opportunity to evaluate the reliability improvement decisions made by other utilities, and in some cases, be able to access the results. It also provides an opportunity to evaluate the impact on reliability resulting from various electric network designs. This effort identifies "like" cities (not utilities) for Toronto Hydro to compare against using mutually agreed upon parameters. The results can be used to establish achievable reliability targets and identify the potential required projects/investments to achieve performance consistent with the selected peer group cities reliability. As part of this effort, Toronto Hydro's current 10-year reliability plan was evaluated against the selected peer group cities to identify gaps and determine potential projects/investment areas.

The objective of this study was to compare SAIDI, SAIFI and electrical network design of Toronto to a peer group of major global cities. This started with a larger set of peer cities – the list was reduced to twelve peer cities based on several criteria for which city demographics, electrical network, climate, etc., characteristics were collected. Key to this effort was to select cities that had a mixed overhead and underground electrical network and had a similar cold climate (ice and snow) in a normal year. Out of the twelve identified, reliability data was available for eight of the peer cities – see Table 1, below. Two separate methods, ultimately combined into one, were used to short list five peer cities to analyze their electric grid designs with Toronto's. The five cities are: New York, London, Paris, Montreal and Vancouver. Montreal and Vancouver were included because of the detailed reliability data available that allowed us to conduct some additional analyses, outside the original scope of this effort, to compare the three major Canadian cities (see results in section 9.1 Appendix A).

City	City Type	SAIDI (Min)	SAIFI
Toronto	Mix – Cold	74.5	1.80
Hong Kong	UG – Warm	5.37	0.093
New York	Mix – Cold	16.6	0.139
Paris	Mix – Cold	17	0.3
London	Mix – Cold	34.44	0.32
Tokyo	UG – Warm	2	0.05
Miami	Mix – Warm	67.8	
Vancouver	Mix – Warm	102.6	0.54
Montreal	Mix – Cold	147.14	2.44

Table 1: SAIDI and SAIFI for the Selected Peer Group Cities

Except for Montreal and Vancouver, all other peer group cities SAIDI is better than Toronto. Except Montreal all other peer group cities SAIFI is better than Toronto.

For an N-1 designed electrical redundancy (contingency) network, Toronto reliability is very good. Against the peer group, made up mostly of N-2 and N-3 grids, Toronto lags. Toronto's N-1 network was built during a time when, historically compared to the peer group, it was a low density city. Also, it has a network that was designed for very different conditions than it faces today. Toronto's emergence as a financial center came much later than the peer group cities.

Toronto Hydro can not go backwards and re-implement the whole grid. It is just not practical. They can go forward and implement a new style of grid. To do this, an analysis of the costs of re-implementing the grid should be determined as a baseline cost to compare options against. This analysis should include the transmission costs to get a new third source into the city and then a high level estimate for the cost of implementing an N-2 network for the whole city based on starting from 3 independent sources. This should be used as a baseline only.

The next step for Toronto Hydro should be to break the city into reliability zones. These zones would contain like customers who need specific levels of reliability. Using these zones the cost of a new grid design should be calculated for each area. For the areas that need reliability that requires a grid that has a higher level of reliability then N-1, rather than new transmission, the design should look at both storage and distributed generation as the improvement in reliability. (Note: The Portlands Generation 550 Mw plant will provide additional capacity in the event that other generation sources at the transmission level are not available, however, within the distribution network, there will be limited impact on reliability. This is a low probability/high impact event. Also, equipment failures within the distribution network have a large impact on distribution network reliability.) Right now, large scale storage of electricity is not really cost effective but storage costs are moving in that direction. One form of storage that is cost effective is thermal storage (heat and cold), looking at providing some peak relief with thermal storage and some eventual reliability improvement from electricity storage should be considered as part of this step. This step should be completed based on the best commercial technology available off the shelf today and based on what the technology will probably be in 10 years.

As the province of Ontario and Toronto are on an aggressive path to embed distributed generation and energy storage, the network must become "smarter" to respond and adjust to these complexities.The Toronto Hydro Smart Grid program will have to address a lot more issues than in other cities to deliver the same results because there are only two independent sources of power to Toronto and the resulting grid design philosophy. Building in demand side management, embedded generation, more redundancy and network automation will be core parts of the smart grid program and critical to not only improving reliability, but maintaining current levels in the interim.

Based on the peer group cities analysis results and reviewing related efforts underway or planned at Toronto Hydro, a reliability transformation map was developed that takes a holistic approach to the issues Toronto Hydro is facing. The reliability improvement at Toronto Hydro will have to be a multi-year journey that will address multiple areas: people & process, renewable & embedded generation, physical grid upgrades and smart grid. This program will require executive commitment and communication throughout Toronto Hydro.

The map – see Figure 1 below – is grouped into three waves over the next ten years: Planning (2009 to 2010), Foundation (2011 to 2013), and Steady State (2014 to 2018).

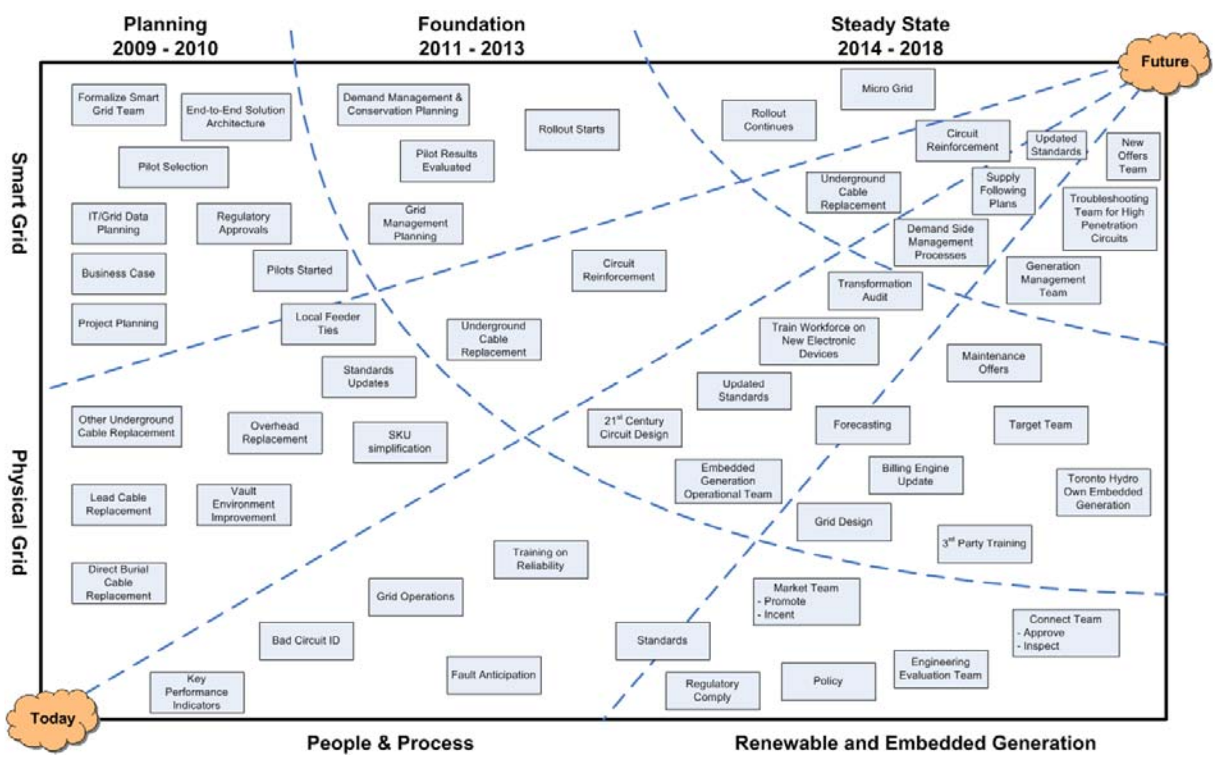

Figure 1: Toronto Hydro Reliability Transformation Map

Toronto Hydro has already began to make significant changes in the design philosophy for the electric grid these changes provide a strong directional change in grid design that in the long run will provide a much improved electrical network.

This report provides many additional recommendations and details. These are identified in Section 6.6 for the electric network design and Section 7.4 for the reliability transformation roadmap. Section 8 provides suggested future studies that should be undertaken.

2. Reliability Peer Group Cities Comparison Overview

The objectives of the reliability peer group cities study is to:

- Compare Toronto Hydro to their peer group of major global cities for mutually agreed upon reliability parameters using the standard IEEE Reliability indices. The primary index used is SAIDI. All others are considered secondary.
- Compare and contrast Toronto Hydro's grid design to the three (3) mutually agreed upon best-in-class cities from reliability standpoint based on their SAIDI scores.
- Determine a range of activities based on the peer cities reliability indices and electric network designs that Toronto Hydro could undertake to improve reliability.

SAIDI was selected as the primary index because out of the 25 IEEE Standard indices for reliability, it is the most reported and used by utilities. From a regulatory standpoint, more than 70 percent of the regulators in North America use SAIDI as a primary index.

Capgemini worked with Toronto Hydro to determine the peer group of global cities from which to get reliability data. Capgemini used public domain information first and then worked directly with the peer group to obtain more information. The goal was to get like data from 75% of the peer group. The study was limited to12 cities potentially being designated as peer cities.

Once the data was collected, an analysis was conducted to determine what process / factors were applied by the peer cities/utilities to the raw data. For example, regulators for each Utility may have different criteria (e.g., interruption duration, # of customers affected) for what's included in SAIDI for customer outages resulting from a storm. This allowed us to normalize the reliability data so that it's comparable from city to city and to understand the differences in the raw and processed data.

Capgemini then worked with Toronto Hydro to examine the zones in their grid and identify the different levels of electric source redundancy (contingency) that are in-place in each major zone. This information was used to determine whether the zone is N (single source), N-1(two sources) or higher contingency and how that compares with the utilities in the peer group cities. The result is documented in high level peer group city electrical circuit maps that are used to compare the cities financial and commercial districts. These maps were created for several peer group cities and for Toronto to analyse the physical electrical circuit design differences. The maps address the core financial district, a mixed business district and a residential district. The maps include basic power flow, how the N, N-1 or higher contingency is created, and the segmentation and self healing capability of the network. The differences were identified and a summary of the key points related to each difference and its impact on the overall reliability, documented. The maps are primarily intended to help understand the differences between the way the networks are designed and configured, and are not intended to be engineering documents.

Once the peer group cities maps were reviewed and accepted by Toronto Hydro, a workshop was held to understand the key differences between the best in class cities and Toronto Hydro to determine potential changes / improvements that could be applied by Toronto Hydro. These potential changes/improvements were used to develop the list of possible projects that can be applied by Toronto Hydro to improve reliability.

3. PEER GROUP CITIES SELECTION

From a list of the major cities around the world, a session was held to reduce the list to a reasonable size for peer group cities comparison. The criteria agreed to for this reduction were focused on:

(1) City size, population had to be more than 1 million people in the core city and more than 3 million people in the metropolitan area.

(2) City reputation, the city had to have a name that was recognizable to everyone in the room and be an attractive place to visit and/or live.

(3) Industry reputation, the cities had to have an active electric utility, they needed to be known to the various industry technical societies, whether it was CEATI, EPRI, IEC, IEA, or IEEE, etc. and the utilities had to participate in one or more of these societies in a noticeable way. (e.g. papers, presentations, major meeting attendance)

(4) No large population of transient people living in temporary housing in the margins of the city with makeshift (temporary) utilities.

These criteria provided what was felt to be a peer group for Toronto Hydro, a city that is internationally recognized, more than 1 million people living in the core city and the utility serve the city is active in the different standards committees. This peer group was discussed between the Toronto Hydro and Capgemini personnel participating in the reliability study to make sure everyone agreed that the cities fit the criteria. All of work at this level was done based on reputation and people's own knowledge, not on research. The path going from a list of potential cities to the peer group cities and the cities for which we conducted a circuit design analysis is shown in Figure 2, The circled numbers identify the number of peer cities being considered in that stage of the Peer Cities Selection Process.

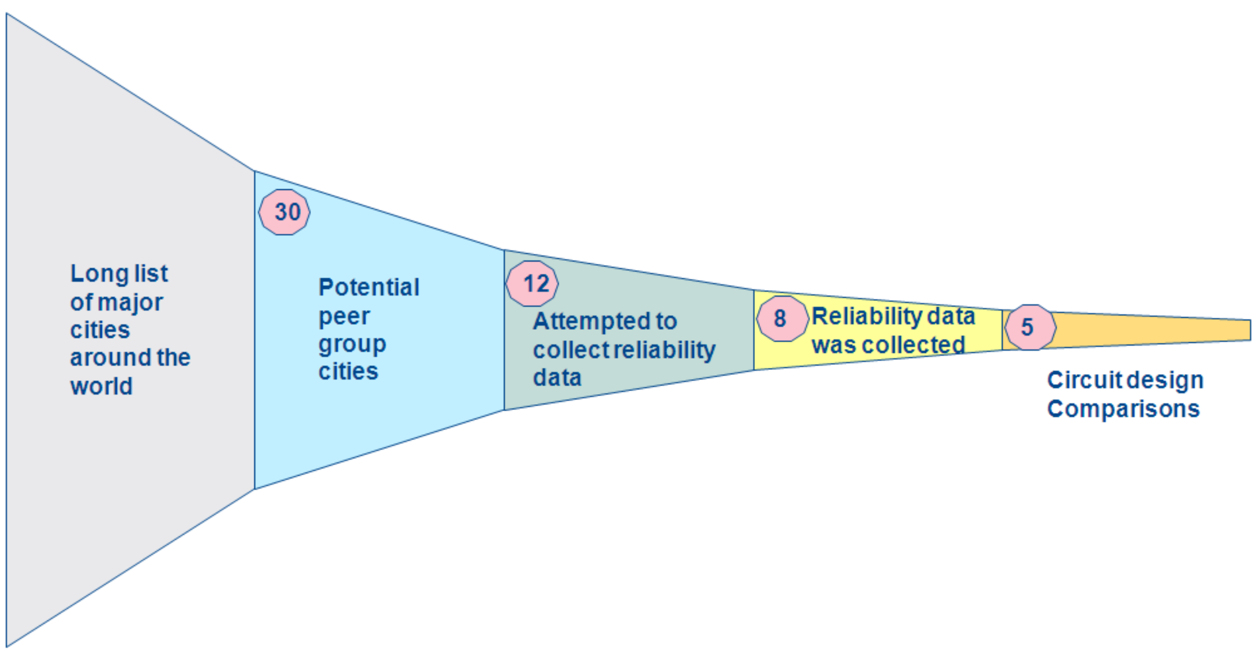

Figure 2: Peer Cities Selection Process

The criteria identified above were used to reduce the initial cities list to approximately 30 potential peer group cities. Once this list was assembled, demographics were collected about each of the cities. The characteristics collected included:

(1) City size – population density and growth rate.

(2) Industry Mix – Mix of industrial, included type when available, and residential usage.

(3) Geography & Topology – Vegetation in the city in a qualitative fashion. Was the city flat or hilly or were there other natural characteristics that made it unique.

(4) Mix of Electrical Networks – Overhead and Underground distribution mix.

(5) Climate/Weather – Storm patterns; Cold vs. Warm climate.

(6) Estimated Peak Load

(7) Projected Load Growth

(8) Utility Type – Investment Own Utility (IOU) vs. Municipal, Government, etc.

(9) The ability to collect the reliability information from the cities, how available was it?

An analysis was conducted to validate the initial impressions of the team and validate that the cities in the peer group did indeed belong in the peer group. This information is documented in Appendix B section 9.2.2. Of note, at this point in the project, there was no visibility by the reliability study team into the specific reliability data in any city.

3.1. Peer Group Cities Selections for SAIDI and SAIFI Analysis

The next step was to select no more than 12 cities from this list as potential peer group cities for which we would attempt to collect reliability data and related information. From the earlier collected data on the 30 potential peer group cities, five key criteria were identified, prioritized and used to select the 12 cities through a workshop with the team. The top five criteria are documented in Appendix B section 9.2.1 and summarized below:

(1) **Industry Mix**: First consideration is the mix of commercial, industrial and residential usage. A secondary consideration is the type of industry. For example, does the industrial segment include a large inductive load component? The industry mix can drive different network design and reliability requirements.

(2) **Mix of Electrical Networks**: The mix of electrical supply arrangements, operation voltages, overhead or underground infrastructure, loop feeders, SCADA switching, etc. can have large effect on the reliability.

(3) **Climate**: Climate has a direct effect on the reliability. In an overhead infrastructure, cold weather conditions will often cause more outages than warm weather. Similar warm and humid areas can also cause outages in an underground infrastructure.

(4) **Geography**: Specifically, vegetation contacts with overhead electrical infrastructures are common cause for outages. The situation worsens during extreme weather conditions such as wind and ice storms. The City of Toronto actively maintains the urban forest as a means of protecting and enhancing the City's natural heritage.

(5) **Population Density**: This can drive electricity demand and present more challenging situations in operating the electrical network.

These five criteria allowed the team to focus on the cities that were most relevant to the study, providing a peer group not based on subjective judgement, but supported through quantification. One of the keys was picking cities that had a mixed overhead and underground network. To this end a small table was created that used two criteria to rank the cities. The first criteria was whether the city saw ice and snow in a normal year. Cities that did not, were labelled “Warm”. The other criteria was whether cities provided power to at least 10 percent of their customers or 10 percent of the load from an overhead system. Cities that met these criteria were labelled “Mixed”. No city in the peer group was a pure overhead system.

With these two criteria, as well as the remaining three, the initial list of 30 potential peer group cities was narrowed to the following twelve (12) cities that were agreed to by all the participants:

Asia:

1. **Hong, Kong, China**: Large metropolitan area with large residential centers in the city. Although climate is not similar the area does get some heavy storms.
   - 60% residential in the city
   - Primarily underground infrastructure – lot of overhead on the edges of the cities and in the hills
   - Tropical monsoon. Cool and humid in winter, hot and rainy from spring through summer, warm and sunny in fall. Some times can get typhoons, flooding, and minor earthquakes
   - Very little vegetation in the core city, lots on the edges - it goes from high-rise buildings to farms in less than 500 meters
   - Population: 7,000,000 People (City), Area: 1,104 km^2 = Density of 6,340 People/km^2
2. **Tokyo, Japan**: Very populated area with different climate than Toronto. Downtown has a mix of residential and C&I districts with a diverse set of buildings. Outside of downtown Tokyo has similar overhead and underground infrastructure mix to Toronto.
   - 50% residential in the city
   - 100% underground infrastructure in the city, when you get outside of the core downtown you see more overhead infrastructure
   - Climate is warmer than Toronto, but there is a winter season that brings some minor storms
   - Very little vegetation in the core city, some parks and trees
   - Population: 8,700,000 People (City), Area: 6,993 km^2 = Density of 4,750 People/km^2
3. **Singapore**: City has similar mix of residential and commercial customers, and similar mix of businesses.
   - 30% residential in the city
   - Electric infrastructure is mostly underground in the core downtown.

- Climate is tropical
- Heavy vegetation in some areas – mostly residential trees
- Population: 4,300,000 People (City), Area 704 km^2 = Density of 6,520 People/km^2

North America:

4. **Chicago, IL**: Large metropolitan area, with similar climate and stormy weather. Downtown is mostly commercial.
   - 30% residential in the city
   - Mix of underground and overhead electric infrastructure (as density goes down - overhead increases).
   - Named the "windy city" for the strong wind and storms during the winter. Winter is cold and can frequently get ice storms.
   - Most residential neighborhoods have heavy vegetation
   - Population 2,842,518 People (City), Area: 588 km^2 = Density of 4834 People/km^2
5. **New York, NY**: Large metropolitan area, similar concentration of financial industry in downtown area. Similar climate since it is also on the coast, although conditions are less severe in Toronto since the water is fresh water as oppose to saltwater in New York.
   - 60% residential in the city
   - Manhattan is all underground the rest of the city is about a 60/40 mix of overhead and underground
   - Coastal city gets a lot of storms – some hurricanes, and flooding. Sometimes it has ice storms
   - Most residential neighborhoods have heavy vegetation
   - Population 8,143,197 People (City), Area: 785 km^2 = Density of 10,373 People/km^2
6. **Dallas, TX**: Financial hub of TX, downtown is mostly business, rapid residential growth in downtown.
   - 25% residential in the city
   - Electrical infrastructure is 40% underground
   - Warm winters with some ice storms, hot summers (humidity is similar to Toronto in the Summer) - some storms
   - Lightly wooded in most of the downtown areas
   - Population 1,213,825 People (City), Area: 888 km^2 = Density of 1,367 People/km^2
7. **Miami, FL**: Frequent storms, floods, and similar industry mix.
   - 50% residential in the city
   - Mixed overhead and underground electrical infrastructure

- Many storms during the hurricane season
- Residential trees
- Population: 386,417 People (City), Area: 94 km^2 = Density of 4,110 People/km^2

Canada:

8. **Vancouver, Canada**: Canadian city that is recognized globally.
   - 35% residential in the city
   - Mixed overhead and underground electrical infrastructure
   - Warmer than Toronto, but there is a winter season
   - City is light on vegetation, gets heavier as you move outside of the downtown
   - Population: 612,000 People (City) , Area: 1,120 km^2 = 1650 People/km^2
9. **Montreal, Canada**: Canadian city that are recognized globally. Much heavier snow and storm patterns.
   - 50% residential in the city
   - Mixed overhead and underground electrical infrastructure
   - Cold winter, strong snow storms
   - City is light on vegetation, gets heavier as you move outside of the downtown
   - Population: 1,621,000 People (City), Area: 1,740 km^2 = Density of 1,850 People/km^2

Europe:

10. **Paris, France**: Large metropolitan area, similar concentration of C&I in the downtown area.
    - 35% residential in the city
    - Financial and business district is all underground, the rest of the city is about a 60/40 mix of overhead and underground
    - The city is not in any storm pattern paths, but still get some heavy storms, and snow storms in the winter
    - Most residential neighborhoods have heavy vegetation
    - Population: 2,181,000 People (City), Area: 2,723 km^2 = Density of 3,550 People/km^2
11. **London, England**: Large metropolitan area, similar concentration of C&I in the downtown area. Climate is also very similar.
    - 40% residential in the city
    - Electrical infrastructure is 90% underground
    - Rainy and cloudy, city is in-land but still get some weather form the coast. In the winter city can get heavy snow storms

- Most residential neighborhoods have heavy vegetation
- Population: 7,620,000 People (City), Area: 1,623 km^2 = Density of 5,100 People/km^2

12. **Amsterdam, Nederland**: Major European metro area with similar industry mix.

- 40% residential in the city
- Mixed overhead and underground electrical infrastructure
- Strongly influenced by the North Sea. Mild winter temperature seldom goes below 0°C.
- Heavy vegetation in the city and outside
- Population: 758,000 People (City), Area: 219 km^2 = Density of 4,459 People/km^2

Toronto, Canada: The subject of this study.

- Base on the 2007 Annual Report Toronto Hydro has 601,515 Residential customers out of 679,913 (88% Residential)
- Mixed overhead and underground electrical infrastructure
- Cold weather conditions in the winter. Often suffer extreme condition such as wind storms, ice storms and lightning
- The City of Toronto maintains the urban forest as a means of protecting and enhancing the City's natural heritage. Contact with overhead electrical infrastructure is common.
- Population: 2.5 Million in Toronto (City), greater Toronto is about 7 Million
- Density: 2,650 People/km^2

This information is also included in Appendix B section 9.2.2.

At this point the team worked to collect reliability information for the peer group cities. There was an agreement when this list was compiled, that getting reliability data on 8 of the 12 cities would be considered a success.

As mentioned earlier, up to this point, no one on the team had access to the reliability information for the cities in the study. The next step in the process was to collect the reliability information and from that, further narrow the list to a set of cities that would be used for detailed analysis of what the differences were between the cities for reliability. Data was collected from the target peer group cities over a period of several weeks via direct contact with each of the cities/utilities. In some cases summary data was provided and, in others, we received detailed information. For the next step in the process, the summary data was used.

The data collection focused on SAIDI – the most used of the IEEE reliability indices. We were able to obtain reliability data for eight (8) of the twelve (12) cities. They are:

1) New York
2) Paris
3) London
4) Montreal

5) Vancouver
6) Tokyo
7) Hong Kong
8) Miami

3.2. Peer Group Cities Selection for Detailed Electrical Network Design Analysis

Once the reliability data was collected and reviewed, two methods were identified to select the three (3) peer group cities (from the 8 potential) for which detailed electrical network design analysis was conducted. The selection methods and resulting recommendations for the three peer group cities are provided below.

Method 1: Select the cities with the lowest SAIDI and the best comparison of city type to Toronto (Mix – Cold).

The cities recommended are New York, Paris and London.

Summary comments resulting from the use of this method and the three (3) cities recommended include:

- Cities have lower SAIDI than Toronto
- Cities, overall, are very similar to Toronto
- Will allow for comparison across two continents, North America and Europe
- Cities contain financial centers/districts, similar to Toronto

Method 2: Select one city from each continent to allow for continent-specific Utility Industry, Legislative, and Regulatory practices to be evaluated. Note: this results in four (4) cities being selected.

The cities recommended are Tokyo, New York, Paris and, Montreal <u>or</u> Vancouver.

Summary comments resulting from the use of this method and the four (4) cities recommended include:

- An additional city requires detailed network design analysis.
- Montreal and Vancouver have worse SAIDI and SAIFI than Toronto, however, it may be interesting to evaluate what major reliability improvements have been made and resulted in limited success.
- Will provide for broader continent-specific Utility Industry, Legislative and Regulatory practices to be considered.
- Tokyo is very different from Toronto, plus the Japanese government made a significant capital investment in reliability improvements in the mid-1980's, which may limit the comparison value.

Based on subsequent team discussions, a blended methodology was ultimately used, taking the three suggested cities from method one and adding Montreal and Vancouver for a total of five cities.

This selection was made because the cities better fit the profile of Toronto with similar reasons for outage and very different network designs. This allowed for a wider range of network designs in looking for what made the largest difference in reliability. It also allowed the team to look at very active cities (Montreal and Vancouver) where several reliability improvement projects have been carried out and yet the reliability is still not to the level of Toronto.

4. Toronto Hydro Reliability Data

4.1. Facts and Characteristics

According to the 2007 Annual Report Toronto Hydro service territory covers downtown Toronto and suburbs for a total of 679,913 customers the total population is 2,503,281. Customer mix is:

Type	Count
Residential	601,515
General Service <50kW	66,245
General Service 50kW to 1000kW	11,591
General Service 1mW to 5mW	513
Larger Users > 5mW	49

Table 2: Toronto Hydro Customer Mix (2007 Annual Report)

Following, are some other facts:

Fact	Value
System Area (km^2)	650
Estimated Peak Load System (MW)	5,050
Installed In-City Generation (including dedicated transmission lines from generators outside urban area)	Fuel Cell/CoGen Facility in Toronto operated by Enbridge feeding into the Grid – see note.
Transmission Design LOLE	800,087,663 kWh (in 2007) - 3% of electricity delivered. Generally losses are between 3% - 3.2%
Use of Secondary Networks (km) - Low Voltage Meshed Grids	2881.645
Use of GITs	62,909 transformers owned by Toronto Hydro. 60,871 in service which 1950 are Network transformers.
Building underground / over-built substations	TS (Transformer Stations): 35 MS (Municipal Stations): 173

	CS (Customer Stations): 13
Design Criteria (urban)	N, in some areas N-1 contingency

Table 3: Toronto Hydro Electric Network Characteristics

***** NOTE: Cell CoGen owned and operated by Enbridge Gas *****

The Unit consists of a 1.2 MW Fuel Cell and a 1 MW Turbo Expander (Heat Extraction Generation) giving the unit a 2.2 MW full electrical generation capacity. The Fuel Cell is cycled at 0.6 MW and the Turbo Expander is cycled from 0-0.8 MW. The Unit is load following. They operate it by following the loading/demand on the Grid. The unit is 100% hooked into the Grid and does not electrically supply the building it sits close to. It is operated at ~73% Capacity and it has better than 90% Availability. The life expectancy is better than 20 yrs.

4.2. Reliability Metrics and Targets

The system wide reliability values for SAIFI and SAIDI are based on 2008 data:

SAIFI	1.80
SAIFI Targets	2.0

Table 4: Toronto Hydro SAIFI

SAIDI	74.5
SAIDI Targets	80

Table 5: Toronto Hydro SAIDI

SAIDI and SAIFI Criteria:

1. Excludes Major Event Days (there were no MED in 2008). MED is calculated using the 2.5 beta method; it was 6.09 minutes for 2008.
2. Excludes momentary outages. Momentary outages are those outages which last less than a minute.
3. Toronto Hydro does not have any reliability thresholds penalties for major outages.

4.3. SAIDI Adjustments to Allow for Like-to-Like Comparison

Raw reliability data that listed all the outages for 2008 was provided for both the Toronto metro area and the downtown area. This has been included in Appendix B section 9.2.3. From the Toronto Hydro (Toronto metro area) reliability data, a total of 3,094 outages (customer interruptions) were recorded in 2008.

In order to compare Toronto metro area reliability to the other peer cities selected, a decision was made to compare like-to-like. To do this, it was important to remove incidents from the overall raw reliability data for Toronto that would not have happened in the other cities. For instance, in the tropical cities, ice and snow would not have interrupted the service. In cities where the whole infrastructure is underground, adverse weather would have a limited effect. To do this the, outage records were sorted by cause and each of the causes were added up. The primary cause codes used by Toronto Hydro are listed below. The results of this sorting by cause code are provided in Appendix B section 9.2.4.

A customer interruption has been defined in terms of primary and secondary causes of the interruption. The primary causes of interruption have been assigned the following codes (The codes and definition are base on the Distribution Service Continuity Committee of CEA):

1. **Unknown/Other:** Customer interruptions with no apparent cause or reason which could have contributed to the outage.
2. **Scheduled Outage:** Customer interruption due to the disconnection at a selected time for purpose of construction or preventive maintenance.
3. **Loss of Supply:** Customer interruption due to problems in the Bulk Electricity System (BES) such as: Under frequency load shedding, transmission system transients, or system frequency excursions. All interruptions up stream of the Delivery Point from the BES (Transmission system) are to be classified as “Loss of Supply” outages.
4. **Tree Contacts:** Customer interruptions caused by faults due to trees or tree limbs contacting energized circuits.
5. **Lightning:** Customer interruptions due to lightning striking the distribution system resulting in an insulation breakdown and/or flashovers.
6. **Defective Equipment:** Customer interruptions resulting from equipment failures such as deterioration due to age, inadequate maintenance, or imminent failures detected by maintenance.
7. **Adverse Weather:** Customer interruptions resulting from rain, ice storms, snow, winds, extreme ambient temperatures, freezing fog, or frost and other extreme conditions.
8. **Adverse Environment:** Customer interruptions due to equipment being subjected to abnormal environment such as salt spray, industrial contamination, humidity, corrosion, vibration, fire or flooding.
9. **Human Element:** Customer interruptions due to the interface of utility staff with the system such as incorrect records, incorrect use of equipment, incorrect construction or maintenance, switching errors, commissioning errors, deliberate damage, or sabotage.
10. **Foreign Interference:** Customer interruptions beyond the control of the utility such as birds, animals, vehicles, dig-ins and foreign objects.

During the analysis of the interruption cause codes it was clear that the interruption causes fall into two main categories: (1) type of electrical network (underground vs. mix – underground and overhead) and, (2) type of climate. We created four different combination sets (referred to as city type combinations) based on these predominate categories:

1. **<u>Mix-Warm</u>**: Mix overhead and underground electrical infrastructure in a warm climate.
2. **<u>Mix-Cold</u>**: Mix overhead and underground electrical infrastructure in a cold climate.
3. **<u>UG-Warm</u>**: Underground electrical infrastructure in a warm climate.

4. **UG-Cold**: Underground electrical infrastructure in a cold climate.

To calculate SAIDI and SAIFI from Toronto Hydro reliability data for each of those city types, we pulled a subset of the interruption cause codes that would be affected by the electrical network type or type of climate. This created a base customer minutes of outage number and Customer Interruption. Once we assigned the pulled interruption cause codes to each of the four city types we were able to calculate SAIDI and SAIFI for each city type to provide a baseline for comparison. The results are provided in Table 6 – SAIDI and Table 7 – SAIFI, below.

The first column in those tables list all the primary customer interruption causes that we pulled out from Toronto Hydro's reliability data. That allowed us to calculate the customer minutes of outage and customer interruptions that we pulled out, leaving the baseline. Once we cross-referenced the customer interruption causes to the four city type combinations we were able to calculate SAIDI and SAFI for each of the city type combinations. The complete analysis spreadsheet is attached as part of Appendix B section 9.2.4.

With these analysis results, we now have SAIDI and SAIFI numbers for each of the city type combinations based on Toronto Hydro reliability data that we considered to be comparable on a like-to-like basis (based on the specific city type combination assigned earlier to the peer group city) to the SAIDI and SAIFI numbers for the potential comparison cities.

Customer Interruption Cause	Customer Min Out	SAIDI	Mixed - Warm	Mixed - Cold	UG-Warm	UG-Cold	Mixed - Warm SAIDI	Mixed - Cold SAIDI	UG-Warm SAIDI	UG-Cold SAIDI
Total	50,873,114	74.53								
Total pulled	15,066,746	22.07								
Base	35,806,368	52.46	x	x	x	x	52.46	52.46	52.46	52.46
ADVERSE WEATHER / TREE CONTACTS	4,299,015	6.30	x	x			6.30	6.30		
ADVERSE ENVIRONMENT	2,355,064	3.45	x	x	x	x	3.45	3.45	3.45	3.45
BIRD / ANIMALS / FOREIGN INTERFERENCE	643,480	0.94	x	x			0.94	0.94		
FOG	0	0.00								
FREEZING RAIN EXTREME / ADVERSE WEATHER	170,173	0.25		x		x		0.25		0.25
NORMAL WEATHER / TREE CONTACTS	731,057	1.07	x	x			1.07	1.07		
OTHER / ANIMALS / FOREIGN INTERFERENCE	147,084	0.22	x	x			0.22	0.22		
RACCOON / ANIMALS / FOREIGN INTERFERENCE	146,176	0.21	x	x	x	x	0.21	0.21	0.21	0.21
RAIN EXTREME / ADVERSE WEATHER	1,723,898	2.53	x	x			2.53	2.53		
SNOW EXTREME / ADVERSE WEATHER	482,848	0.71		x		x		0.71		0.71
SQUIRREL / ANIMALS / FOREIGN INTERFERENCE	709,325	1.04	x	x			1.04	1.04		
SUSPECTED BRUSH CONTACTS / TREE CONTACTS	98,346	0.14	x	x			0.14	0.14		
VARIOUS - GUYS, ANCHORS,BRACKETS,ETC / OVERHEAD SUPPORT STRUCTURE / DEFECTIVE EQUIPMENT	768	0.00	x	x			0.00	0.00		
VEHICLE / FOREIGN INTERFERENCE	1,469,583	2.15	x	x			2.15	2.15		
WIND EXTREME / ADVERSE WEATHER	2,089,929	3.06	x	x			3.06	3.06		
Total							73.58	74.53	56.12	57.08

Table 6: Toronto Hydro Customer Interruptions Cause Analysis (SAIDI)

Customer Interruption Cause	Customer Interruption	SAIFI	Mixed - Warm	Mixed - Cold	UG-Warm	UG-Cold	Mixed - Warm SAIFI	Mixed - Cold SAIFI	UG-Warm SAIFI	UG-Cold SAIFI
Total	1,203,272	1.763								
Total pulled	277,356	0.406								
Base	925,916	1.357	x	x	x	x	1.357	1.357	1.357	1.357
ADVERSE WEATHER / TREE CONTACTS	61,536	0.090	x	x			0.090	0.090		
ADVERSE ENVIRONMENT	16,483	0.024	x	x	x	x	0.024	0.024	0.024	0.024
BIRD / ANIMALS / FOREIGN INTERFERENCE	18,085	0.026	x	x			0.026	0.026		
FOG	0	0.000								
FREEZING RAIN EXTREME / ADVERSE WEATHER	2,695	0.004		x		x		0.004		0.004
NORMAL WEATHER / TREE CONTACTS	24,518	0.036	x	x			0.036	0.036		
OTHER / ANIMALS / FOREIGN INTERFERENCE	1,364	0.002	x	x			0.002	0.002		
RACCOON / ANIMALS / FOREIGN INTERFERENCE	7,681	0.011	x	x	x	x	0.011	0.011	0.011	0.011
RAIN EXTREME / ADVERSE WEATHER	23,296	0.034	x	x			0.034	0.034		
SNOW EXTREME / ADVERSE WEATHER	7,214	0.011		x		x		0.011		0.011
SQUIRREL / ANIMALS / FOREIGN INTERFERENCE	14,430	0.021	x	x			0.021	0.021		
SUSPECTED BRUSH CONTACTS / TREE CONTACTS	8,774	0.013	x	x			0.013	0.013		
VARIOUS - GUYS, ANCHORS,BRACKETS,ETC / OVERHEAD SUPPORT STRUCTURE / DEFECTIVE EQUIPMENT	24	0.000	x	x			0.000	0.000		
VEHICLE / FOREIGN INTERFERENCE	37,489	0.055	x	x			0.055	0.055		
WIND EXTREME / ADVERSE WEATHER	53,767	0.079	x	x			0.079	0.079		
Total							1.748	1.763	1.392	1.406

Table 7: Toronto Hydro Customer Interruptions Cause Analysis (SAIFI)

5. POTENTIAL PEER GROUP CITIES RELIABILITY DATA

Capgemini initially leveraged the International Urban Utilities Survey that is commissioned by IEEE, with the latest data available from Nov 2006. We also reached out to our global network of contacts in different utilities to obtain more recent data. The data we received from each of the sources was in varied levels of detail. Appendix B section 9.2.5 has the complete spreadsheets we received from all sources. Summarized, this data included:

- IEEE International Urban Utilities Survey: Summary data on the city facts and characteristics, and reliability data.
- Montreal and Vancouver: Detail data categorized by primary causes of interruption for metro and downtown areas.
- Rest of the cities: SAIDI and SAIFI numbers

Based on the information collected on the peer group cities, a city type combination (e.g., Mix – Cold) assignment was made for each city to allow for comparison of a city's SAIDI and SAIFI numbers to the similar Toronto city type combination that was calculated in Section 4. The results are provided in Table 8 – SAIDI and Table 9 – SAIFI, below.

City	City Type	SAIDI (Min)	Toronto SAIDI (Min)
Hong Kong, China	UG – Warm	5.37	56.12
New York, NY	Mix – Cold	16.6	74.53
Paris, France	Mix – Cold	17	74.53
London, England	Mix – Cold	34.44	74.53
Tokyo, Japan	UG – Warm	2	56.12
Miami, FL	Mix – Warm	67.8	73.58
Vancouver, Canada	Mix – Warm	102.6	73.58
Montreal, Canada	Mix – Cold	147.14	74.53

Table 8: Peer Group Cities – City Type Combination Assignments and SAIDI

****** NOTE: For Miami, FL we only able to obtain SAIDI values ******

City	City Type	SAIFI	Toronto SAIFI
Hong Kong, China	UG – Warm	0.093	1.392
New York, NY	Mix – Cold	0.139	1.763
Paris, France	Mix – Cold	0.3	1.763
London, England	Mix – Cold	0.32	1.763
Tokyo, Japan	UG – Warm	0.05	1.392
Miami, FL	Mix – Warm	***	1.748
Vancouver, Canada	Mix – Warm	0.54	1.748
Montreal, Canada	Mix – Cold	2.44	1.763

Table 9: Peer Group Cities – City Type Combination Assignments and SAIFI

6. RELIABILITY DATA ANALYSES

We received reliability data for 8 of the 12 potential peer group cities we initially short-listed. The data detail varied by city. Most sent us facts on the city/utility, high level characteristics of the electric network and reliability IEEE indexes. Vancouver and Montreal sent us detailed reliability records with the interruption causes.

Based on the level of reliability data received, several different analyses have been conducted. These analyses were used to support the selection of the three (3) peer group cities for which detailed electrical network design analysis was conducted. These analyses include:

- Potential Peer Group Cities SAIDI Comparison with Toronto.
- Potential Peer Group Cities SAIFI Comparison with Toronto.
- Electrical network design analysis for New York, Paris, London and Montreal.

The results of each of these analyses are provided in the subsections below. A detailed analysis of Montreal is provided in section 9.1 Appendix A.

6.1. Potential Peer Group Cities SAIDI Comparison with Toronto

Figure 3, below, is a plot of the SAIDI of the potential peer group cities against the adjusted (see results from Section 4) Toronto Hydro SAIDI based on the city type.

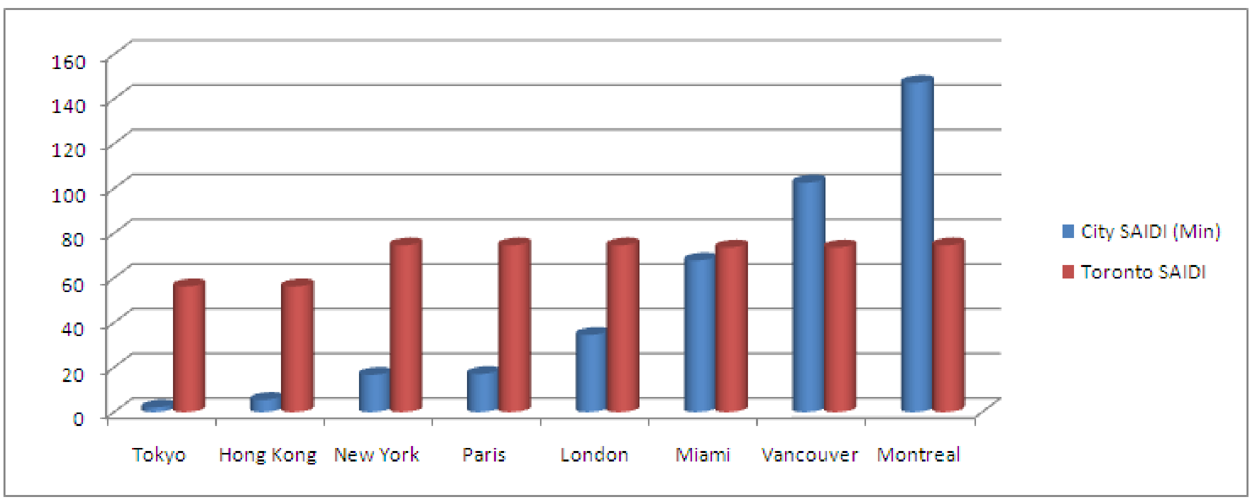

Figure 3: Peer Group Cities SAIDI Analysis

Observations:

1. Toronto SAIDI is better than the other two Canadian cities.
2. The rest of the peer group cities SAIDI are better than Toronto.
3. Miami SAIDI is very similar to Toronto although Miami is Mix – Warm city type.
4. The Mix-Cold cities SAIDI except Montreal are better than Toronto.

6.2. Potential Peer Group Cities SAIFI Comparison with Toronto

Figure 4 below, is a plot of the SAIFI of the potential peer group cities against the adjusted (see Section 4 results) Toronto Hydro SAIFI based on the city type.

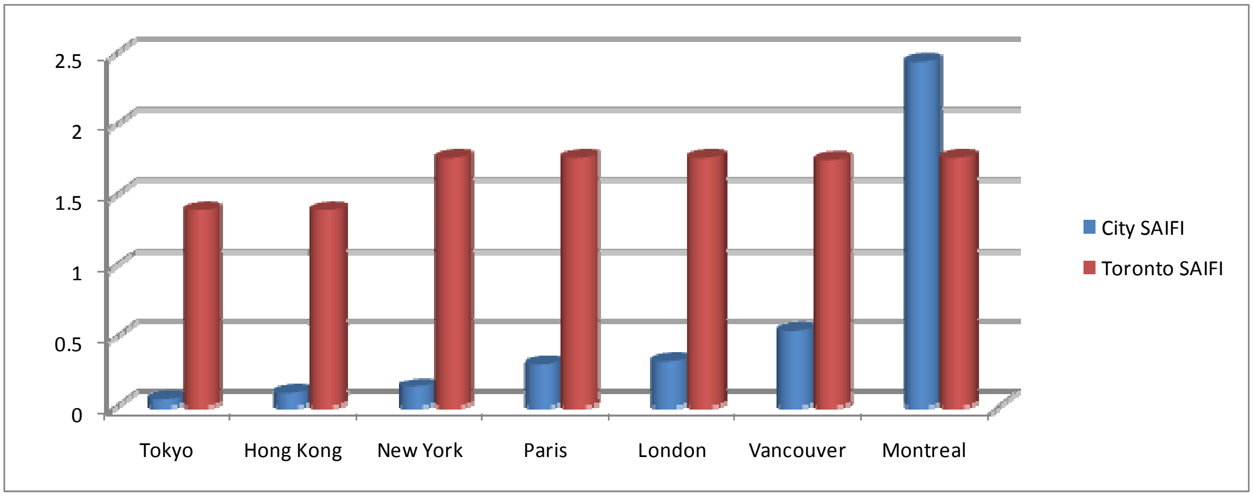

Figure 4: Peer Group Cities SAIFI Analysis

Observations:

1. Toronto Hydro SAIFI is better than Montreal.
2. Toronto Hydro has considerably more frequent outages per customer than Vancouver, but Vancouver outages are of longer duration than Toronto since Toronto SAIDI is better than Vancouver.
3. The rest of the peer group cities SAIFI are better than Toronto.
4. The Mix-Cold cities SAIFI except Montreal are better than Toronto.

6.3. Electrical Network Design Analysis

To understand the differences between the electrical networks designs in the peer group cities, and how the design drives N, N-1 or higher redundancy we selected five cities – New-York, Paris, London Montreal and Vancouver for detailed comparison. Electrical network designs (same as circuit schematics) were developed that include basic power flow, how the N, N-1 or higher reliability is created and the segmentation and self healing capability of the grid. The circuit schematics where developed to help understand the differences between the way things are done and are not intended to be engineering documents.

Figure 5,below, is the circuit schematic for Manhattan, New-York – each feeder ring covers about 20 Sq Blocks (roughly 4 blocks by 5 blocks). Four transmission sources and distribution substations supply each of the feeders that make it N-3 redundancy. The secondary network in each of the rings is N-1 redundancy – each one of the buildings is being supplied via two different lines from different side of the ring. Critical buildings are N-2 redundancy and most of them also have backup generation like diesels or gas turbines. Some like the Empire State

Building have major generation plants built into the basement and are capable of feeding power to surrounding buildings.

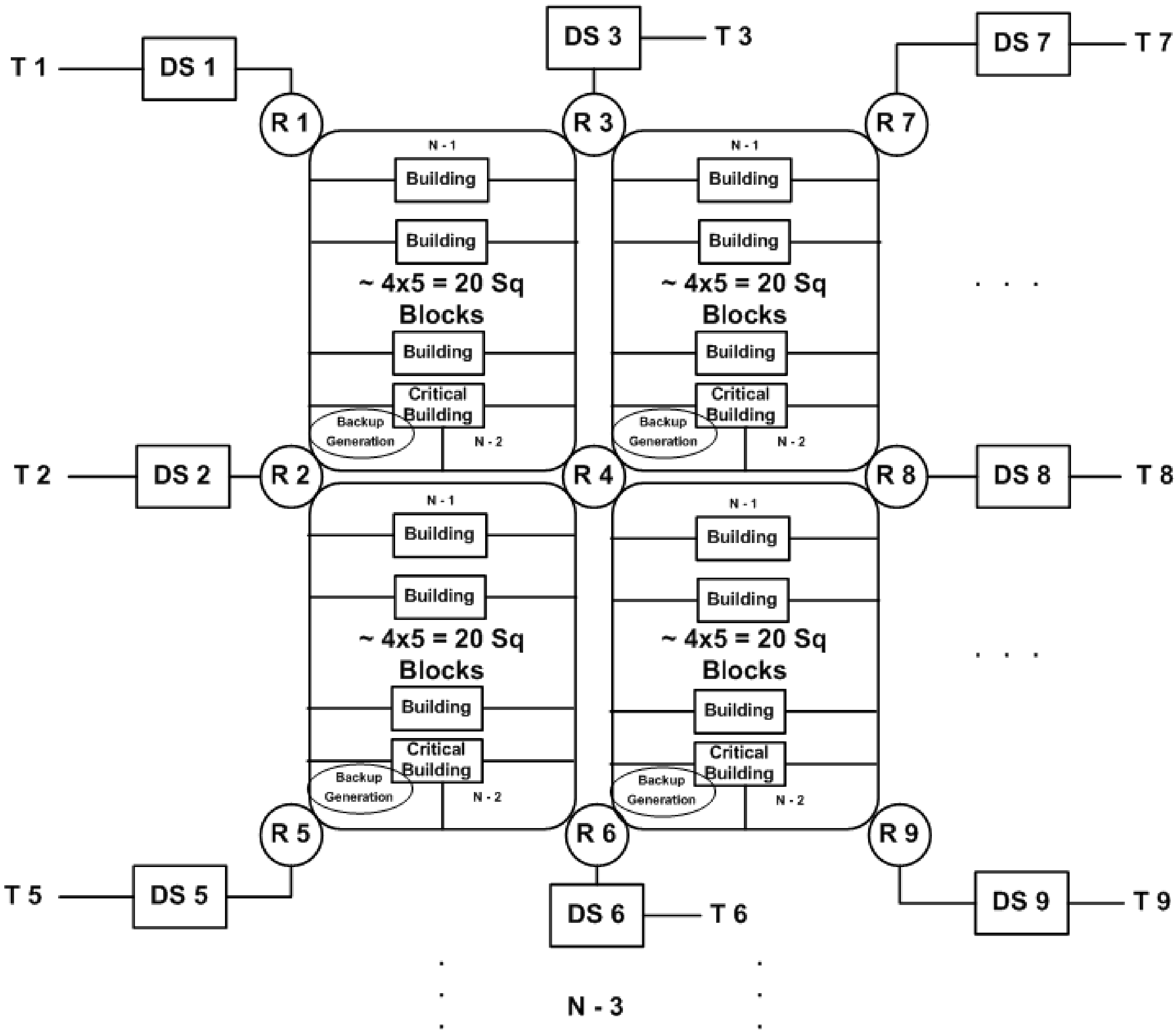

Figure 5: New-York Circuit Design

In Europe, there is a requirement (regulation) that cities be N-2 for almost all customers. Only the final step of providing power can be less then N-2. In almost every case, that final wire feeds between 1 and 40 customers and is the connection beyond the final voltage step down, but prior to the meter. Since most building wiring is also only N, this does not seem to have a major impact on the reliability of individual customers.

Figure 6, below, is the circuit schematic for Paris and London – both have very similar circuit design and if we look at most of the European cities we will find similar designs. Transformers in those cities supply electricity to about 200 customers (in Europe the average transformer supplies 40 customers, in cities the average is closer to 200, compared to the average in North America of 4-5 customers) and can be supplied from four different transmission lines and two distribution substations. At the Transmission level (66 kV) the circuit has N-3 redundancy level.

Between the distribution substation and the transformer the redundancy level is N-1, each transformer has two feeders and each comes from different distribution substation. At the transformer level the redundancy is N, but each transformer supplies just 200 customers, so the impact is minimal. From the transformer there are about 10 lines with each feeding about 20 customers. Some customers at this level will have backup generation specifically for the critical buildings. London has a lot more backup generation than Paris.

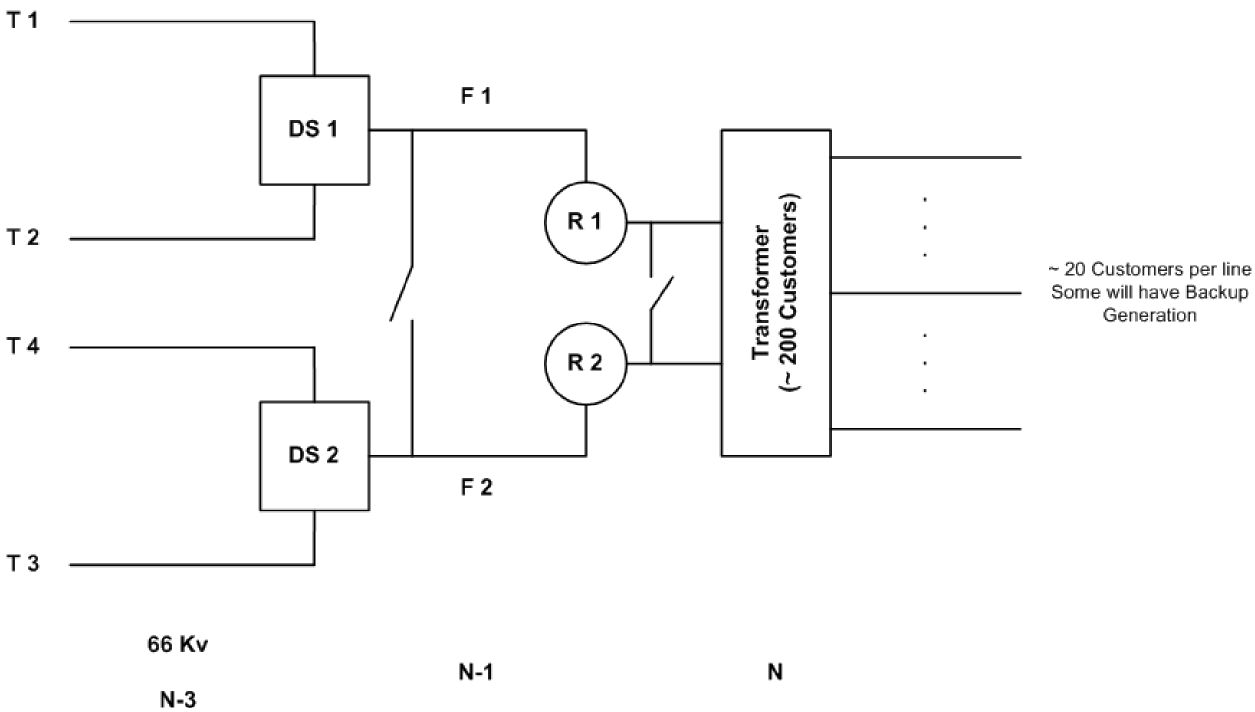

Figure 6: Paris/London Circuit Design

Vancouver uses a combination of different dual radial circuit configurations. There are a few places where an auto transfer switch is being used, but very infrequently. The following four Figures (7 to 10) are the different circuit configurations used at Vancouver.

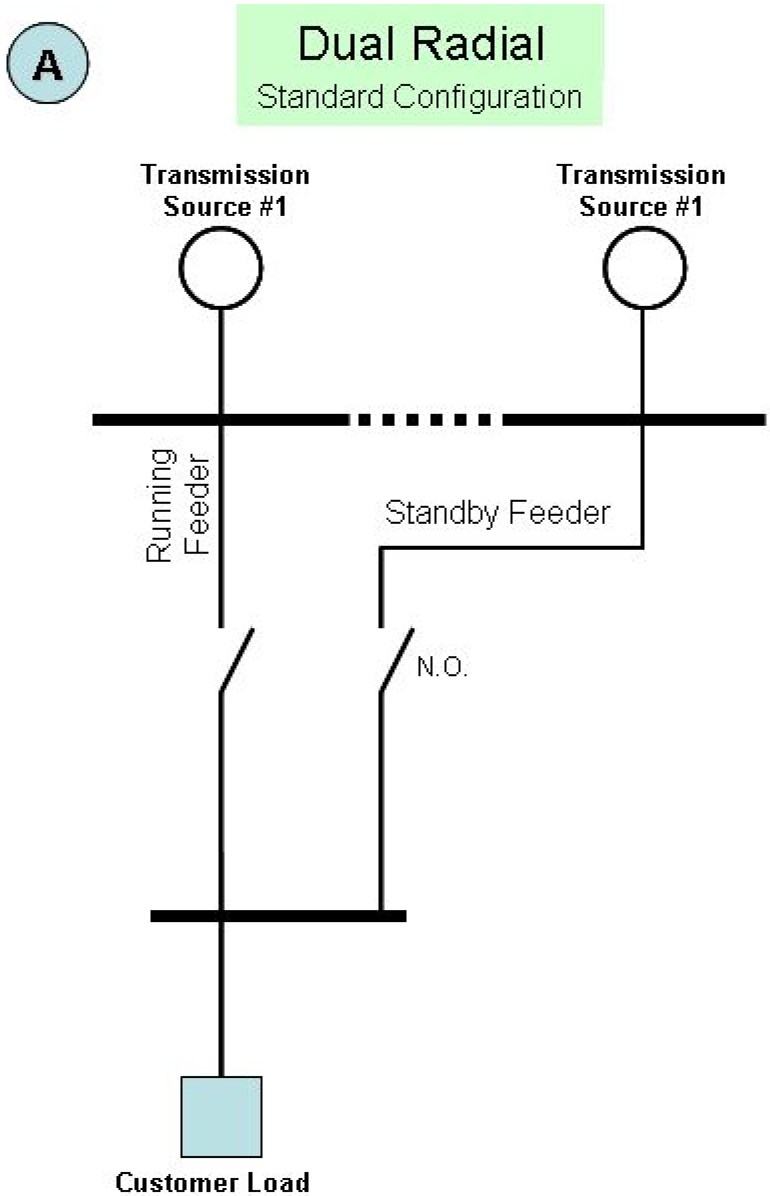

Figure 7: Vancouver Circuit Design – Dual Radial Standard Configuration

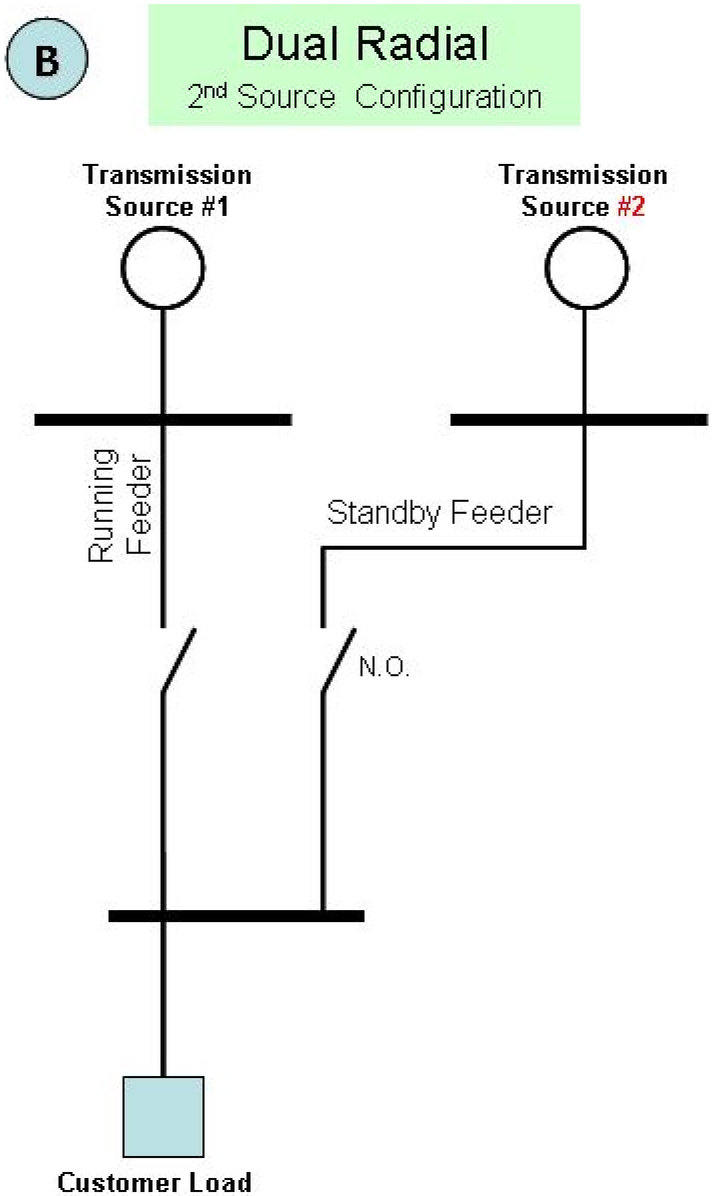

Figure 8: Vancouver Circuit Design – Dual Radial 2nd Source Configuration

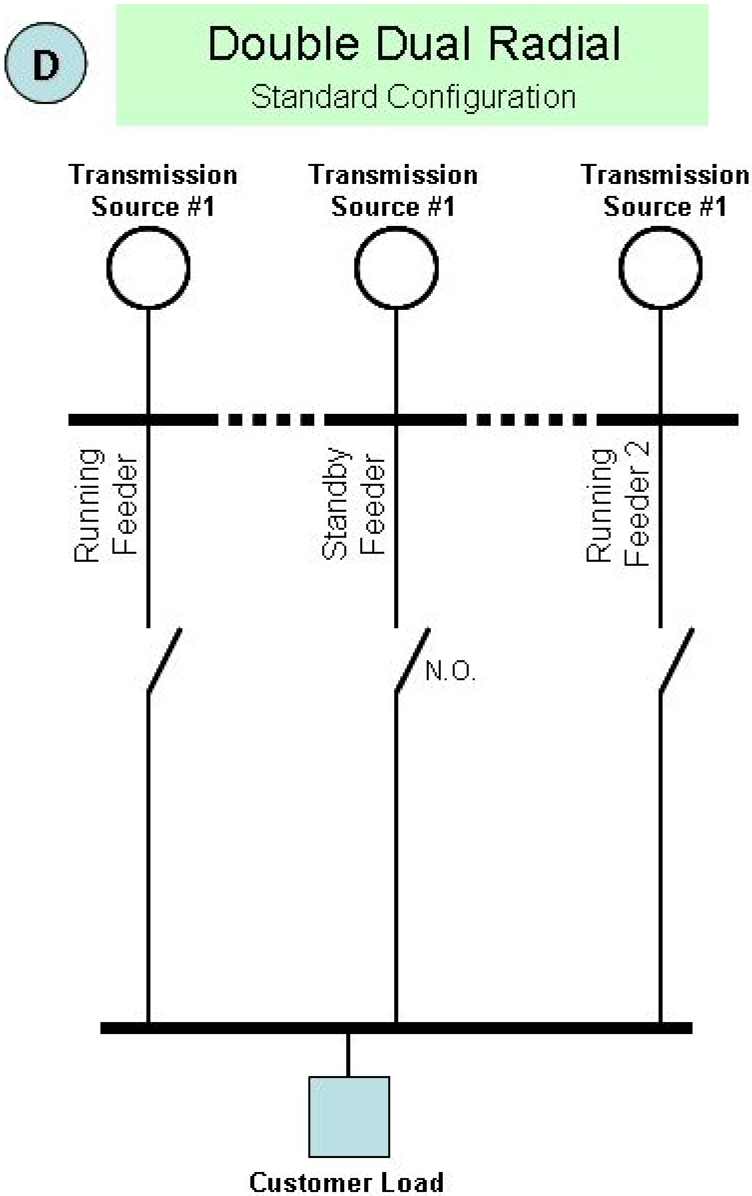

Figure 9: Vancouver Circuit Design – Double Dual Radial Standard Configuration

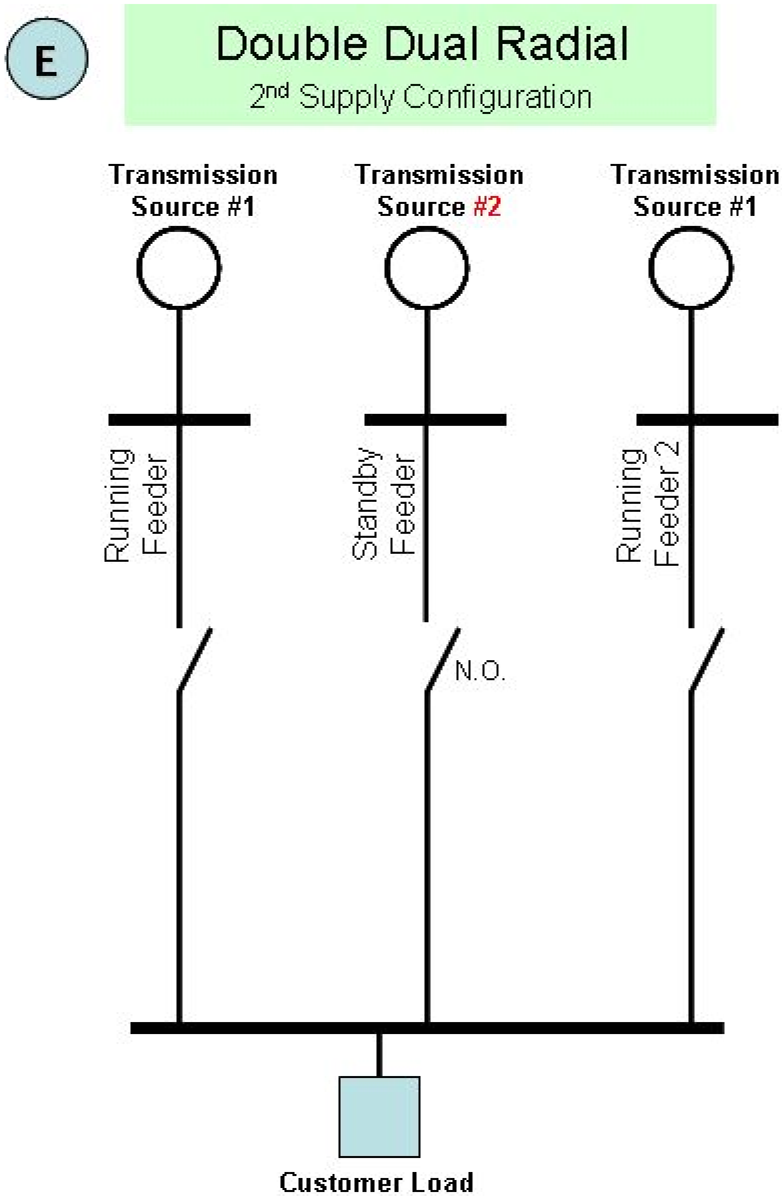

Figure 10: Vancouver Circuit Design – Double Dual Radial 2nd Supply Configuration

Figure 11 is the circuit schematic for Montreal. Hydro Quebec circuit design has four active feeders from different substations (~15 MVA / feeder @ 25 kV) and three load blocks per active feeder (~4 to 6 MVA / Block). Each block is backed up by one of the three other feeders through another load block. In emergency, the three remaining feeders can supply the total load of the four feeders. Ties between blocks must have the same load capacity as the main cable. No LV network is installed on Hydro Quebec urban network.

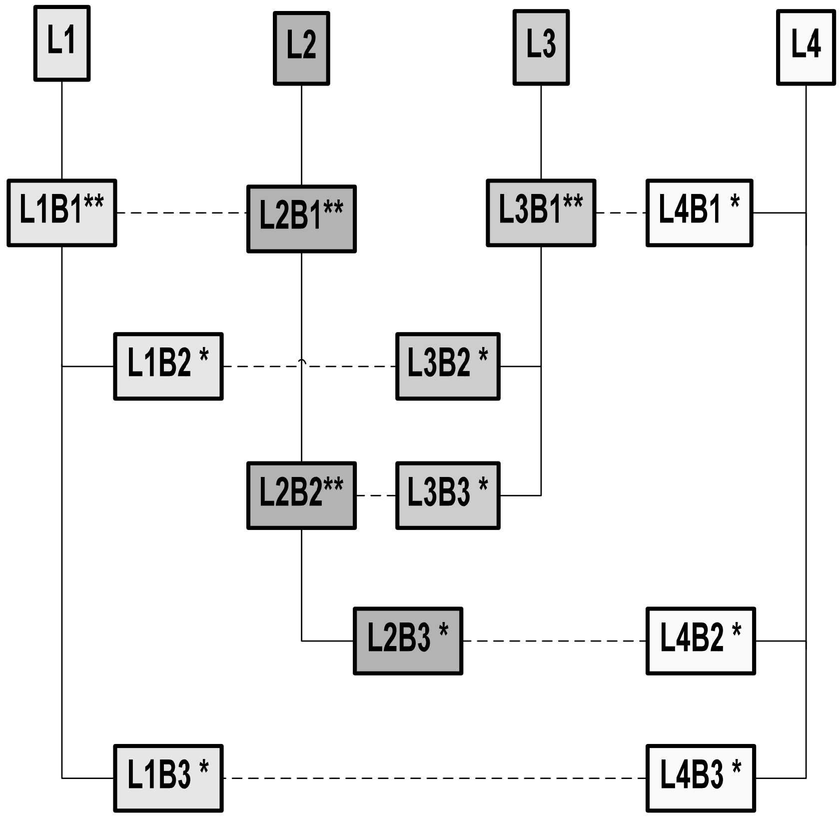

Figure 11: Montreal Circuit Design

Figure 12 and 13, below, are the circuit schematics for Toronto. Figure 12 is simplified to match the circuit schematics from the other cities and enable the comparison. Figure 13 is a detailed view of the Toronto electrical network.

In Toronto, each transmission station is fed by two different 230 kV or 115 kV transmission lines that are not necessarily from different generation facilities. The transmission station reduces the voltage to 27.6 kV or 13.8 kV which is at the distribution level that goes to the end consumer after going though another reduction at the distribution substation level. That provides at best N-2 reliability, but in most areas in Toronto it is N or N-1.

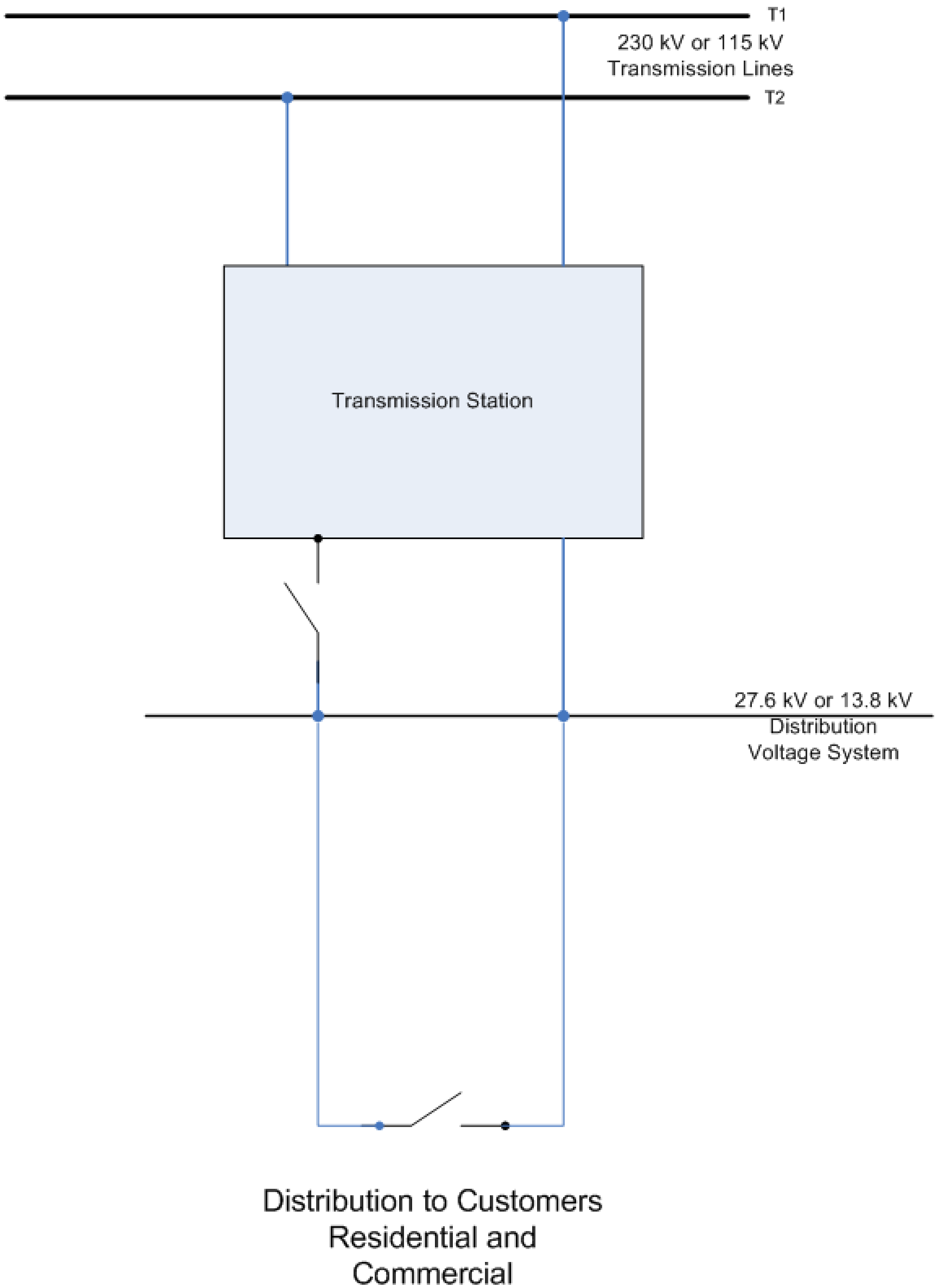

Figure 12: Toronto Circuit Design (Simplified)

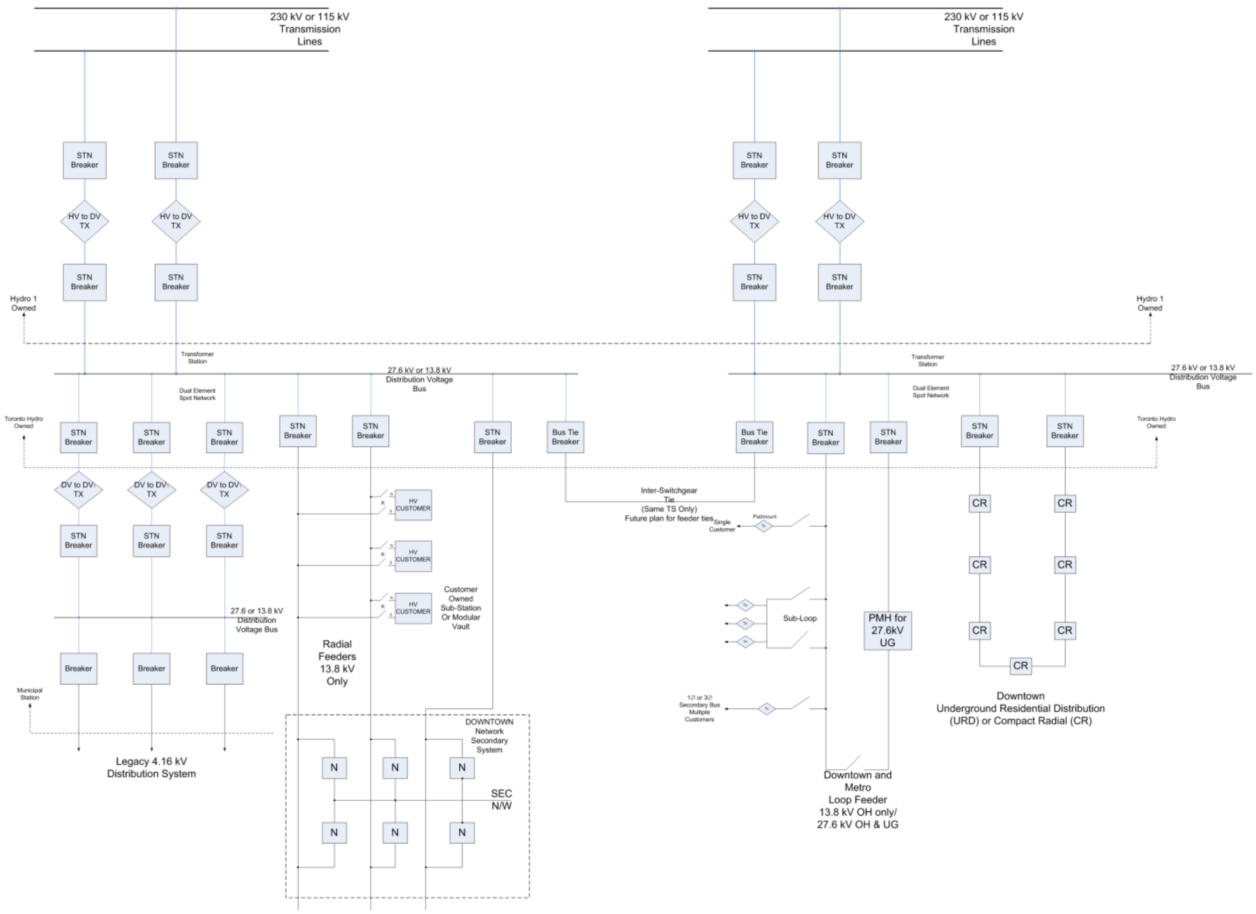

Figure 13: Toronto Circuit Design (Complex)

6.4. Electrical Network Design History

In each city, legacy had a big impact on the overall design. A short discussion of the history of the electric grid in each city is important to understand its electrical network design.

Vancouver

In Vancouver, during the late 1990s and early this decade, the growth rate caused BC Hydro to have to do a voltage upgrade in the city. As part of that upgrade and the density of the power consumption on the south end of Vancouver, a number of improvements were made in the overall redundancy in the system. Major substation re-design was done as part of this voltage upgrade. The process is about 99 percent complete now and will be finalized prior to the Olympics early next year. Vancouver is power constrained like Toronto, but unlike Toronto it can offer true N-3 reliability from generation source to end customer.

Toronto

In Toronto, at best, it is possible today to provide N-2 reliability from generation source to end customer. With only two major transmission links into the city,any higher level of reliability would require significant design effort. The recent addition of the Portlands generation facility (550 Mw) will offset, but not completely, the generation loss should either of the two major transmission links go down. To this end, the overall design reflects the limits of reliability that is available at the higher levels in the electrical system. Within those limits, the design in Toronto as taken on an N-2 design. The Toronto network was not designed initially to support the current density of the downtown area. Many changes to the network have been undertaken to deal with the growth in power consumption and the increase in density in the core city. Most of these changes were made to support specific new construction. While they were highly effective, they were to a large extent patches to existing infrastructure. The new underground cable available and Toronto Hydro's planned, related capital projects, combined with the temporary slow down in growth in Toronto, provides an opportunity to do a longer range review of the downtown grid design. This longer term review of the grid design should give Toronto Hydro the chance to do a significant redesign of the downtown network with the eye towards two-way power flow and ever increasing demand for power.

London and Paris

In Europe, the regulatory requirement for providing N-3 reliability comes mainly from the complete rebuild of the network after World War II by military engineers as part of the Marshall plan. In addition, as the network was expanded and improved in the 1960s and 1970s, it was the height of the Cold War and there was a high expectation that infrastructure would be a primary attack path. Both the generations of engineers in Europe were trained to design and build infrastructure that would survive a war, not just natural disasters.

Much of this high level of redundancy has masked the fact that much of the equipment is aging and facing replacement in London and Paris. Because of the strong government backing in Paris of EdF, equipment replacement and high redundancy in the network are core values in the city, and equipment is being replaced. In London, where the network is now owned by a foreign company and the strong regulatory drive by OFGEM (the utility regulator) to the lowest cost of power to the end customer, the reliability of the network is beginning to wane, and the end-customers are finally feeling the effects. On most mornings at least one train line in London suffers a power outage. London is struggling within their budget to make equipment replacement. Like Vancouver, London is also preparing for the Olympics and has asked for regulatory support for improving the grid and replacing aging equipment, and the results of this request will be known in October of this year.

Montreal

In Montreal, the city has grown outward more than upward, there were few constraints to the spread of the metro area, in addition the growth rate in Montreal has been far less than it has been in the other major cities. Vancouver has become a major gateway to Asia, Paris the gateway to Middle Eastern business, London the financial center of the European Union, and Toronto a major alternative to Wall Street. New York is the financial center of the world and still serves as a major immigration center. New York, London and Paris are all older high-rise cities than Toronto, meaning that more of the infrastructure was designed to support a higher power density when it was installed.

New York

New York was designed as a networked system under Manhattan from the beginning. No other choice was available at the time the system was designed; only distribution networks could provide the density of power that was required. In the 1930's when most of the tunnels were built and the initial network installed, modern equipment did not exist.

So Toronto does not have the long history of high density, nor the military design drive that its peers endured.

6.5. Electrical Network Design Impacts

In each case, the cities chose designs that made sense to their needs, In Paris and London, after World War II, the cost of installing the network was secondary and paid for out of different accounts. Maintaining that network is less costly than building it. Neither city could afford to build the same network today and pay for it at current rates. Double digit percentage rate increases would be required to support building these networks now. The current generation of engineers are working to maintain and extend the existing network designs, which are very well done. There will be a struggle in London when there is a requirement to increase power density, and to do so like Vancouver did with a voltage increase, will be a very complex dance. To run new circuits will also be a very complex dance. London has a major advantage that Toronto lacks – the subway system runs almost everywhere and makes a great corridor for new primary circuits. Both cities currently are working on distribution automation and smart grid programs that will allow demand side management to play a larger role in the energy supply.

Vancouver made clear decisions to improve their network based on the best engineering design practices in the mid-1990s. This long term program to improve both the ability to deliver more power to the dense downtown and improve reliability were core to this program, and both the provincial government and the management of BC Hydro made commitments to this improvement. It was a key part of the presentation to the Olympic committee on why Vancouver should be selected. Use of equipment that did not exist prior to the 1990s has allowed them to have a highly automated system that can provide immediate switching of power sources to many customers to improve reliability. This system will continue to be improved under their current smart grid plan. The current design did not take into account large amounts of embedded generation or the trend to renewables and Demand Side Response, both of which will be part of the smart grid program.

In New York the existing dielectric pipe network will probably be replaced in the next two (2) decades, both to improve maintenance costs and to open space for new substations and other infrastructure. This network has operated for over 70 years with a very high level of reliability. The voltage has been increased twice since the network was installed, allowing the city to continue to provide for the increasing power density required. In several of the largest buildings, multi-megawatt generation facilities exist that burn fossil fuels to provide electricity and district heating. The system in the Empire State Building provides over 50 megawatts of schedulable generation. Other buildings provide more than 200MW of embedded generation. Because of the density of the city most of the power will have to come from outside the city and not be generated internally. In New York, the formulation of a smart grid program is underway and has been presented for review at the last Modern Grid meeting. Based on comments at that meeting and from other sources, the program is being revised.

In all the cities, except Toronto there are at least three (3) independent transmission links into the cities, and at peak load, loss of any one of these links would not have a major impact on the city. This is not true of Toronto, which relies on two major substations to provide the bulk of the power to the city and loss of either one at peak load would have a major impact on the city. The recent addition of the Portlands generation facility (550 Mw) will offset, but not completely, the generation loss should either of the two major transmission links go down. The lack of a major third generation source until recently and no military drivers has influenced the design standards in Toronto, without a clear ability to truly provide N-2 or N-3. Without local back up generation, the overall network was designed to N-1 standards. For an N-1 network, the reliability is very good. Against the peer group, made up mostly of N-2 and N-3 grids, Toronto lags. Add the fact that historically compared to the peer group, Toronto has a lower population density in the city (except Montreal) and Toronto has a network that was designed for very different conditions than it faces today. This means that the Toronto Hydro smart grid program will have to address a lot more issues than in other cities to deliver the same results. Building in demand side management, embedded generation and more redundancy will be core parts of the smart grid program. The good news is that Toronto Hydro seems to be taking a holistic approach to the issue, rather than incremental programs that will result in costly rework.

6.6. Recommendations Based on Electrical Network Design Issues

Toronto Hydro can not go backwards and re-implement the whole grid. It is just not practical. They can go forward and implement a new style of grid. To do this, an analysis of the costs of re-implementing the grid should be determined as a baseline cost to compare options against. This analysis should include the transmission costs to get a new third source into the city and then a high level estimate for the cost of implementing an N-2 network for the whole city based on starting from 3 independent sources. This should be used as a baseline only.

The next step for Toronto Hydro should be to break the city into reliability zones. These zones would contain like customers who need specific levels of reliability. Using these zones the cost of a new grid design should be calculated for each area. For the areas that need reliability that requires a grid that has a higher level of reliability then N-1, rather than new transmission, the design should look at both storage and distributed generation as the improvement in reliability. Right now large scale storage of electricity is not really cost effective but storage costs are moving in that direction. One form of storage that is cost effective is thermal storage (heat and cold), looking at providing some peak relief with thermal storage and some eventual reliability improvement from electricity storage should be considered as part of this step. This step should be completed based on the best commercial technology available off the shelf today and based on what the technology will probably be in 10 years.

Comparing the distributed generation costs to the third source costs should provide a clear indication of whether one or the other is more cost effective.

There are too many single points of failure in the Toronto grid today. What ever gets done, the new design standard should be to the pad mount or pole mount distribution transformer level where the network should be a minimum of N-1.

To do this requires:

- Looping many circuits that are currently open loop.
- Addition of conductor and reclosers to support the looping design.
- Breaking large substations in to networks of smaller substations as substation repair is done (e.g. Manitoba Hydro’s substation in a box design).
- Considering changes to the requirements placed on new large building owners for provisions to support DG and equipment vaults.
- Potentially new rights of way and changes to the zoning requirements in the city.

A time line should be established for this work. A recommendation is fifteen (15) years from approval. This is about 1/3 the typical asset life for an asset in the city grid and is short enough to be a sustainable program, yet long enough so that a future bill to replace this infrastructure will not all come due in a single year. It is also a pace that should be supportable by the Toronto Hydro engineering team.

The installation of smart grid technology to provided additional sensing and control capability is an important step in the right direction as well. The Smart Grid rollout should correspond to the reliability improvement schedule.

7. RELIABILITY TRANSFORMATION ROADMAP

Reliability improvement at Toronto Hydro is a multi-year journey. It's a journey of people, processes, organizations, capital investments, integration and constraints that that requires both visibility and communication throughout Toronto Hydro. A Transformation Map is a practical, graphical representation of the reliability vision and the journey to achieve it. The process of transformation mapping is very adaptable and flexible.

The Transformation Map serves many purposes:

1. Communicate the vision and journey to the entire organization at a glance.
2. Plot strategies and initiatives and break these down into manageable timed pieces.
3. Identify conflicts and interdependencies across functions/business lines/stakeholders.
4. Ensure activities are all pulling in the same direction.
5. Key reference document that can be used during strategic business planning.
6. Use as input to budgeting process.

Figure 14 is the high-level Reliability Transformation Roadmap that has been developed for Toronto Hydro as a result of this analysis.

The transformation map has four tracks:

- **Physical Grid**: Activities related to the upgrade and maintenance of the equipment on the grid.
- **Smart Grid**: Activities related to Smart Grid program, that Toronto Hydro will need to implement because of the designed network limits and number of generation sources/feeds into Toronto.
- **People and Process**: Activities related to organization and process change or upgrades.
- **Renewable and Embedded Generation**: Activities related to actions needed to get ready for embedded generation and to limit the initial adverse impacts on reliability that it causes.

The roadmap also has three waves over ten years

- **Planning (2009 to 2010)**:
- **Foundation (2011 to 2013)**:
- **Steady State (2014 to 2018)**:

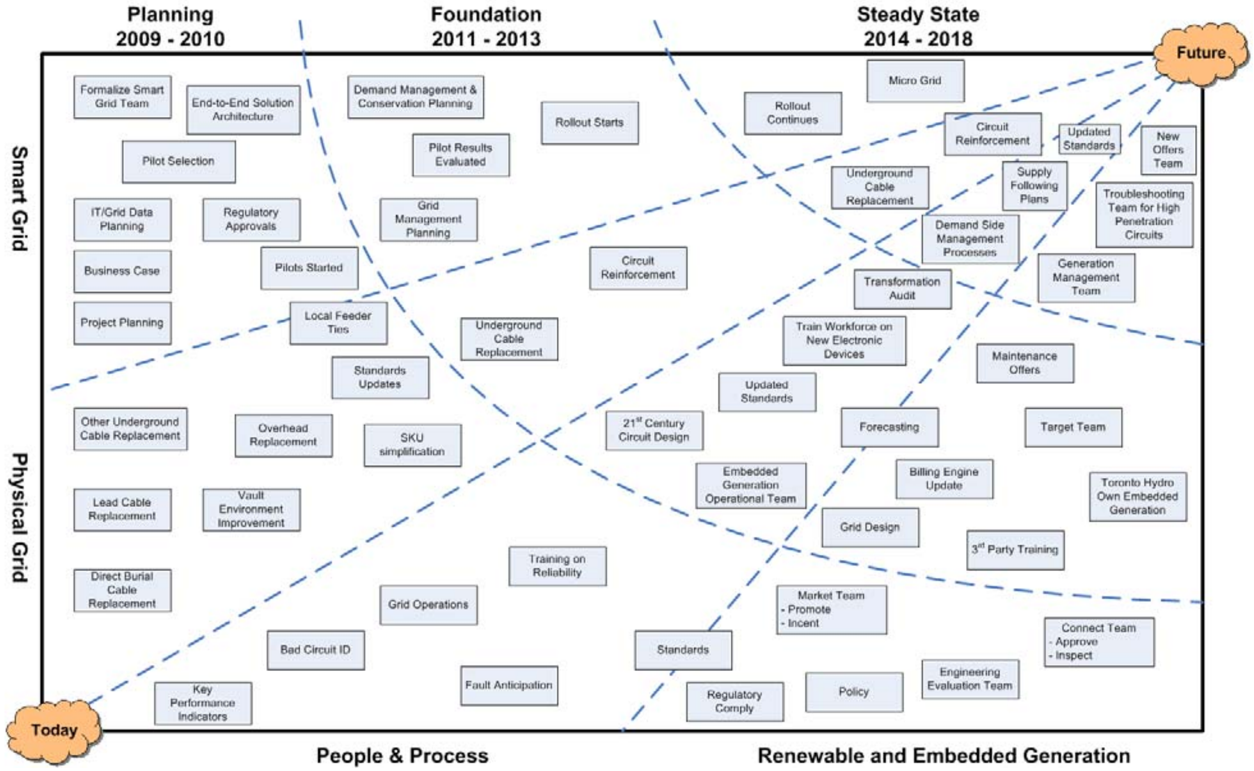

Figure 14: Toronto Hydro Reliability Transformation Map

The following subsections summarize the activities identified on the transformation map. We organized the sections by the there waves.

7.1. Planning (2009 to 2010)

7.1.1. Physical Grid

- **Direct Burial Cable Replacement:** Large amounts of older cable that was directly buried in accordance with best practice at the time have reached the end of their useful and safe life.
- **Lead Cable Replacement:** This older cable was the standard at the time it was installed and carried far more load in a smaller cable than other choices. This cable has reached the end of its useful life and is considered a hazard in many jurisdictions. Replacement of this cable helps maintain reliability and addresses environmental concerns.
- **Other Underground Cable Replacement:** There are other underground cables that have reached the end of their useful and safe life that need to be replaced. As part of replacing this cable, sizing or additional cables must be taken into account for future needs of the customers.
- **Vault Environment Improvement:** Many of the vaults are similar to vaults around the world; they maintain an environment that will support specialized utility equipment but not telecommunications and controls equipment. Improvement of this environment is a building block to providing better sensing and controls on the equipment installed in the vaults.

- **Overhead Replacement:** Much of the overhead in Toronto was installed as the neighbourhoods were built. The construction made sense when the equipment was originally installed, but over time, trees, building structures and other changes have put some of the equipment in poor locations. Additionally a portion of the equipment is beyond its useful life or improperly sized for current and future demand in the area. This project will maintain existing reliability and make future emergency replacement easier and faster to do should a storm damage equipment.

- **Local Feeder Ties**: The engineering design and installation of new local feeder ties to improve reliability and manageability of the electrical network. The local feeder ties when implemented in conjunction with smart grid will offer a number of options for better load and voltage management on the equipment

- **Standards Update:** Many of the design standards were selected before demand response and embedded generation were considered. To maintain reliability, some of these standards will need to be reviewed and revised.

- **SKU Simplification:** Over the years vendors and products have come and gone, but in many cases because the old equipment was installed in the grid, they have remained in the supply chain and procurement has bought replacements as needed. Simplification of the replacement strategy and the number of different items in the supply chain will help reduce the chance that something is out of stock which adds to the time to make repairs. While doing this simplification, working with a firm like Power Advocate to benchmark alternatives and select only the best of breed equipment is advisable.

7.1.2. Smart Grid

- **Formalize Smart Grid Team:** Because of the significant size of this effort, in order to move ahead with the planning activities, business case and regulatory filing. Toronto Hydro needs a sizable, dedicated team to address smart grid activities.

- **Business Case:** Toronto Hydro needs to develop a business case for the improvements of the grid by the inclusion of smart grid technologies. This includes the ability to support embedded generation, storage and other new technologies. It's needed for regulatory filings and the development of project planning details, budgets, etc.

- **IT/Grid Data Planning:** This activity will drive the Smart Grid Network design. The Smart Grid scenarios will derive certain equipment that will have to be deployed and communicated. The data volume, frequency and latency will drive the bandwidth and the communication network design.

- **End-to-End Solution Architecture:** Developing a solution that addresses the business case benefits and the smart grid scenarios. The solution needs to address the customer premise, the electrical grid, the telecom network, and back-end application footprint including the systems integration necessary to make the scenarios work.

- **Regulatory Approval:** Getting approval from the Ontario Energy Board (OEB) and others for the business case and specific objectives outlined in the business case and related filings.

- **Pilot Selection:** Based on the outcome of the business case, projects would be outlined that would meet the approved objectives. These would be proof of concept pilots with the goal of confirming what works and quantifies the benefits for Toronto.

- **Project Planning:** Creating an overall plan for the various smart grid related projects including resource needs, capital requirements, interdependencies, and timing.
- **Pilot Started:** This is the launch of the pilots that would validate the smart grid objectives based on the project plans developed above.

7.1.3. People & Process

- **Key Performance Indicators:** Review of the key performance indicators (KPI) for the reliability and determination if the right KPI's have been selected and if the right levels have been set. This review should determine if there are any changes and if there should be a trend line set for a specific metric.
- **Bad Circuit ID:** Currently (Feeder Experiencing Several Interruption) FESI-7 and FESI-12 and Worst Performing Feeder (WPF) are the key gates for which circuits are reviewed for major repair and/or improvement. This results in around 4 feeders that get reviewed by the cross-departmental team and between 10-16 feeders by component reliability team and recommended corrective actions. Other utilities use these methods as well as others. The first step in this effort is to look at how the bad circuits are identified and if there might be a more pro-active way to do this in light of the possible technology that smart grid may provide.
- **Fault Anticipation:** Detection and recognition of fault signatures to anticipate a fault, and perform predictive maintenance or isolation activities to prevent its occurrence. This technology is in use in two US utilities and in Japan.
- **Grid Operations:** Toronto Hydro can develop the organization and processes to allow for the operation of the grid in Toronto. Today the grid is maintained, not operated. There will be a need to create a group to manage the operations as smart grid and active measures are deployed in the grid. This group will have a big impact on the reliability of the grid. The group will be responsible for:
    - Security of the communications systems and controls
    - Operation of the sensors and controls
    - Monitoring the operations of the grid
    - Working with dispatch to assign the right workers to open issues
    - Making control decisions
    - Making demand response decisions
    - Working with others to maintain the grid and forecasting models
- **Training on Reliability:** Field and operations people will need training on what to look for with regard to reliability and operations of the grid. This training will have to change area by area as new technology is rolled out.
- **Standards:** Many of the operation standards need to be reviewed and potentially revised to deal with the changes to how Toronto Hydro will have to operate in the future.

7.1.4. Renewable & Embedded Generation

- **Regulatory Compliance:** Developing a plan that will meet the regulatory requirements as they are provided and meet the requirements of the Green Energy and Green Economy Act and other laws.

- **Policy:** The development of a policy on how to deal with embedded generation and distributed resources within the Toronto Hydro service territory to provide for an orderly integration of these resources.

- **Engineering Evaluation Team:** In order to understand the impact of larger embedded generation or large numbers of smaller generation sources in a concentrated area (e.g. a Green Subdivision), a team needs to be organized to review the impact on the grid from a reliability and stability stand point.

- **Market Team (Promote, Incent):** In order to get embedded generation installed and to help get it installed in places that offer the most benefit to Toronto Hydro's customers, some one needs to help customers and interested third parties navigate the process and promote doing so.

- **Connect Team (Approve, Inspect):** As the embedded generation is installed both the inter-connect safety and the quality of the connection can have an impact on reliability locally. A team needs to be available to review the requests and then inspect the results (at least until building codes catch up with this issue and building inspectors are trained).

7.2. Foundations (2011 to 2013)

7.2.1. Physical Grid

- **Underground Cable Replacement:** This is a continuation of the various underground cable replacements. This will be an on going effort for the foreseeable future.

- **Circuit Reinforcement:** This is a continuation of the overhead work. This will be an on going effort for the foreseeable future and possibly other programs in the physical grid.

7.2.2. Smart Grid

- **Demand Management and Conservation Planning:** Putting in a system or set of systems that would allow an operator to see what is going on in the grid, let them know what autonomous control actions have been taken and where help is required, as well as taking control actions is a key step in the using the smart grid for reliability reasons. That includes integrated demand offers, smart appliances, smart homes, home displays, home energy system and many others.

- **Grid Management Planning:** Putting a system or a set of systems that will help the distribution operators to manage the future / smart distribution grid. That includes vault monitoring, power loss prevention, fault indicators, integrated outage management, feeder automation, distribution substation monitoring, energy storage, distributed generation, and many others.

- **Pilot Results Evaluated:** Once the pilots have run to conclusion, there are lessons that can be learned and information fed back to the vendors and others involved. The results evaluation is a key step in moving from pilot to full scale roll out or not, and making the necessary adjustments/corrections to plans.

- **Rollout Starts:** For those pilots that meet expectations, then a rollout should be started. This is when real benefits will be recognized.

7.2.3. People & Process

- **21st Century Circuit Design:** If Toronto Hydro is going to take advantage of smart grid technologies then a basic template circuit should be developed as a baseline for designers and engineers to use as a template for circuit rebuilds and extensions. This also will help Supply Chain and others to determine what needs to change in their areas as well.
- **Embedded Generation Operational Team:** In time there should be enough embedded generation within the city of Toronto that it will become noticeable when running. To keep this generation running at the right times and communicate with the Independent Electrical System Operator (IESO) on the status of the most significant units, an operations team needs to be created.
- **Updated Standards:** As work on the 21st Century Circuit and the Embedded Generation Operations Team continue, some standards will have to be revised, some several times, as thresholds change and Toronto Hydro determines how to best operate with more and more embedded generation and demand response.
- **Forecasting:** As the grid becomes more complex with embedded generation and electric vehicles, it will be important to have a good forecasting system not only at a city level but at a circuit and feeder level. This will help avoid issues with overloaded circuits and give the ability to send the right signals to devices connected to the circuits. This forecasting system will evolve as the embedded generation and electric vehicles grow.
- **Train Workforce on New Electronic Devices:** Many of the devices that will be deployed in the network are not part of the current training programs. Training programs will have to be updated and additional training will be required to support proper operation and maintenance.
- **Transformation Audit**: Conduct a formal audit of the transformation process against the goal that where set for the program.

7.2.4. Renewable & Embedded Generation

- **Grid Design:** As embedded generation is installed or planned it will have an impact on the grid design, conductor sizes, voltage transformers, protection schemes and other items may need to be reviewed for larger embedded sources and as the penetration increases, the aggregation may have design impacts to maintain reliability.
- **3rd Party Training:** As third parties start installing and maintaining embedded generation they will need an understanding of the interconnect rules, the way that Toronto Hydro interfaces with them, how they interface with the IESO and others. Without this training it will be harder to move the level of embedded generation forward.
- **Billing Engine Update:** As embedded generation becomes more common, there will be a point where the manual work around to create a correct bill will be more effort than updating

the billing engine to provide an automated bill and to provide an audit level of tracking of the billing changes based on power produced by the customer.

- **Toronto Hydro Own Embedded Generation:** There may be a need for Toronto Hydro to either install or have installed embedded generation that they either own or operate or contract for operation of. The determination of this need, the locations that would best help reliability and the structure of any involvement all need to be developed and worked out in compliance with regulatory rules and existing laws.
- **Maintenance Offers:** Most home owners and owners of smaller embedded generation do not maintain their systems at peak operating efficiency and in fact many fail when called upon after a period of disuse (e.g. spring and fall). It is important to maintain the capability to operate. Until there is a strong third party maintenance capability that generation owners can use, it may be necessary for Toronto Hydro to offer this service. For some customers it may be necessary to offer this service for the foreseeable future.
- **Target Team:** This team would look for the right locations to place generation in the city and work with the marketing team to get people interested in putting generation in these locations.

7.3. Steady State (2014 to 2018)

7.3.1. Physical Grid

- **Underground Cable Replacement:** This is a continuation of the various underground cable replacements. This will be an on going effort for the foreseeable future.
- **Circuit Reinforcement:** This is a continuation of the overhead work. This will be an on going effort for the foreseeable future.

7.3.2. Smart Grid

- **Rollout Continues:** Since these are large projects, they will not complete for all the customers for many years. The rollouts will continue over this time period. In many cases, as the rollout continues, improvements will be made.
- **Micro Grid:** Control algorithms, devices, and standards that control the creation and operation of a Micro Grid embedded in the utility grid. This can take the form of a Virtual Power Plant (coordination of resources from a group of distributed generation), community power (group of customers managing their own power), and intentional islands. This recognizes the wide-scale deployment of distributed generation and energy storage that has occurred.

7.3.3. People & Process

- **Demand Side Management Processes:** The implementation of Demand Side Management will require the development of processes that will allow the orderly operation of demand side management and the equipment that supports it. Programs/choices must be simplified for the customer.
- **Supply Following Plans:** As the amount of renewable generation grows, there will be a point where there will be a need to manage demand to match supply, both locally and

globally. This will require both longer term forecasting, and short quick turn around processes for dips in supply.

- **Updated Standards:** As things continue to evolve, standards will have to continue to evolve as well.

7.3.4. Renewable & Embedded Generation

- **Generation Management Team:** As the penetration of embedded generation rises, it will become important to provide signals to run or not to run, to the sources. This becomes even more important when Plug-in Hybrid Electrical Vehicles (PHEV) are included in the mix. There will need to be a team that can provide this guidance to the devices in the field. It is an open question "Is this better done by the LDC or the IESO?" that will need to be resolved. Is the IESO equipped and ready to deal with potentially thousands of sub-1 kW sources?
- **Troubleshooting Team for High Penetration Circuits:** The addition of embedded generation and PHEV will not be even across the Toronto Hydro territory. Penetration will be by demographics group, in some areas there will be almost none and in others it will occur on almost every connection to a customer. This unevenness will have a negative impact on reliability that will need troubleshooting support from people who have a background in embedded generation and reliability.
- **New Offers Team:** To continue to drive additional embedded resources (e.g. storage, generation and demand response), it will be important to innovate and provide a reason customers want to participate. This team will continue to drive new offers to the customers to get additional participation and maintain existing penetration.

7.4. Specific Recommendations Related to the Roadmap

7.4.1. Physical Grid

1. Accelerate the existing 10 year replacement program by at least 4 years. It is probably too late to bring 2011 into 2010 planning but in 2011 Toronto Hydro should accomplish all of the 2011 and 2012 goals. The same doubling up of the work should be done in the following 3 years. This will accelerate the program to 6 years rather than 10 years.

2. Find the families of equipment that are failing and accelerate the replacements. With over half of all outages coming from defective equipment, it should be possible to identify the families of equipment with a failure rate that is above average and the Failure Modes Effects Analysis indicate that the reason for failure rests with the equipment itself. The conductor so identified is already in the 10 year program. This recommendation is for the rest of the equipment not identified in the existing program.

3. Build a reliability zoning map for the city with target SAIDI by zone. The zone with the lowest reliability should probably target a SAIDI of not more than 80 minutes a year in 2012 with a long-term goal of 25 minutes. The highest reliability zones should probably target a SAIDI of 5 minutes or less a year. This would bring the financial district into line with the global financial centers and make Toronto a desirable city for new financial institutions or off shore institutions looking for a North American base.

4. Rework design standards for circuits to minimize changes in conductor size from end to end of the circuit and also to minimize voltage changes. Ideally to support large amounts of distributed generation and reclosing to back feed circuits the conductor and the voltage should be the same from end to end. This way the capacity of the circuit remains the same for the full length of the circuit.

5. Look at the condition of the vaults and determine if there are vaults that need better pumps and drainage or better ventilation. With more power running thru the equipment in the vaults, the environments of the vaults will become more important over time to the life expectancy of equipment. It may be useful to add web-cameras to the vaults to be able to look at the condition of the vaults from time to time and using pattern matching software – still photos can be compared for differences day to day. In London use of these cameras is done for the following reasons:
   - To use IR for thermal imaging of the equipment to find overheating before it becomes a problem
   - To IR to find animals and other life in the vaults
   - Use them to look at a painted pattern on the wall so that if water gets into the vault – the pattern will be obscured and the system will alarm.

6. Look at the Georgia Power methods for long underground pulls and see they fit the requirements for Toronto to reduce splices in any of the circuits. Georgia Power has done single pulls of approximately 400 meters and that has reduced their splice counts in areas by as much as 75 percent from 10 years ago. Note that it takes special equipment and training to do this.

7. Look at any TTC expansion as an opportunity to get utility tunnels at the same time. Tokyo did this in much of the city and it has resulted in excellent access to utility equipment. The added cost was minimal when compared to doing a single purpose utility tunnel.

8. Look at some Toronto Hydro owned or co-owned distributed generation in key areas of the city. So that the generation can be targeted to the right locations and the right phase to add reliability and system security to the right circuits.

9. While the transmission system is not the issue for Toronto, knowing the cost of a third source for the city and the cost of adding the medium and low voltage circuits to get to N-2 would be a good benchmark to compare distributed resources against when planning investments for reliability and power quality.

7.4.2. Smart Grid

1. Building a matrix of what information is required to monitor asset condition and moving to condition based maintenance based on monitoring, not visual inspection, is a key benefit of smart grid. To do this Toronto Hydro needs to determine what information and on what frequency that information is useful to provide the right inputs to the maintenance model. Toronto Hydro has already participated in a first step with their work on CEATI projects 3036 and 5057. Now they need to take the next step and make the sensor placement specific to their needs. This study should be completed as a key step in prioritizing sensor placement as part of the smart grid program. Moving to monitored condition based maintenance is one of the best ways to reduce defective equipment SAIDI times. Coordinating sensor placement

with the smart grid program will allow both to take full advantage of the sensors placed and the crews deployed to place them.

2. Looking at how the demand response program should be targeted for commercial and industrial customers will be the key to reliability in the grid. If there is enough monitoring of phase imbalance and segment loading, then targeting specific locations for demand side management will make a big difference in remaining life on that equipment. While this should not be used as a long term solution, there should be a regulatory way to target an area for a reasonable period of time for reductions with incentives to allow for upgrading equipment as load grows. This sort of targeted reduction should also be allowed by regulation to help balance the impact of variable distributed generation like solar and wind within the city.

7.4.3. People and Process

1. Adding staff to support those programs while dealing with the aging workforce issues will be very important. Improving and supporting a local utility electrical engineering education program is critical to being able to do this staff increase. Right now in Canada there is a salary war for experienced people as retirements increase. Budget for this should be targeted for 2010.

2. Contractors used by Toronto Hydro will need to also upgrade skills and processes to support the changing requirements in the grid. Toronto Hydro may have to create a group of contractors that are certified to do work and are under Master Services Agreements to make this work. Keeping a stable and competitive set of contractors who have the right skills to help will make a difference in the rate at which Toronto Hydro can implement these changes and accelerate their programs. This program should be started as soon as possible with the goal of 3 to 4 qualified contractors in the program by the end of the first quarter of 2010. Toronto Hydro may want to coordinate their program with other utilities so that the contractors have a common set of standards and practices to work from. The program will take significant work as Toronto Hydro moves to smart grid.

3. IEEE1547 – the key standard for interconnection of distributed generation is inadequate for large numbers of distributed generation units to be installed with. The IEEE PES is looking at revising that standard. It would be useful if Toronto Hydro was part of that working group and the IEEE PES working groups on power quality and reliability.

7.4.4. Distributed Generation

1. There needs to be regulation that allows Toronto Hydro to disconnect un-registered distributed generation and those units that fail to meet minimum safety standards. Beyond that the regulation should encourage distributed generation, cutting as much red tape as possible.

2. Toronto Hydro should have a fund that can be used for special incentives to add distributed generation in areas where it will help the most with reliability and power quality. This fund should allow them to target 10 to 15 MW a year minimum of distributed generation or storage that either would be owned by Toronto Hydro or subsidized by Toronto Hydro. This fund should be made available as soon as possible and if the program is successful, then is should be reviewed for expansion, not only in the city but in all of Ontario.

3. Not all distributed generation can be renewable variable (e.g. wind and solar) generation. Some of what needs to be installed is conventional fossil or biomass based generation that will allow it to run when needed to support reliability and power quality. This generation should not be seen as a replacement for base-load, but it should be available to run as needed to support the customers of Toronto Hydro.
4. Long term the goal should be a minimum of 35 percent of peak power requirements for Toronto be generated in the city. Of this, 10 percent of the total should be developed for reliability and power quality at a minimum.

8. FUTURE STUDIES

In conducting this study it became obvious that one of the limits to improved reliability in Toronto is the fact that there really are only two independent sources of power to the city that are large enough to support the daily needs of the city, and that any changes to the electrical network done below this level was still subject to these limits in the long run. Ontario is in the process of a major transformation of generation and power consumption in the province (conservation and demand management, embedded distributed generation and energy storage, renewable) and this set of changes is being put in place based on a single plan. It would be useful to look at the following future scenarios for Ontario and its power provision for Toronto:

1) The development of an additional independent power source for Toronto from outside of the city (the option of distributed generation is discussed in 2) below), whether a substation to support new wind sources, or other renewables, or a feed on the new transmission link from Quebec. What would be the difference if a new major substation network was installed in the GTA that would provide another external independent source of electricity? Two subsets should be looked at:
    a. A single major substation probably in the 750 – 1500 MVA size.
    b. A network of smaller substations all fitting a single design with interchangeable components that would all be fed from this new transmission link, this network of substations would be in the 125 to 300 MVA size.
2) The development of 600 to 900 MVA of embedded resources in the city itself. The resources should for the purposes of the study be broken into three groups of roughly equal size:
    a. Demand response that is schedulable and callable
    b. Renewable generation – probably mostly large wind off shore in Lake Ontario, or distributed generation, as identified in c.) below
    c. Conventional generation in the city itself (e.g. Heran Co-Gen and existing backup generation). A large amount of back up and emergency generation already exists that is not coordinated, so the absolute increase would be less than expected. The recent addition of the Portlands generation facility can partially offset the loss of either of the two major transmission feeds. Given this limitation, additional conventional generation is an option, however, recent Ontario legislation makes a.) and b.) above, more likely solutions.
3) A clean sheet redesign of the downtown network. What would the downtown network look like if it were designed to support the planned density of development downtown and built from scratch.

All three of these studies would provide useful information to inform the debate on what should be done to support the City of Toronto and the Province of Ontario into the mid-century.

Within Toronto Hydro, there are also a number of studies that should be conducted or expanded:

1) Distributed Generation for Reliability Study. Which locations exist in Toronto where larger schedulable distributed generation could be installed? This should include looking at co-generation of heat and possibly other by-products of the generation. This detailed study should be done in conjunction with the City's Economic Development Division and should determine which businesses have a need for higher power reliability and would therefore be likely to participate in the projects once launched.

2) Distributed Storage for Reliability Study. Where in the city might multi-megawatt batteries be installed, understanding that today most battery chemistries have drawbacks that limit safe location of the batteries and supporting equipment?

3) Single Phase Renewable Generation Forecast Maps. Based on city demographics, what are the most likely locations for distributed renewable generation to get installed in the city? Since it takes people with capital to invest, some areas are more likely to get large amounts of distributed generation than others. Also city ordinances may limit the locations that have solar generation by limiting the amount of tree trimming and removal that can be done to allow solar to work. These two factors and more play into the likely locations and the areas where reliability may be impacted first by renewable generation. In most cases as renewable generation rises, the utility has to play catch up on relay schemes and other changes, leading to the loss of reliability in those areas for a period of time. As the utility catches up, then reliability returns to its prior levels. Knowing where renewables are likely to be installed means that changes can be planned into the grid.

4) Sequence Planning Study. Which smart grid and physical grid changes are most likely to have the highest impact on reliability and is there an order of installation that changes the impact of each technology on reliability? Could one order of projects provide more reliability earlier than another order of installations? No one has done enough actual smart grid work to have a good set of industry best practices.

9. APPENDIX

9.1. Appendix A: Detailed Analysis of the Canadian Cities (Vancouver/Montreal/Toronto)

Based on the reliability data received from Vancouver and Montreal we were able to do a more detailed analysis at the interruption outage codes.

These analyses include:

- Vancouver / Montreal / Toronto (Metro Area) – Canadian Cities Reliability Data Comparison – including customer min out and customer interruptions.
- Vancouver / Montreal / Toronto (Downtown Area) – Canadian Cities Reliability Data Comparison including customer min out and customer interruptions.
- Vancouver / Montreal / Toronto SAIDI and SAIFI - Metro and Downtown comparison
- Toronto metro / Toronto downtown Reliability Data Comparison including customer min out and customer interruption.

9.1.1. Vancouver/Montreal/Toronto (Metro Area) – Canadian Cities Reliability Data Comparison

The fact that we received detailed outage data with outage coding from all three major Canadian cities allowed us to conduct a detailed analysis at the outage coding level. Because all three cities are members of CEATI, they agreed to the CEATI definitions and coding of outage causes – that made the comparision more straightforward, no mapping was needed. The next three Tables group the customer minutes out and customer interruptions for Toronto, Vancouver, and Montreal based on the interruption causes.

Cause	Toronto Metro Area			
	Cust Min Lost	% of Cust Min Lost	Customer Interruptions	% Customer Interruptions
ADVERSE ENVIRONMENT	2,355,064.00	4.63%	16,483.00	1.37%
ADVERSE WEATHER	4,471,213.00	8.79%	87,054.00	7.23%
DEFECTIVE EQUIPMENT	26,401,204.00	51.90%	582,999.00	48.45%
FOREIGN INTERFERENCE	4,526,966.00	8.90%	119,985.00	9.97%
HUMAN ELEMENT	293,616.00	0.58%	23,690.00	1.97%
LIGHTNING	3,798,092.00	7.47%	51,526.00	4.28%
LOSS OF SUPPLY	1,131,081.00	2.22%	70,382.00	5.85%
SCHEDULED OUTAGE	1,521,208.00	2.99%	18,355.00	1.53%
TREE CONTACTS	5,128,418.00	10.08%	94,828.00	7.88%
UNKNOWN / OTHER	1,246,252.00	2.45%	137,970.00	11.47%
	50,873,114.00	100.00%	1,203,272.00	100.00%

Table 10: Toronto Metro Area Interruption Data Mapped to the Causes

Cause	Vancouver Metro Area			
	Cust Min Lost	% of Cust Min Lost	Customer Interruptions	% Customer Interruptions
ADVERSE ENVIRONMENT	3,727,771.00	10.19%	12,642.00	6.58%
ADVERSE WEATHER	2,796,894.00	7.65%	10,562.00	5.50%
DEFECTIVE EQUIPMENT	6,852,878.00	18.74%	29,265.00	15.23%
FOREIGN INTERFERENCE	3,444,958.00	9.42%	18,728.00	9.74%
HUMAN ELEMENT	0.00	0.00%	0.00	0.00%
LIGHTNING	0.00	0.00%	0.00	0.00%
LOSS OF SUPPLY	1,434,254.62	3.92%	24,510.00	12.75%
SCHEDULED OUTAGE	0.00	0.00%	0.00	0.00%
TREE CONTACTS	6,993,707.00	19.12%	44,771.00	23.29%
UNKNOWN / OTHER	11,326,089.92	30.97%	51,720.00	26.91%
	36,576,552.54	100.00%	192,198.00	100.00%

Table 11: Vancouver Metro Area Interruption Data Mapped to the Causes

Cause	Montreal Metro Area			
	Cust Min Lost	% of Cust Min Lost	Customer Interruptions	% Customer Interruptions
ADVERSE ENVIRONMENT	0.00	0.00%	0.00	0.00%
ADVERSE WEATHER	2,435,963.66	1.71%	47.00	1.56%
DEFECTIVE EQUIPMENT	50,610,556.91	35.58%	806.00	26.79%
FOREIGN INTERFERENCE	4,187,491.66	2.94%	77.00	2.56%
HUMAN ELEMENT	15,328,989.73	10.78%	124.00	4.12%
LIGHTNING	463,758.61	0.33%	29.00	0.96%
LOSS OF SUPPLY	9,623,393.22	6.77%	118.00	3.92%
SCHEDULED OUTAGE	36,614,064.46	25.74%	1,387.00	46.10%
TREE CONTACTS	6,985,805.12	4.91%	69.00	2.29%
UNKNOWN / OTHER	15,985,484.12	11.24%	352.00	11.70%
	142,235,507.49	100.00%	3,009	100.00%

Table 12: Montreal Metro Area Interruption Data Mapped to the Causes

To compare the three cities, we've plotted the % customer minutes out and % customer interruptions as shown on the following two graphs.

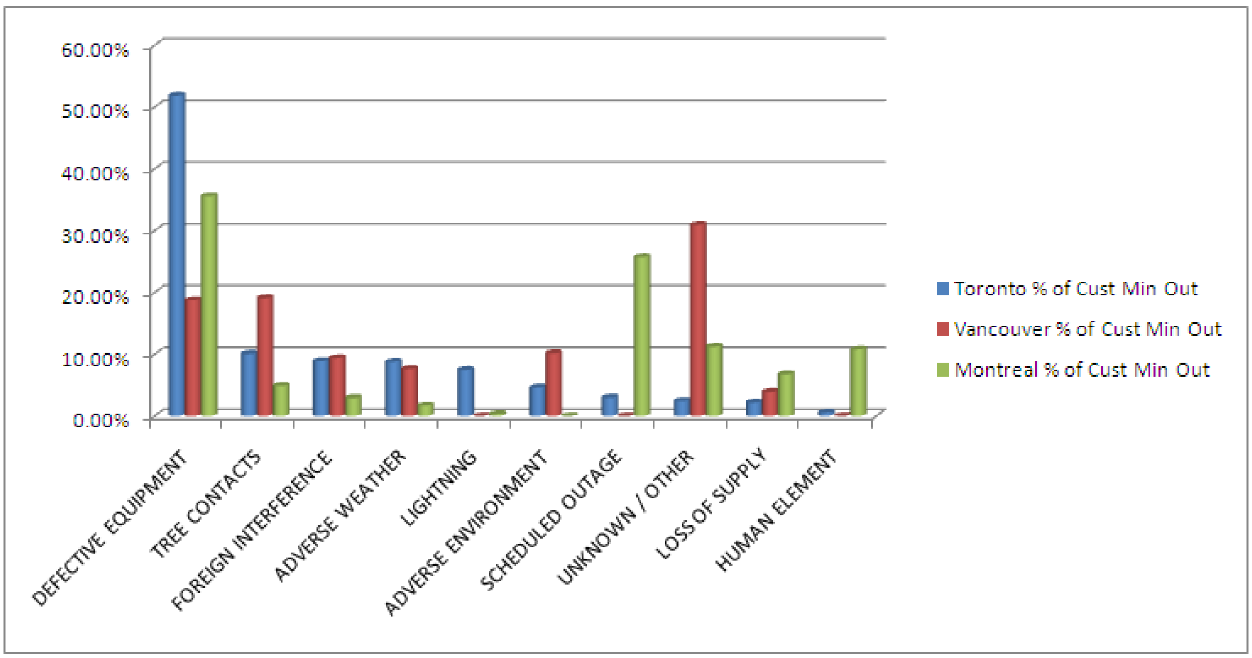

Figure 15: Canadian Cities Metro Areas - % Customer Minutes Out Comparison

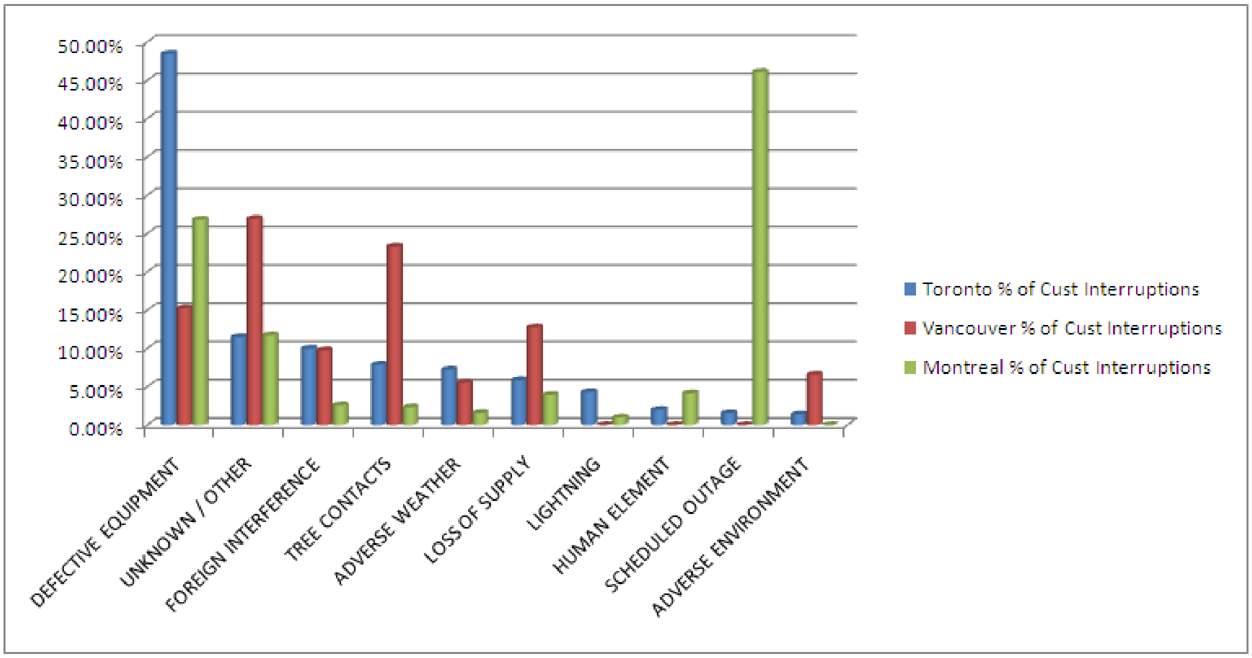

Figure 16: Canadian Cities Metro Areas - % Customer Interruptions Comparison

Observations:

1. Even with common definitions it is possible to classify outages in different ways, for example equipment that is defective, but actually failed because of a lightning strike might be classified as defective equipment in one case and lightning in another, depending on when the equipment actually failed and when it was actually replaced. In the midst of a storm recovery it is likely the equipment would be classified as lightning related. In cases of smaller storms with few outages, it seems to be classified as defective equipment.
2. 51.9% of Toronto Hydro interruptions are caused by defective equipment. Those interruptions are not affected by the electrical network infrastructure (underground or overhead) or climate.
3. Toronto Hydro's second largest interruption cause (10%) is Tree Contacts.
4. Similar to Toronto, large percentage of Vancouver and Montreal interruptions are cause by defective equipment – 18.75% and 35.58% respectively.
5. Montreal does not have problems with tree contacts as Vancouver and Toronto. 19.12% of Vancouver interruptions are caused by tree contacts and they are much more frequent than Toronto.
6. Vancouver data has 30% of the events categorized as Unknown/Other. We may want to consider normalizing this consistent with Toronto and Montreal, and recalculate the interruption cause percentages.
7. Montreal has a large percentage (46%) of interruptions for Scheduled Outages. If these outages are for maintenance, it appears that based on Defective Equipment (35%), it's ineffective. In Montreal, work rules are such that it is easier to do work on de-energized

equipment than on energized equipment, and at the lowest levels of the network enough protective devices do not exist to allow re-routing of power to all customers.

8. Vancouver does not record any Scheduled Outages, under the agreed-to regulations scheduled outages are not counted against SAIDI.

9. Lightning outages are much more frequent in Toronto compared to Vancouver and Montreal. It makes sense for Vancouver but it is questionable that Montreal does not record more outages as a result of lightning. Some of the defective equipment issues probably could be traced to the lightning strikes.

According to a Lawrence Berkeley National Laboratory (LBNL) study, “Understanding the Cost of Power Interruptions to U.S. Electricity Consumers,” funded by the U.S. Department of Energy (DOE) after the August 2003’s blackout in the United States and Canada – 32% of the outages caused by vegetation/trees, 31% by equipment failure, 19% by miscellaneous causes and 18% by animals. Based on this study Toronto is doing well in comparison to vegetation (10.08% of Toronto outages are cause by tree contacts), but when it come to equipment failure Toronto Hydro is more than 20% higher than the average (51.9% of Toronto outages are caused by equipment failure)

The study also looked at the overhead components failure rate, see Table 13.

Component	%
Pin Insulators	33%
Dead Ends	19%
Lightning Arrestors	14%
Insulators	12%
Misc. HW	8%
Cut Outs	6%
Grounds	3%
Switches	2%
Connectors	1%
Crossarms	1%
Non-Utility Electrical	1%

Table 13: Overhead Component Failures

Toronto Hydro has done a very similar analysis – see Appendix B section 9.2.3 “Five-Year Historical Reliability Performance Indicators”. Toronto Hydro Electric System Limited (THESL) farther categorizes the Defective Equipment cause code by the system type: Overhead Equipment, Underground Equipment, and Station Equipment. The top contributors to for defective equipment in 2008 were: Underground Cable (18%); Overhead Switches (9%); Overhead Lighting Arrestors and Insulators (6%); Elbows, Terminators and Potheads (4%).

Chart 5 and 6 in “Five-Year Historical Reliability Performance Indicators” document (see Appendix B section 9.2.3) shows the performance of the Overhead Equipment for 2004-2008, and Chart 7 and 8 shows the performance of the Underground Equipment for 2004-2008.

9.1.2. Vancouver/Montreal/Toronto (Downtown Area) – Canadian Cities Reliability Data Comparison

Because of the level of detail available in the data provided it was possible to segment the business district in each of the three cities and compare only the core downtown area – the circuits that serve the banking, financial and business area in each city. This is a key indicator that many large businesses look at when they are looking to locate major new offices or when they are looking to move their headquarters. In all three cases, the circuits serving this area are almost entirely underground and have a different design than most of the rest of the city. Because of the critical need for power (including major hospitals) in these areas, the networks have a tendency to have a design that provides a higher level of reliability.

Based on the detailed data we received for Vancouver and Montreal, we compared the reliability data at the interruption causes level for Vancouver, Montreal, and Toronto downtown areas (The codes and definitions are based on the Distribution Service Continuity Committee of CEA, same as Toronto Hydro data). The next three Tables group the customer minutes out and customer interruptions for Toronto, Vancouver, and Montreal based on the interruption causes.

	Toronto Metro Area			
Cause	Cust Min Lost	% of Cust Min Lost	Customer Interruptions	% Customer Interruptions
ADVERSE ENVIRONMENT	268,430.00	15.20%	1,174.00	4.46%
ADVERSE WEATHER	1,863.00	0.11%	999.00	3.79%
DEFECTIVE EQUIPMENT	1,067,304.00	60.45%	11,403.00	43.29%
FOREIGN INTERFERENCE	101,429.00	5.74%	1,276.00	4.84%
HUMAN ELEMENT	0.00	0.00%	0.00	0.00%
LIGHTNING	0.00	0.00%	0.00	0.00%
LOSS OF SUPPLY	0.00	0.00%	0.00	0.00%
SCHEDULED OUTAGE	11,202.00	0.63%	1,867.00	7.09%
TREE CONTACTS	304,369.00	17.24%	4,315.00	16.38%
UNKNOWN / OTHER	11,031.00	0.62%	5,305.00	20.14%
	1,765,628.00	100.00%	26,339.00	100.00%

Table 14: Toronto Downtown Area Interruption Data Mapped to the Causes

Cause	Vancouver Metro Area			
	Cust Min Lost	% of Cust Min Lost	Customer Interruptions	% Customer Interruptions
ADVERSE ENVIRONMENT	2,136,803.00	18.94%	3,864.00	8.29%
ADVERSE WEATHER	1,818,128.00	16.11%	8,378.00	17.98%
DEFECTIVE EQUIPMENT	1,432,111.00	12.69%	3,913.00	8.40%
FOREIGN INTERFERENCE	491,526.00	4.36%	2,475.00	5.31%
HUMAN ELEMENT	0.00	0.00%	0.00	0.00%
LIGHTNING	0.00	0.00%	0.00	0.00%
LOSS OF SUPPLY	0.00	0.00%	0.00	0.00%
SCHEDULED OUTAGE	0.00	0.00%	0.00	0.00%
TREE CONTACTS	113,285.00	1.00%	186.00	0.40%
UNKNOWN / OTHER	5,292,577.00	46.90%	27,790.00	59.63%
	11,284,430.00	100.00%	46,606.00	100.00%

Table 15: Vancouver Downtown Area Interruption Data Mapped to the Causes

Cause	Montreal Metro Area			
	Cust Min Lost	% of Cust Min Lost	Customer Interruptions	% Customer Interruptions
ADVERSE ENVIRONMENT	0.00	0.00%	0.00	0.00%
ADVERSE WEATHER	0.00	0.00%	0.00	0.00%
DEFECTIVE EQUIPMENT	2,295,632.65	31.30%	89.00	36.18%
FOREIGN INTERFERENCE	255,794.01	3.49%	5.00	2.03%
HUMAN ELEMENT	1,515,737.98	20.66%	8.00	3.25%
LIGHTNING	0.00	0.00%	0.00	0.00%
LOSS OF SUPPLY	0.00	0.00%	0.00	0.00%
SCHEDULED OUTAGE	2,494,104.30	34.00%	129.00	52.44%
TREE CONTACTS	32,958.01	0.45%	0.00	0.00%
UNKNOWN / OTHER	740,888.94	10.10%	15.00	6.10%
	7,335,115.89	100.00%	246	100.00%

Table 16: Montreal Downtown Area Interruption Data Mapped to the Causes

To compare the three cities, we've plotted the % customer minutes out and % customer interruptions as shown on the following two graphs.

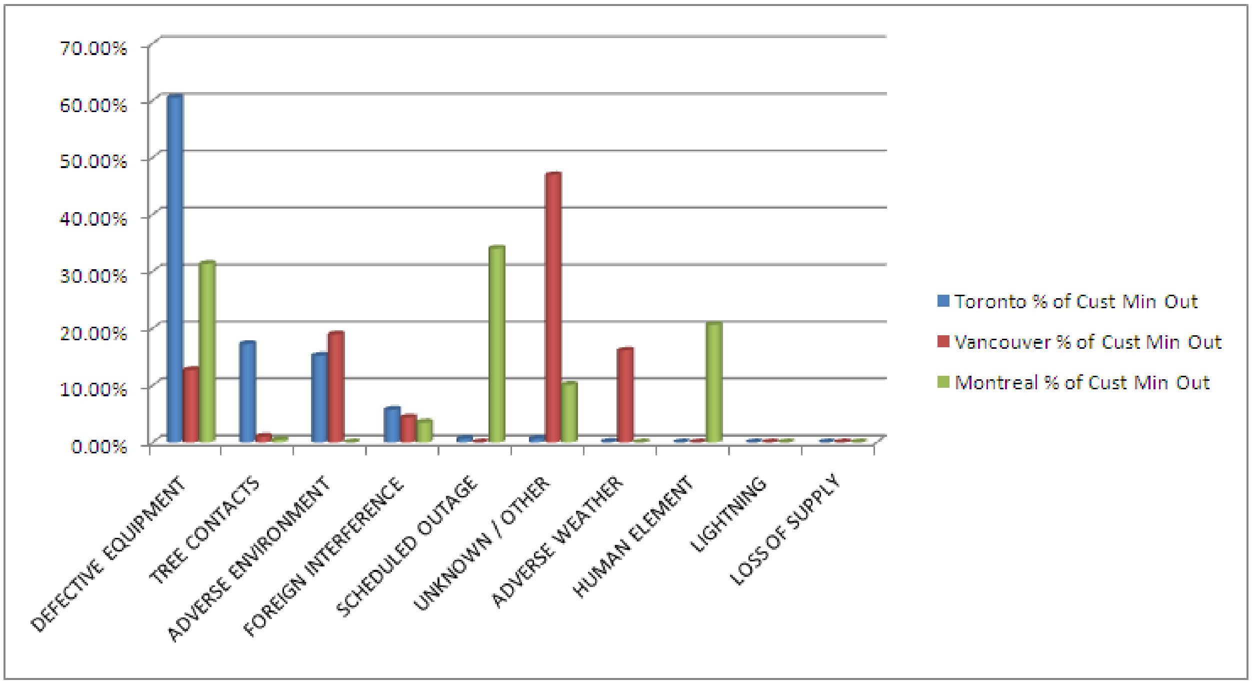

Figure 17: Canadian Cities Downtown Areas - % Customer Minutes Out Comparison

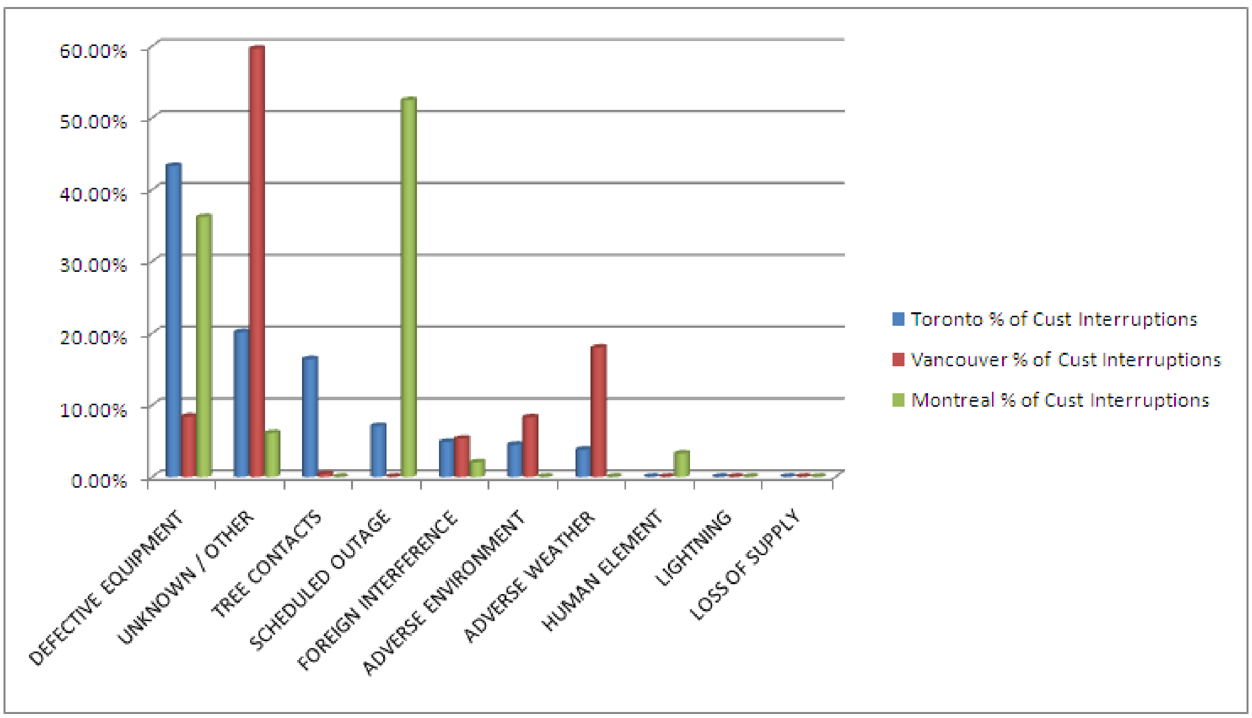

Figure 18: Canadian Cities Downtown Areas - % Customer Interruptions Comparison

Observations:

1. 40% of the customer interruptions in downtown Toronto are caused by defective equipment that translates into 60% of the customer min out. That is higher than metro Toronto.
2. Defective equipment is still a large percentage of the interruptions in downtown Montreal and Vancouver – 31.30% and 12.69% respectively.
3. Tree contacts are still an issue in downtown Toronto, but in downtown Montreal and Vancouver, tree contacts issues disappear. This is due to the fact that both Vancouver and Montreal have almost no overhead in their downtown areas.

9.1.3. Vancouver/Montreal/Toronto SAIDI and SAIFI – Metro and Downtown Comparison

This analysis looks at the SAIDI and SAIFI for Toronto, Montreal and Vancouver, and compares the Metro area to downtown. The results are in Table 17.

City	SAIDI (Min)		SAIFI	
	Metro	Downtown	Metro	Downtown
Toronto	74.53	54.41	1.79	0.81
Montreal	147.14	124.48	2.44	1.29
Vancouver	102.6	120.6	0.54	0.5

Table 17: Vancouver / Montreal / Toronto SAIDI and SAIFI - Metro and Downtown Comparison

Looking at the table it is interesting to note that downtown Vancouver SAIDI is worse than metro Vancouver, but downtown has fewer interruptions. This means that the outages in downtown Vancouver are longer.

Toronto and Montreal show large improvements in SAIDI and SAIFI in downtown compare to the metro area.

9.1.4. Toronto Metro/Downtown – Reliability Data Comparison

To complete the analysis, we compared the reliability data at the interruption causes level for Toronto metro area and Toronto downtown area. We plotted the % customer minutes out and % customer interruptions as shown on the following two graphs.

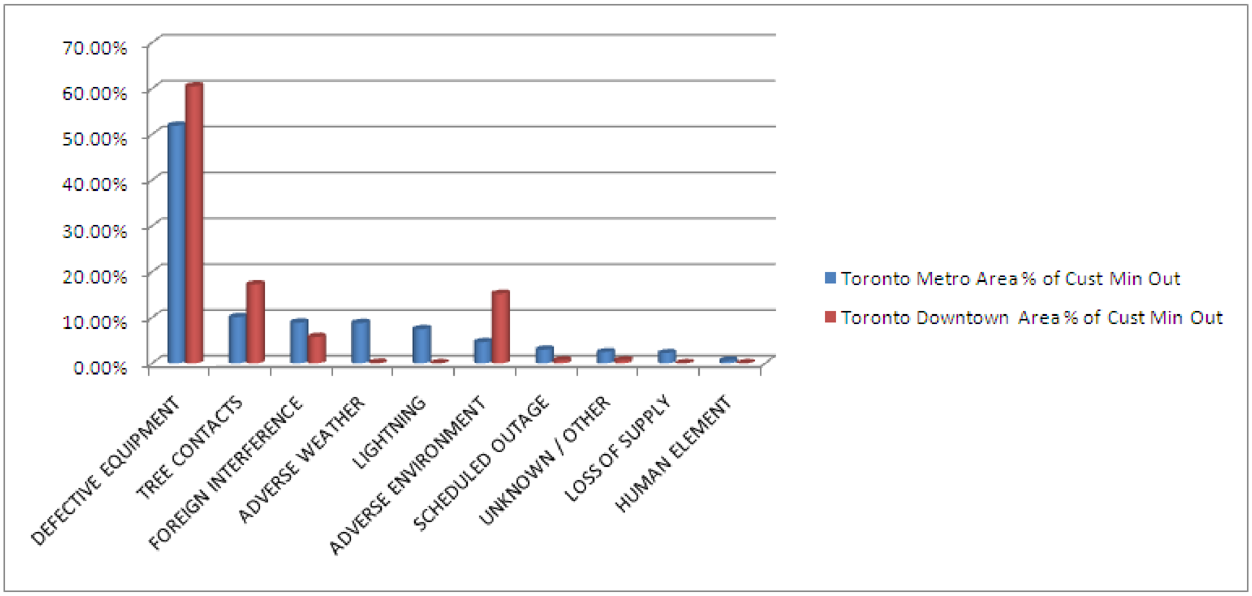

Figure 19: Toronto Metro/Downtown Areas - % Customer Minute Out Comparison

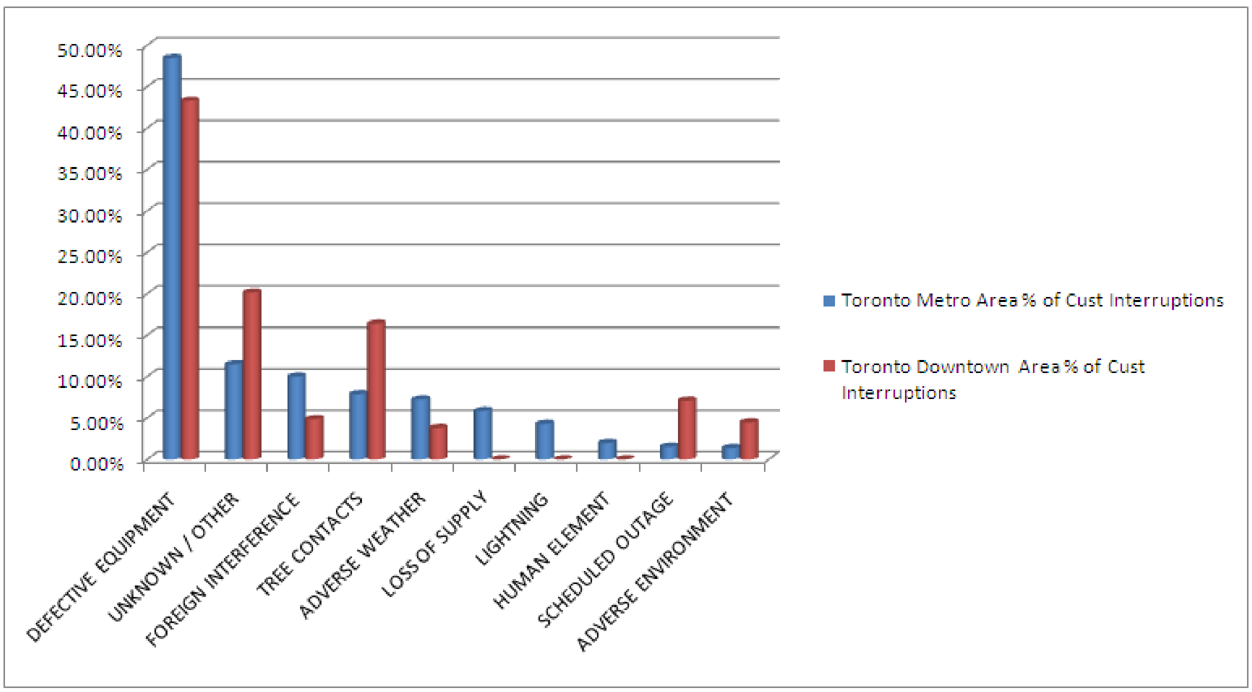

Figure 20: Toronto Metro/Downtown Areas - % Customer Interruptions Comparison

Observations:

1. Defective equipment is a bigger problem in downtown Toronto than in metro Toronto – customer minute out is 10% higher in downtown, but the outages are less frequent.
2. Tree contacts are a bigger issue in downtown Toronto, also the frequency of outages as a result of trees are higher.

3. In downtown Toronto adverse environment is responsible for about 12% of the customer minute out.
4. We could not conclude any specific reasons, but the overall SAIDI and SAIFI is better in downtown Toronto

	SAIDI (Min)	SAIFI
Metro Toronto	74.53	1.79
Downtown Toronto	54.41	0.80

Table 18: Toronto Metro/Downtown SAIDI and SAIFI

9.2. Appendix B: Supporting Documents / Files

9.2.1. Peer Group Cities Criteria

9.2.2. Potential Peer Group Cities

9.2.3. Toronto Hydro Reliability Data

9.2.4. Toronto Hydro Reliability Data Analysis

9.2.5. Other Cities Reliability Data

9.2.6. Data Analysis

9.2.7. Toronto Reliability Plan

9.2.8. Circuits Schematics

9.2.9. Transformation Map

10. Terms and Acronyms

Term	Explanation
C&I	Commercial and Industrial
CAIDI	Customer Average Interruption Duration Index. CAIDI gives the average outage duration that any given customer would experience
CEA	Canadian Electricity Association
CEATI	Centre for Energy Advancement through Technological Innovation (CEATI). CEATI is a user-driven technology solutions exchange, and a development program for utilities. The CEATI program model is built to combine inter-utility information exchange and informal benchmarking with the development of practical projects yielding results that have an immediate impact for our participants
EPRI	Electric Power Research Institute - an independent, non-profit organization, EPRI brings together its scientists and engineers as well as experts from academia and industry to help address challenges in electricity, including reliability, efficiency, health, safety and the environment.
FESI	Feeder Experienced Sustained Interruptions
IEEE	Institute of Electrical and Electronics Engineers - A non-profit organization, IEEE is the world's leading professional association for the advancement of technology.
IOU	Investment Own Utility
IESO	Independent Electricity System Operator
LOLE	Loss of Load Expectation
PHEV	Plug-in hybrid Electric Vehicle
SAIDI	System Average Interruption Duration Index. SAIDI is the average outage duration for each customer served
SAIFI	System Average Interruption Frequency Index. SAIFI is the average number of interruptions that a customer would experience
SCADA	Supervisory Control And Data Acquisition. Generally refers to an industrial control system: a computer system monitoring and controlling a process

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

Toronto Hydro-Electric System Limited
EB-2010-0142
Exhibit R1
Tab 6
Schedule 35
Appendix B
Filed: 2010 Dec 6
(102 pages)

2009 Yearbook of Electricity Distributors

Ontario Energy Board

Published on August 25, 2010

Background on 2009 Yearbook of Electricity Distributors

The Ontario Energy Board is the regulator of Ontario's natural gas and electricity industries. In the electricity sector, the Board sets transmission and distribution rates, and approves the Independent Electricity System Operator's (IESO) and Ontario Power Authority's (OPA) budgets and fees. The Board also sets the rate for the Standard Supply Service for distribution utilities that supply electricity (commodity) directly to consumers.

The Board provides this 2009 Yearbook of Electricity Distributors to inform interested parties and the general public with financial and operational information collected from Electricity Distributors. It is compiled from data submitted by the Distributors through the Reporting and Record-Keeping Requirements. Hydro One Remote Communities and direct connections to the transmission grid are not presented.

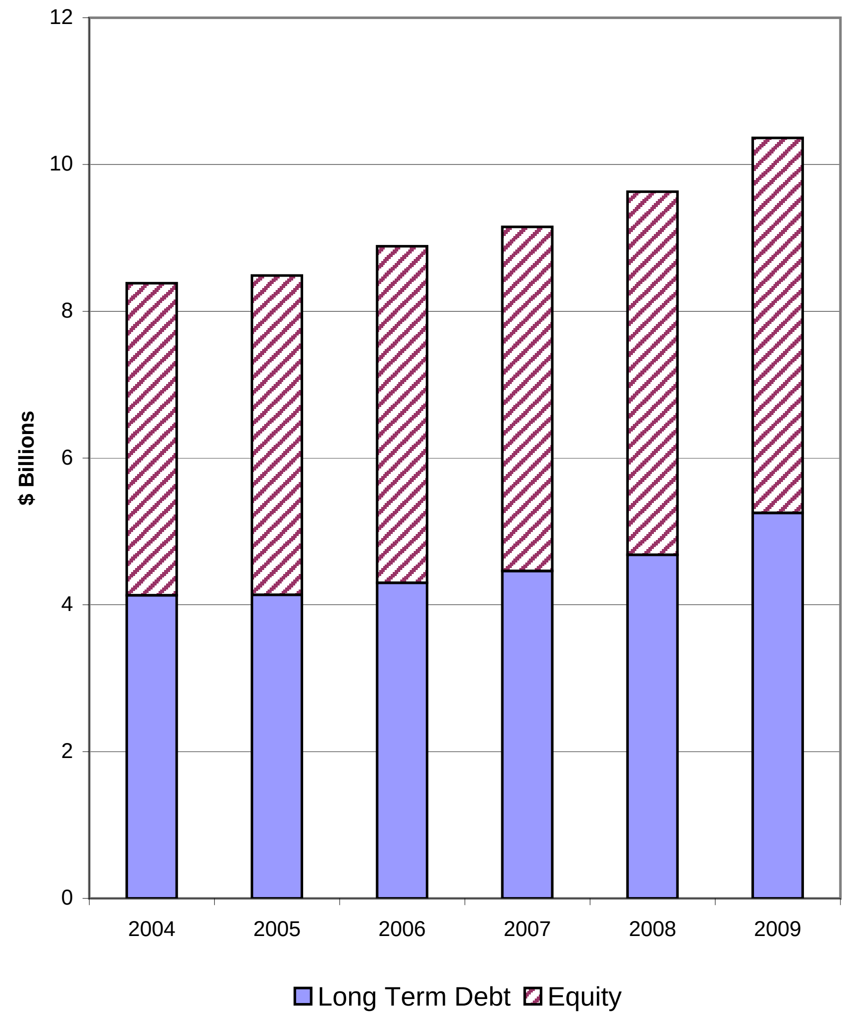
Table of Contents

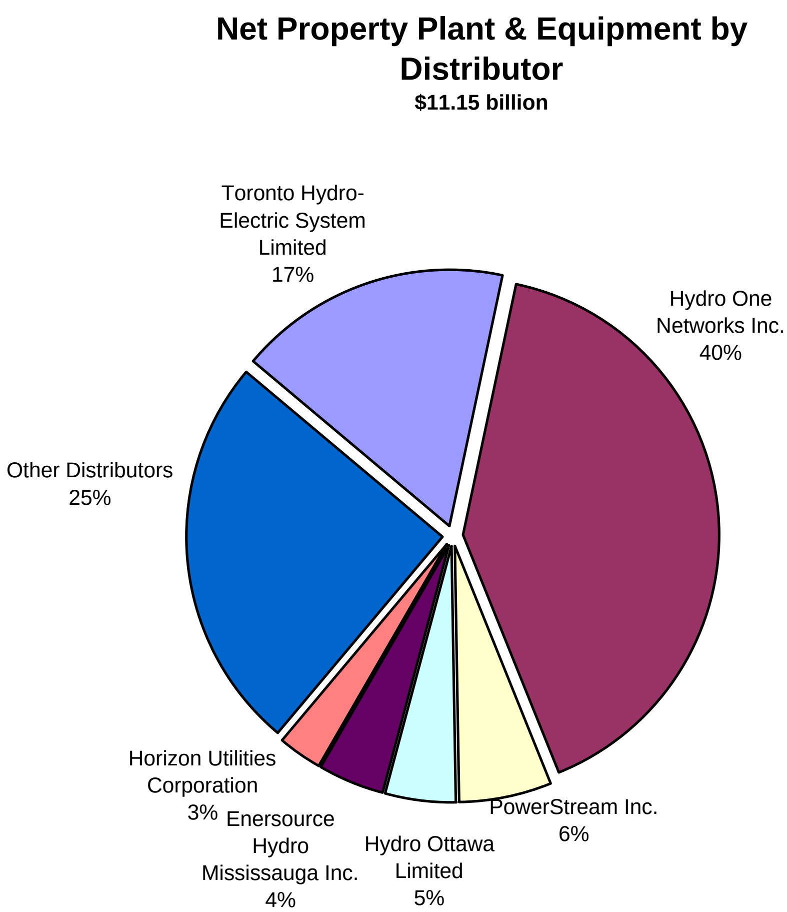
*The following distributors have not filed RRR information for 2009: Attawapiskat First Nation, Fort Albany First Nation and Kashechewan First Nation.

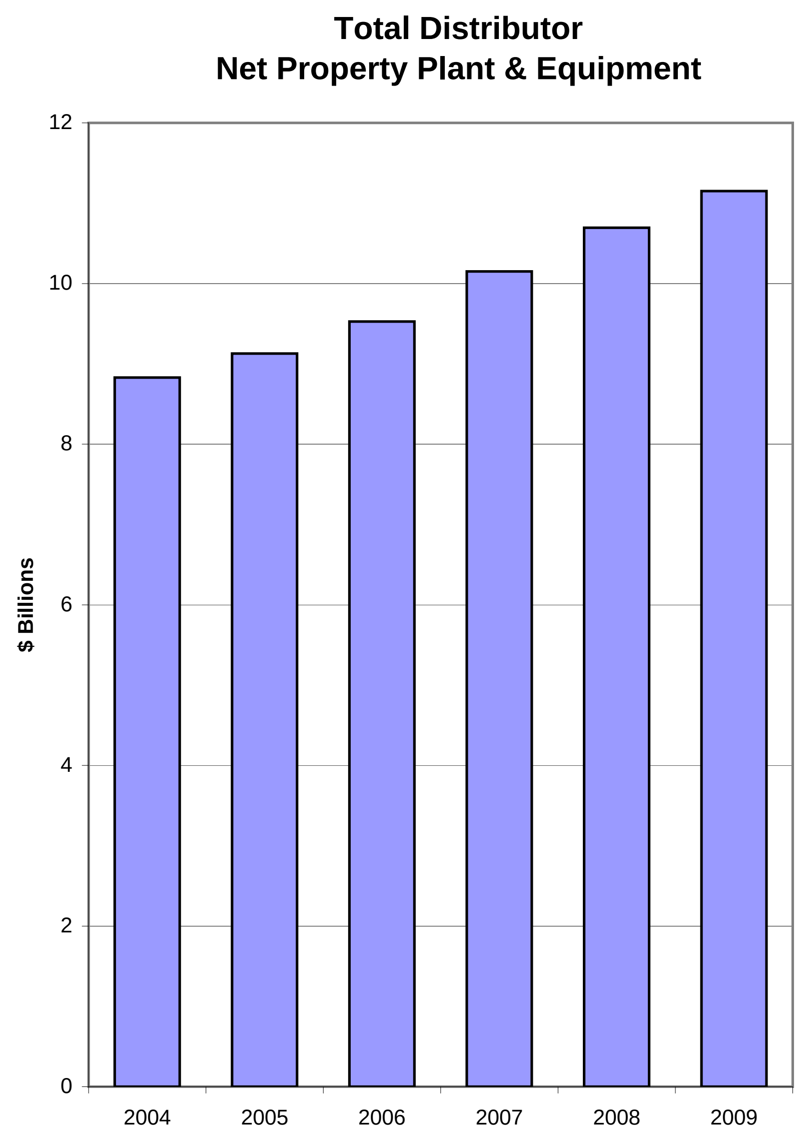
Overview of Ontario Electricity Distributors

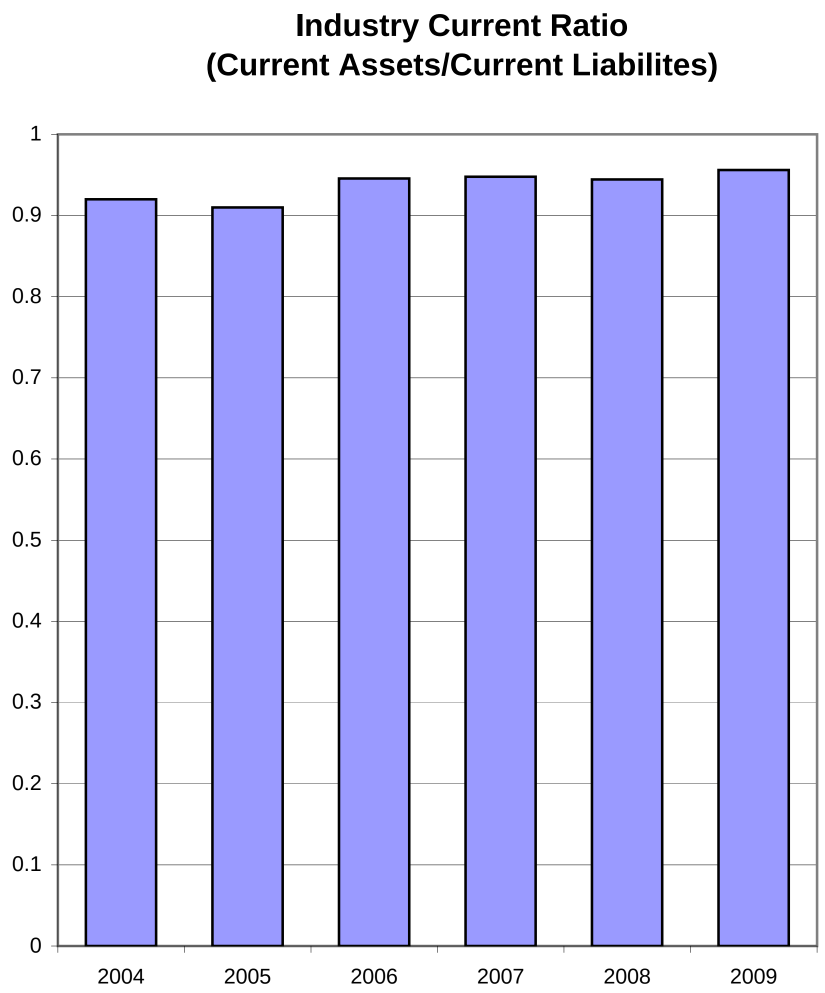
Balance Sheet	As of December 31, 2009 $ thousands
Cash & cash equivalents	363,375
Receivables	3,944,740
Inventory	88,573
Inter-company	25,901
Other current assets	39,695
Current assets	4,462,284
Property plant & equipment	20,216,463
Accumulated depreciation & amortization	(9,066,171)
	11,150,293
Regulatory assets (net)	497,359
Inter-company	1,393
Other non-current assets	337,923
Total Assets	16,449,251
Accounts payable & accrued charges	1,798,239
Current Portion of Future Income Taxes	(7,735)
Other current liabilities	65,232
Inter-company	2,483,527
Loans, notes payable, current portion long term debt	328,460
Current liabilities	4,667,724
Long-term debt	1,786,001
Inter-company debt and advances	3,467,351
Regulatory liabilities	86,297
Other deferred amounts and customer deposits	382,532
Employeee future benefits	857,703
Future income taxes	86,840
Total Liabilities	11,334,448
Shareholders' Equity	5,114,803
Total Liabilities & Equity	21,116,975

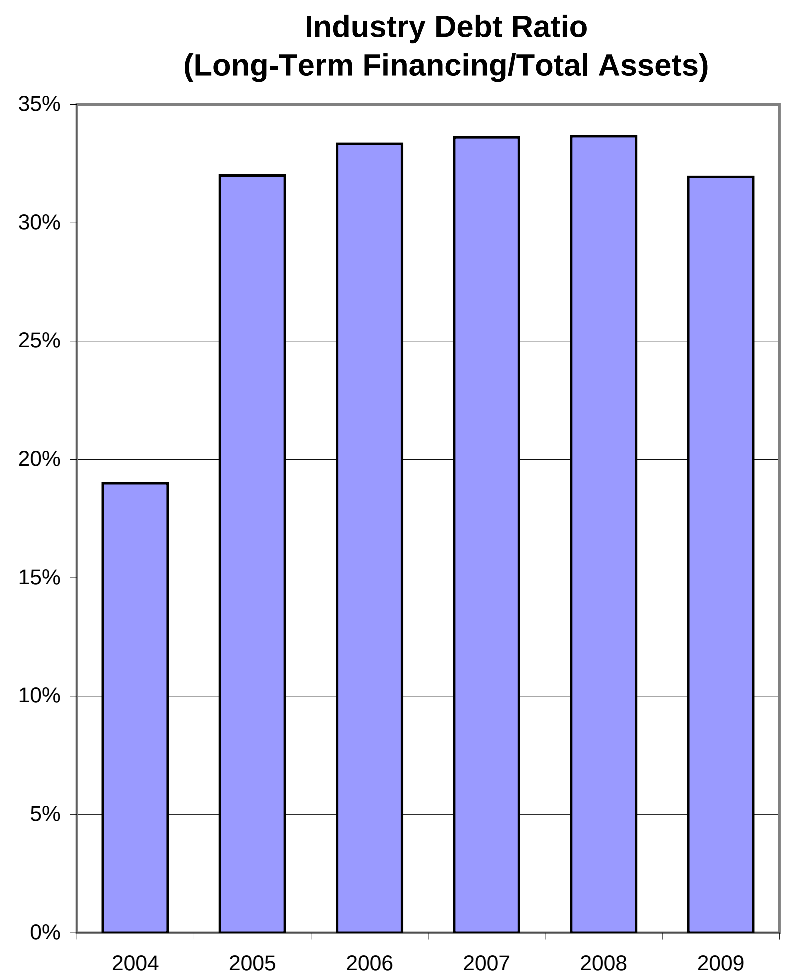
Long-Term Financing & Equity of Distributors

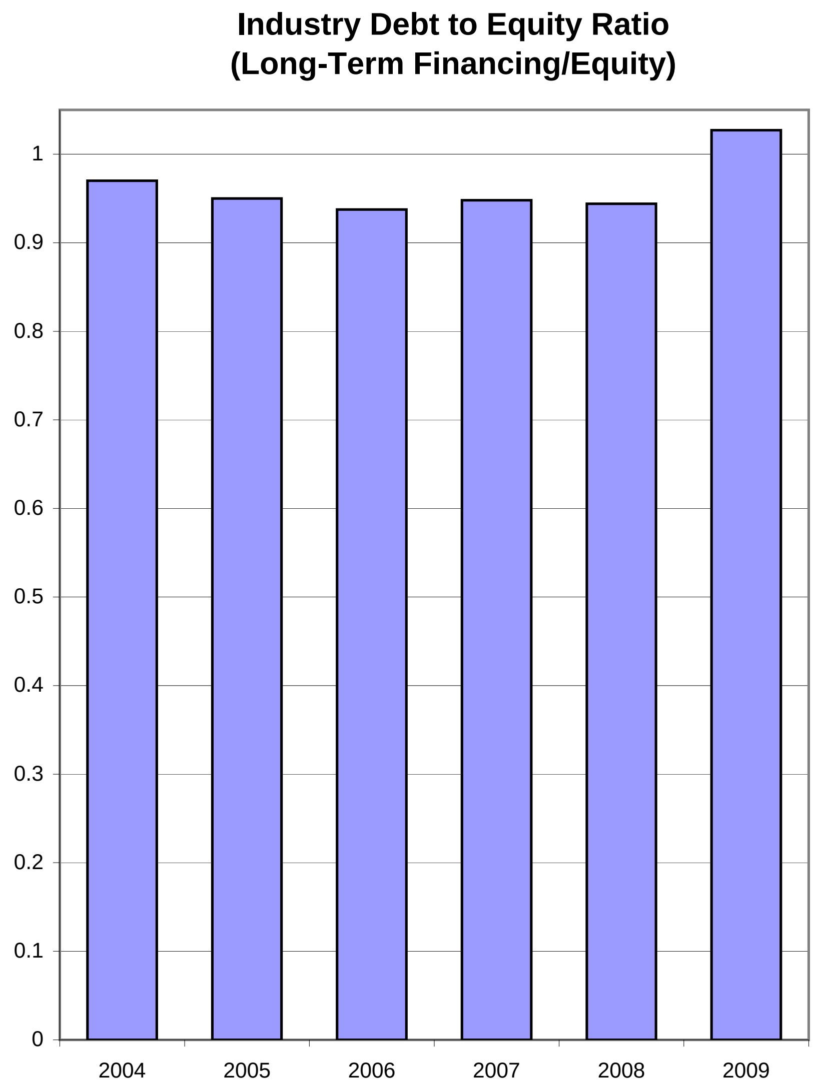


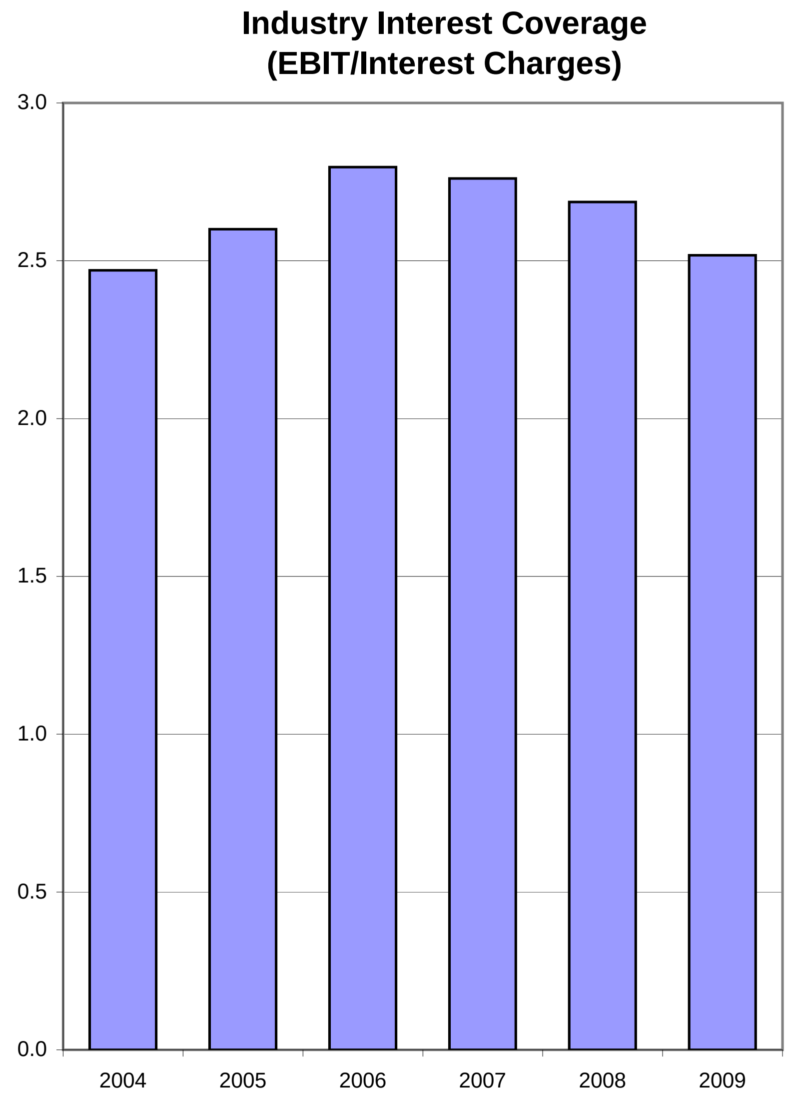

Net Property Plant & Equipment by Distributor
$11.15 billion
Toronto Hydro-Electric System Limited 17%
Hydro One Networks Inc. 40%
Other Distributors 25%
Horizon Utilities Corporation 3%
Enersource Hydro Mississauga Inc. 4%
Hydro Ottawa Limited 5%
PowerStream Inc. 6%


Total Distributor
Net Property Plant & Equipment
$ Billions
0
2
4
6
8
10
12
2004
2005
2006
2007
2008
2009


Industry Current Ratio
(Current Assets/Current Liabilites)
1
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0.2
0.1
0
2004
2005
2006
2007
2008
2009

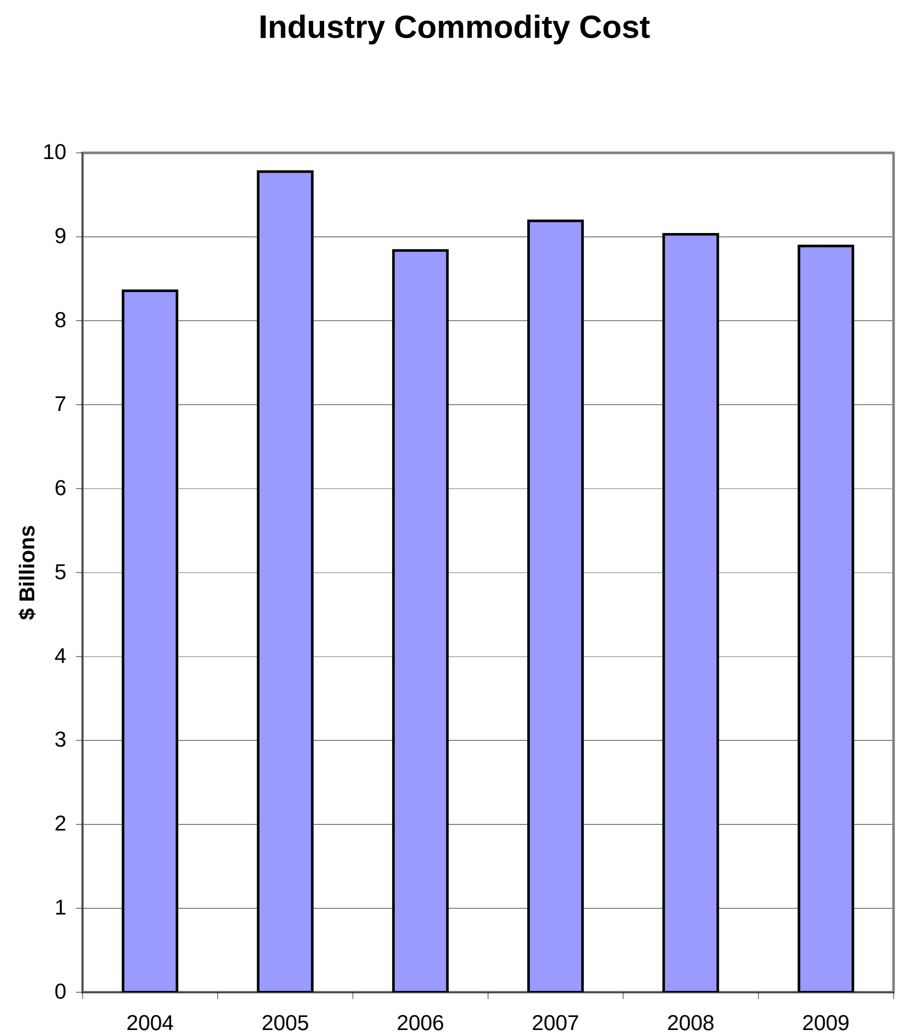

Industry Debt Ratio
(Long-Term Financing/Total Assets)
35%
30%
25%
20%
15%
10%
5%
0%
2004
2005
2006
2007
2008
2009

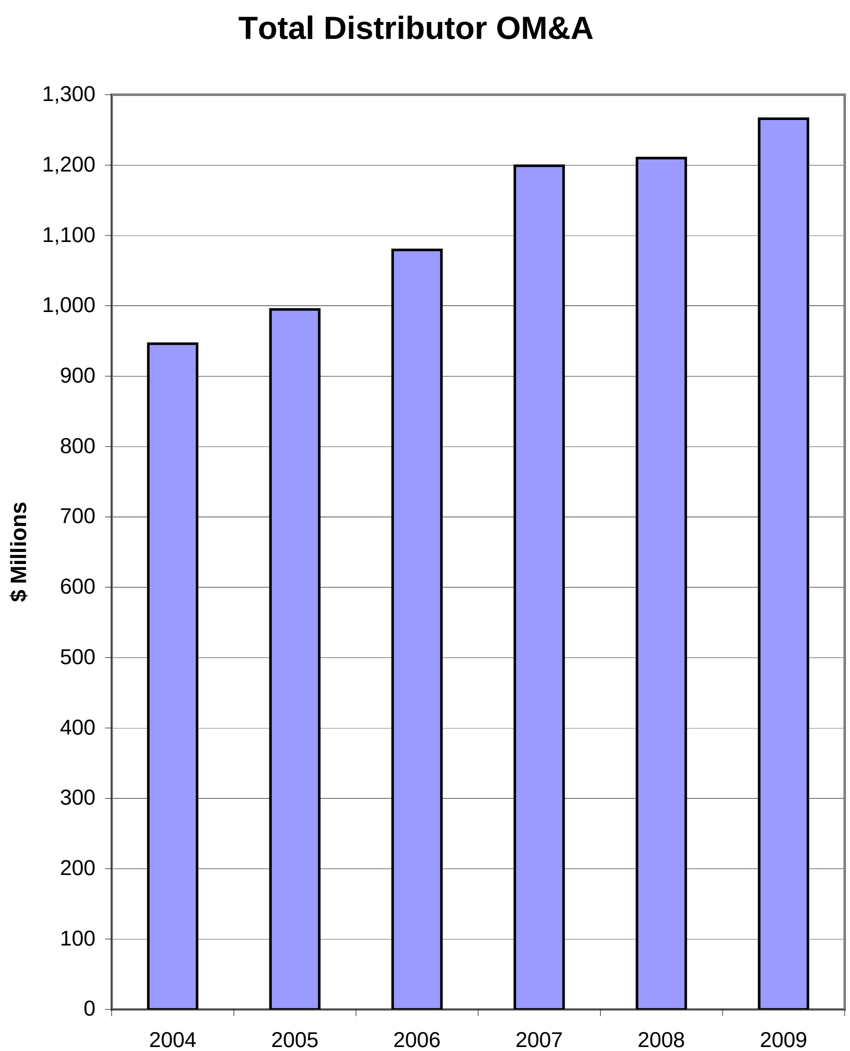

Industry Debt to Equity Ratio
(Long-Term Financing/Equity)
1
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0.2
0.1
0
2004
2005
2006
2007
2008
2009

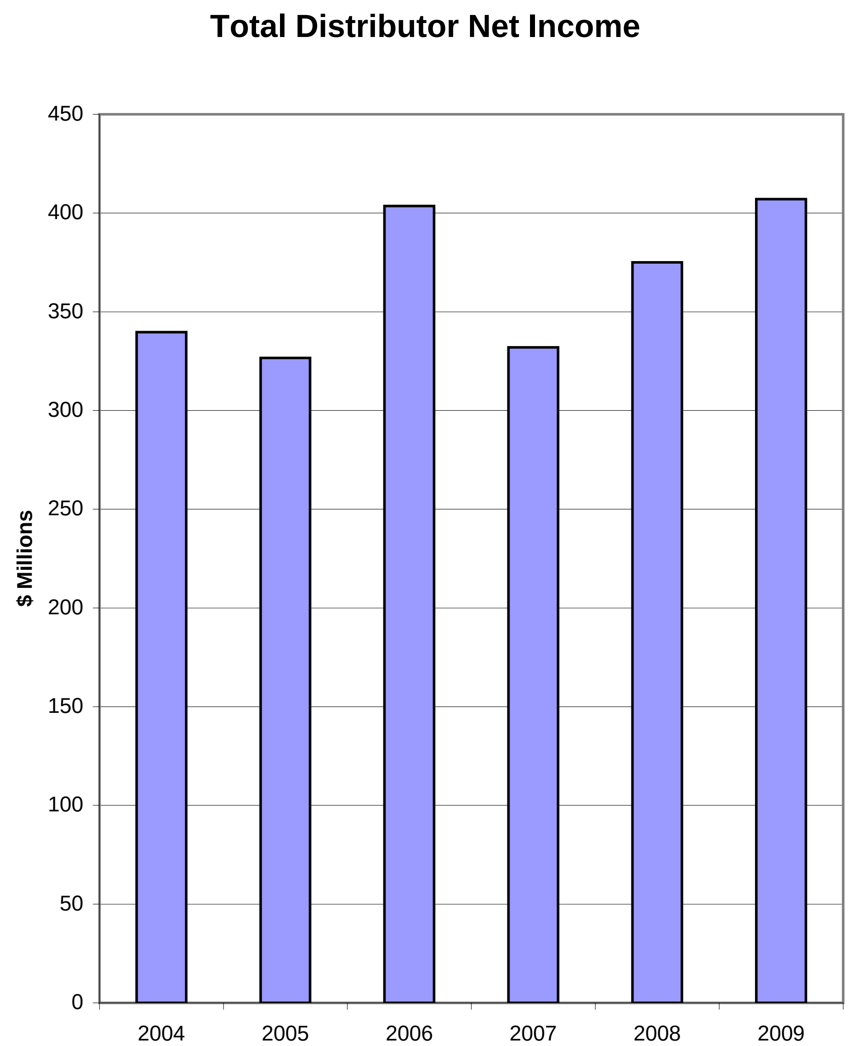

Industry Interest Coverage
(EBIT/Interest Charges)
3.0
2.5
2.0
1.5
1.0
0.5
0.0
2004
2005
2006
2007
2008
2009

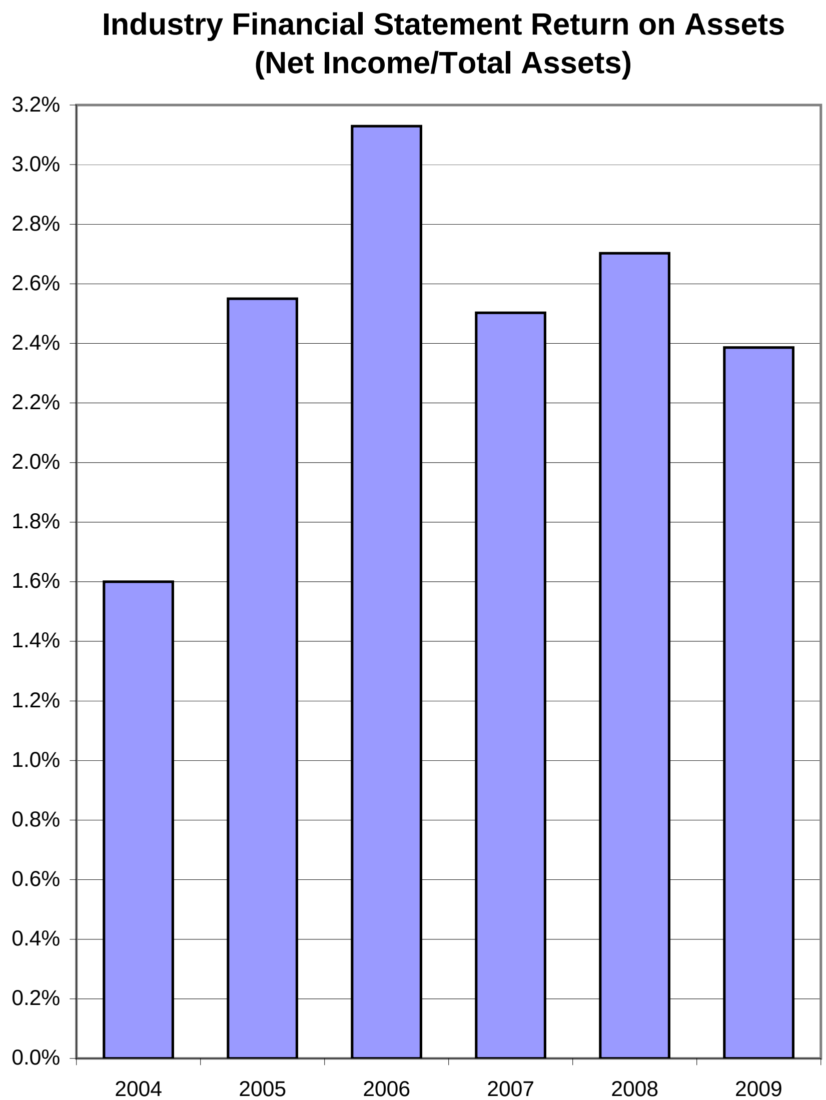
Overview of Ontario Electricity Distributors

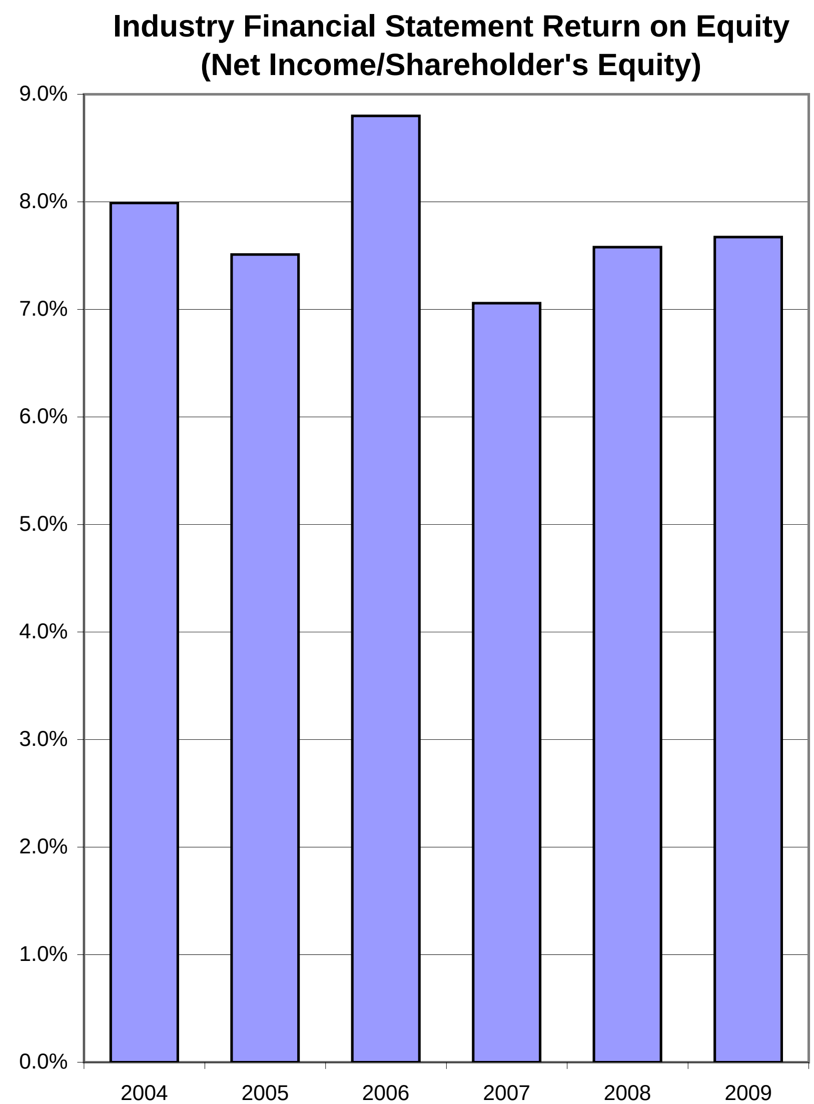
Income Statement	Year ended December 31, 2009 $ thousands
Revenue	
Power & Distribution Revenue	11,840,238
Cost of Power & Related Costs	8,963,586
	2,876,652
Other Income	102,250
Expenses	
Operation	263,337
Maintenance	368,019
Administration	635,577
Other	61,541
Depreciation and Amortization	765,251
Financing	351,648
	2,445,374
PILS and Income Taxes	
Current	142,638
Future	(1,562)
	141,076
Net Income	392,452




Total Distributor OM&A
$ Millions
1,300
1,200
1,100
1,000
900
800
700
600
500
400
300
200
100
0
2004
2005
2006
2007
2008
2009


Total Distributor Net Income
$ Millions
450
400
350
300
250
200
150
100
50
0
2004
2005
2006
2007
2008
2009


Industry Financial Statement Return on Assets
(Net Income/Total Assets)
3.2%
3.0%
2.8%
2.6%
2.4%
2.2%
2.0%
1.8%
1.6%
1.4%
1.2%
1.0%
0.8%
0.6%
0.4%
0.2%
0.0%
2004
2005
2006
2007
2008
2009


Industry Financial Statement Return on Equity
(Net Income/Shareholder's Equity)
9.0%
8.0%
7.0%
6.0%
5.0%
4.0%
3.0%
2.0%
1.0%
0.0%
2004
2005
2006
2007
2008
2009

Overview of Ontario Electricity Distributors

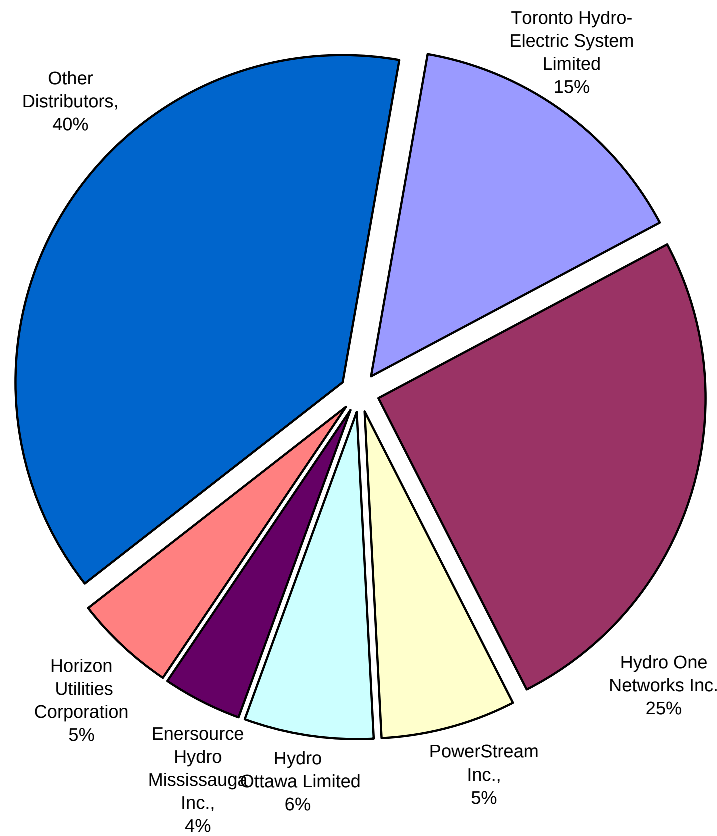
GENERAL STATISTICS

		Year ended December 31, 2009
Population Served		13,346,146
Municipal		14,037,325
Seasonal		163,857
Total Customers		4,748,577
Residential Customers		4,260,374
General Service <50kW Customers		422,274
General Service >50kW Customers		48,799
Large User (>5000kW) Customers		136
Scattered Unmetered Loads		16,618
Sub Transmission		376
Total Service Area (sq km)		681,489
% Urban		1%
% Rural		99%
Total km of Line		196,815
Overhead km of line		158,888
Underground km of line		37,927
Total kWh sold (excluding losses)		118,959,458,726
Total Distribution Losses (kWh)		5,246,573,177
Total kWh Purchased		124,206,031,903
Capital Additions in 2009	$	1,457,372,544

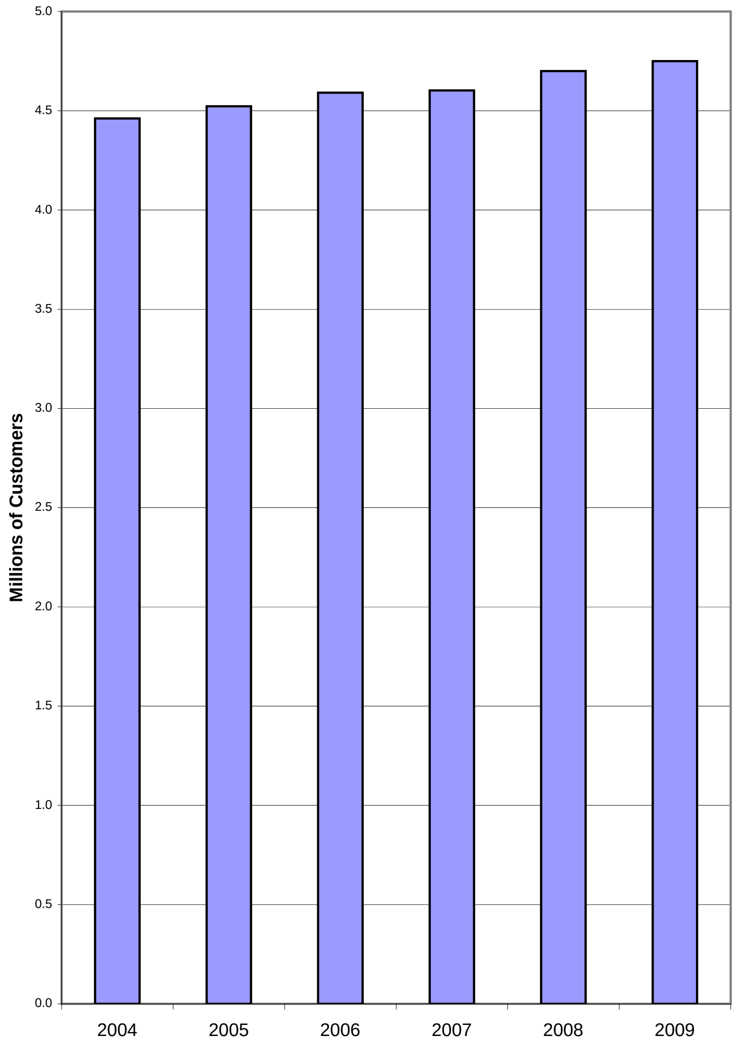
UNITIZED STATISTICS

# of Customers per sq km of Service Area		6.97
# of Customers per km of Line		24.13
Average Revenue from Distribution		
Per Customer annually	$	605.79
Per Total kWh Purchased	$	0.023
Annual Average Cost of Power:		
Per Customer	$	1,888
Per total kWh Purchased	$	0.0722
Average monthly total kWh consumed per customer		2,180
OM&A per customer	$	267
Net Income per customer	$	83
Net Fixed Assets per customer	$	2,348

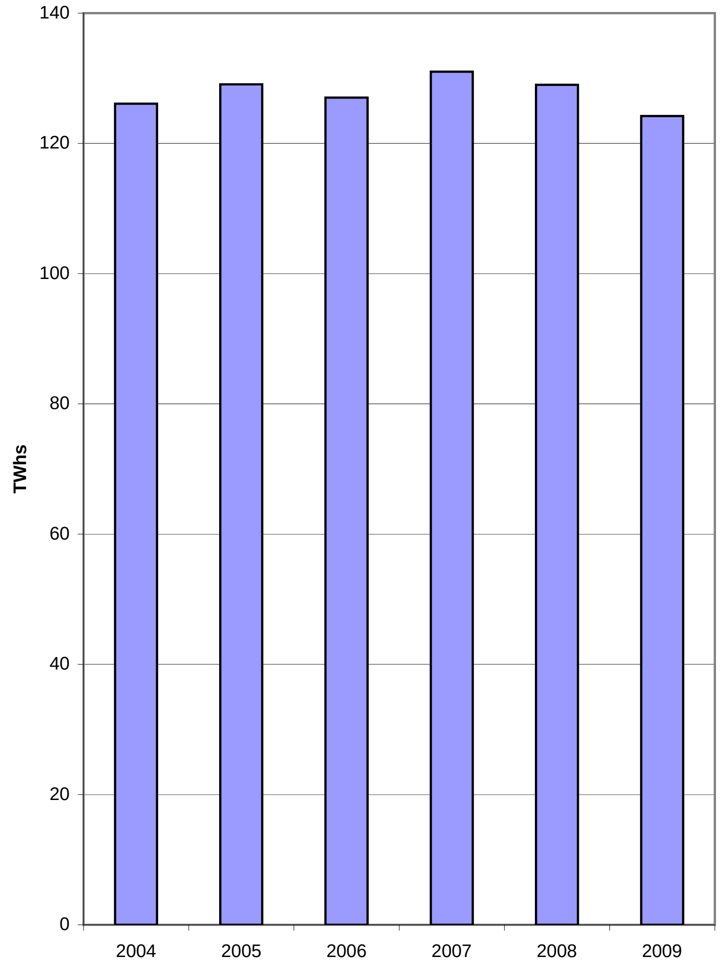
Percentage of Distribution Customers



Total Number of Customers of Distributors



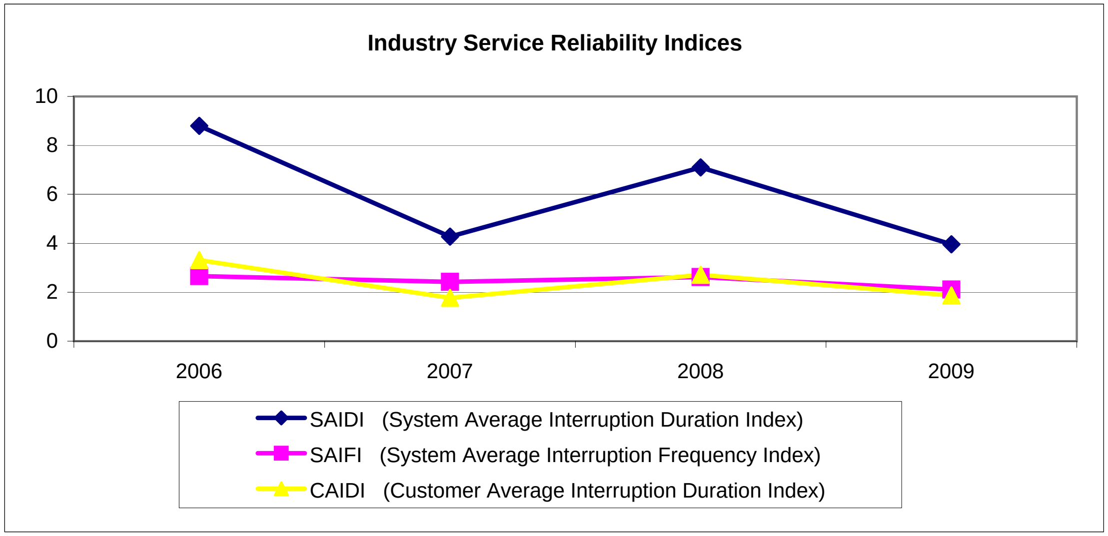
Total TWhs Purchased from IESO



Service Reliability Indices

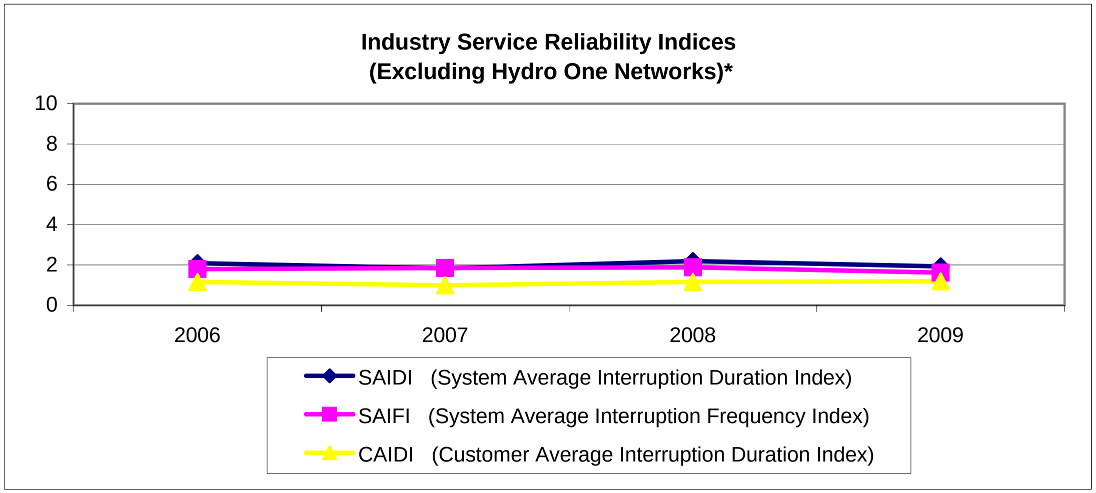
Industry

	2006	2007	2008	2009
SAIDI	8.8	4.27	7.1	3.96
SAIFI	2.66	2.42	2.62	2.11
CAIDI	3.31	1.77	2.71	1.87



Industry Excluding Hydro One Networks

	2006	2007	2008	2009
SAIDI	2.09	1.83	2.19	1.93
SAIFI	1.79	1.85	1.88	1.62
CAIDI	1.16	0.99	1.16	1.19



*Hydro One Networks has a major impact on the industry statistics due to low customer density, service areas spread across the province and occurrence of significant weather related outages in 2006 and 2009.

Note: Outage statistics report all outages affecting customers including those arising from within the distributor service area and those arising upstream from the distributor.

Balance Sheet As of December 31, 2009 (Alphabetically Listed)	Algoma Power Inc.	Atikokan Hydro Inc.	Bluewater Power Distribution Corporation	Brant County Power Inc.	Brantford Power Inc.	Burlington Hydro Inc.
Cash & cash equivalents	973,079	46,801	7,872,876	2,344,724	7,722,700	9,199,544
Receivables	4,845,053	652,902	18,050,974	5,083,160	16,766,758	34,600,441
Inventory	1,269,336	102,578	613,182	234,314	1,769,206	1,179,152
Inter-company	5,438,105	-	381,547	-	-	4,300
Other current assets	64,536	349,296	248,175	127,140	271,122	1,681,963
Current assets	12,590,109	1,151,577	27,166,754	7,789,338	26,529,786	46,665,400
Property plant & equipment	107,439,737	4,812,714	95,587,404	27,500,541	83,256,840	198,937,356
Accumulated depreciation & amortization	(44,498,124)	(2,756,093)	(56,767,920)	(8,345,415)	(23,274,722)	(114,390,672)
	62,941,614	2,056,621	38,819,484	19,155,126	59,982,117	84,546,684
Regulatory assets (net)	5,223,464	456,064	(1,452,720)	(982,105)	(6,941,272)	2,941,728
Inter-company	-	-	-	582,850	-	-
Other non-current assets	-	-	-	-	1,969,598	31,555
Total Assets	$ 80,755,187	$ 3,664,262	$ 64,533,518	$ 26,545,209	$ 81,540,228	$ 134,185,367
Accounts payable & accrued charges	$ 3,482,035	$ 470,991	$ 13,765,391	$ 4,596,927	$ 9,687,905	$ 26,080,958
Current Portion of Future Income Taxes	(3,190,610)	(83,742)	-	(491,661)	(176,390)	-
Other current liabilities	531,380	(30,861)	65,898	90,683	18,601	48,353
Inter-company	928,936	-	1,874,957	12,288	1,681,762	47,853
Loans and notes payable, and current portion of long term debt	-	13,001	47,798	-	2,011,369	-
Current liabilities	1,751,741	369,389	15,754,044	4,208,237	13,223,247	26,177,163
Long-term debt	-	2,101,828	19,377,604	5,000,000	12,121,619	47,878,608
Inter-company debt & advances	45,600,000	-	-	-	24,189,168	-
Regulatory liabilities	(416,485)	-	-	10,332	-	13,316
Other deferred amounts & customer deposits	366,171	97,529	1,785,865	179,886	2,042,206	5,599,915
Employeee future benefits	883,496	-	6,583,822	646,300	701,757	2,817,042
Future income taxes	-	83,742	-	-	(3,228,631)	(4,880,035)
Total Liabilities	48,184,923	2,652,488	43,501,335	10,044,755	49,049,366	77,606,009
Shareholders' Equity	32,570,263	1,011,774	21,032,183	16,500,454	32,490,862	56,579,358
LIABILITIES & SHAREHOLDERS' EQUITY	$ 80,755,187	$ 3,664,262	$ 64,533,518	$ 26,545,209	$ 81,540,228	$ 134,185,367

Balance Sheet As of December 31, 2009 (Alphabetically Listed)	Cambridge and North Dumfries Hydro Inc.	Canadian Niagara Power Inc.	Centre Wellington Hydro Ltd.	Chapleau Public Utilities Corporation	Chatham-Kent Hydro Inc.	Clinton Power Corporation
Cash & cash equivalents	20,090,374	1,437,212	3,948,252	449,397	4,824,338	450,558
Receivables	21,794,947	7,149,362	3,239,531	600,320	13,576,784	1,043,813
Inventory	1,311,333	102,457	253,265	48,965	631,201	87,473
Inter-company	2,160	-	-	4,694	-	7,284
Other current assets	447,598	145,103	124,128	-	12,240	-
Current assets	43,646,412	8,834,133	7,565,176	1,103,377	19,044,563	1,589,128
Property plant & equipment	168,517,507	82,411,997	15,255,116	2,233,515	75,580,332	1,734,650
Accumulated depreciation & amortization	(84,713,702)	(32,627,360)	(8,541,456)	(1,386,047)	(29,005,219)	(482,033)
	83,803,805	49,784,637	6,713,660	847,468	46,575,113	1,252,617
Regulatory assets (net)	(5,960,911)	2,965,696	(734,356)	97,964	3,596,405	224,595
Inter-company	-	-	-	-	-	-
Other non-current assets	11,678,102	3,698,442	20,237	-	-	-
Total Assets	$ 133,167,408	$ 65,282,908	$ 13,564,718	$ 2,048,809	$ 69,216,080	$ 3,066,339
Accounts payable & accrued charges	$ 20,004,624	$ 7,021,697	$ 1,994,598	$ 372,102	$ 9,680,817	$ 2,475,372
Current Portion of Future Income Taxes	-	365,324	-	-	-	-
Other current liabilities	386,528	(4,810)	47,928	(4,633)	180,974	(59,764)
Inter-company	73,630	1,484,163	-	-	2,843,576	-
Loans and notes payable, and current portion of long term debt	-	-	94,043	-	-	-
Current liabilities	20,464,782	8,866,374	2,136,570	367,469	12,705,367	2,415,608
Long-term debt	35,000,000	16,050,000	5,046,753	-	-	-
Inter-company debt & advances	6,684,703	20,000,000	-	-	23,523,326	-
Regulatory liabilities	-	-	-	15,246	-	(38,078)
Other deferred amounts & customer deposits	6,299,149	-	1,055,359	23,019	2,761,918	55,426
Employeee future benefits	1,716,708	3,901,218	106,544	-	917,524	-
Future income taxes	-	1,462,699	(1,020,035)	-	-	-
Total Liabilities	70,165,342	50,280,292	7,325,191	405,734	39,908,135	2,432,956
Shareholders' Equity	63,002,066	15,002,616	6,239,526	1,643,075	29,307,945	633,383
LIABILITIES & SHAREHOLDERS' EQUITY	$ 133,167,408	$ 65,282,908	$ 13,564,718	$ 2,048,809	$ 69,216,080	$ 3,066,339

Balance Sheet As of December 31, 2009 (Alphabetically Listed)	COLLUS Power Corporation	Cooperative Hydro Embrun Inc.	E.L.K. Energy Inc.	Enersource Hydro Mississauga Inc.	EnWin Utilities Ltd.	Erie Thames Powerlines Corporation
Cash & cash equivalents	1,104,101	1,432,403	5,038,655	11,132,626	6,725,115	682,426
Receivables	6,494,373	330,179	4,783,391	112,454,914	18,085,861	7,006,999
Inventory	297,789	-	342,091	7,747,361	2,244,097	66,683
Inter-company	-	-	(362,924)	133,268	-	-
Other current assets	175,009	-	88,793	849,261	771,397	54,256
Current assets	8,071,272	1,762,582	9,890,005	132,317,430	27,826,470	7,810,364
Property plant & equipment	26,074,511	2,999,863	22,432,097	866,506,147	290,485,312	25,189,432
Accumulated depreciation & amortization	(13,535,484)	(1,085,471)	(13,904,674)	(416,914,977)	(110,625,593)	(6,853,983)
	12,539,027	1,914,392	8,527,424	449,591,170	179,859,719	18,335,449
Regulatory assets (net)	(953,925)	162,849	3,259,424	12,237,673	(6,134,987)	2,064,755
Inter-company	-	-	100	-	-	-
Other non-current assets	99,212	136,853	47,062	21,057,560	20,089,168	4,000
Total Assets	$ 19,755,587	$ 3,976,676	$ 21,724,015	$ 615,203,833	$ 221,640,371	$ 28,214,568
Accounts payable & accrued charges	$ 7,519,633	$ 471,055	$ 3,024,275	$ 93,575,134	$ 14,760,452	$ 9,981,435
Current Portion of Future Income Taxes	(178,811)	-	-	(261,861)	-	(297,000)
Other current liabilities	(11,116)	(13,501)	(306,303)	(3,085,483)	1,063,819	308,763
Inter-company	-	-	-	1,308,552	19,795,333	-
Loans and notes payable, and current portion of long term debt	-	-	-	2,922,591	1,219,315	-
Current liabilities	7,329,706	457,554	2,717,972	94,458,933	36,838,919	9,993,198
Long-term debt	1,710,170	2,862,994	9,900,000	290,000,000	50,000,000	8,038,524
Inter-company debt & advances	-	-	-	-	-	485,915
Regulatory liabilities	51,390	-	1,483,000	-	283,865	329,202
Other deferred amounts & customer deposits	-	22,681	728,873	20,807,421	25,223,779	1,031,194
Employeee future benefits	281,085	-	686,513	3,912,323	33,534,140	-
Future income taxes	-	-	-	-	-	-
Total Liabilities	9,372,350	3,343,228	15,516,358	409,178,677	145,880,702	19,878,033
Shareholders' Equity	10,383,237	633,447	6,207,657	206,025,156	75,759,669	8,336,534
LIABILITIES & SHAREHOLDERS' EQUITY	$ 19,755,587	$ 3,976,676	$ 21,724,015	$ 615,203,833	$ 221,640,371	$ 28,214,568

Balance Sheet **As of December 31, 2009** **(Alphabetically Listed)**	Espanola Regional Hydro Distribution Corporation	Essex Powerlines Corporation	Festival Hydro Inc.	Fort Frances Power Corporation	Greater Sudbury Hydro Inc.	Grimsby Power Incorporated
Cash & cash equivalents	1,017,112	10,240,908	1,720,507	1,975,381	10,634,296	1,142,964
Receivables	1,401,745	11,145,384	9,070,507	1,728,119	20,741,406	2,502,401
Inventory	140,225	60,000	243,804	134,758	1,211,260	181,885
Inter-company	-	-	-	-	-	5,595
Other current assets	34,136	23,046	1,007,354	21,502	719,491	33,207
Current assets	2,593,218	21,469,338	12,042,172	3,859,759	33,306,453	3,866,053
Property plant & equipment	6,512,951	46,092,589	73,954,187	10,110,278	162,640,073	23,814,394
Accumulated depreciation & amortization	(4,456,311)	(14,124,639)	(41,243,269)	(7,200,757)	(98,197,098)	(12,409,113)
	2,056,640	31,967,950	32,710,918	2,909,521	64,442,975	11,405,281
Regulatory assets (net)	638,891	2,094,134	(4,413,529)	120,917	(2,849,959)	(2,006,211)
Inter-company	-	-	-	-	400,000	94,500
Other non-current assets	-	-	33,184	-	-	-
Total Assets	$ 5,288,748	$ 55,531,422	$ 40,372,745	$ 6,890,197	$ 95,299,469	$ 13,359,623
Accounts payable & accrued charges	$ 1,911,034	$ 9,695,043	$ 6,931,060	$ 1,093,401	$ 16,544,207	$ 1,895,635
Current Portion of Future Income Taxes	-	-	-	-	(1,543,669)	-
Other current liabilities	41,981	(34,530)	195,182	74,874	40,302	36,331
Inter-company	-	-	15,537,919	-	50,371,589	31,410
Loans and notes payable, and current portion of long term debt	88,727	2,950,600	-	-	403,179	420,449
Current liabilities	2,041,742	12,611,113	22,664,161	1,168,276	65,815,608	2,383,826
Long-term debt	-	19,710,999	-	-	-	5,782,746
Inter-company debt & advances	1,524,511	-	-	-	-	-
Regulatory liabilities	27,860	-	(33,449)	7,000	735,990	-
Other deferred amounts & customer deposits	57,400	616,936	599,030	118,574	1,401,559	421,752
Employeee future benefits	-	4,464,592	1,234,998	-	18,212,494	-
Future income taxes	-	-	(2,585,975)	-	(6,335,809)	(1,119,859)
Total Liabilities	3,651,512	37,403,639	21,878,765	1,293,850	79,829,842	7,468,464
Shareholders' Equity	1,637,236	18,127,783	18,493,980	5,596,348	15,469,627	5,891,159
LIABILITIES & SHAREHOLDERS' EQUITY	$ 5,288,748	$ 55,531,422	$ 40,372,745	$ 6,890,197	$ 95,299,469	$ 13,359,623

Balance Sheet As of December 31, 2009 (Alphabetically Listed)	Guelph Hydro Electric Systems Inc.	Haldimand County Hydro Inc.	Halton Hills Hydro Inc.	Hearst Power Distribution Company Limited	Horizon Utilities Corporation	Hydro 2000 Inc.
Cash & cash equivalents	4,863,054	7,513,910	(330,046)	3,785,308	(23,613,347)	314,786
Receivables	16,530,706	5,537,268	10,295,214	1,304,866	88,348,521	227,017
Inventory	1,441,589	843,516	543,797	117,358	6,340,625	-
Inter-company	110,212	(493,034)	1,775,729	-	14,494,225	-
Other current assets	798,516	101,420	238,883	9,431	1,601,397	39,985
Current assets	23,744,076	13,503,079	12,523,577	5,216,963	87,171,421	581,787
Property plant & equipment	140,337,484	54,531,594	46,102,472	3,828,988	634,890,680	813,110
Accumulated depreciation & amortization	(49,741,295)	(20,204,612)	(16,360,967)	(2,965,513)	(312,468,400)	(374,064)
	90,596,189	34,326,981	29,741,505	863,475	322,422,280	439,046
Regulatory assets (net)	(3,230,456)	3,046,235	6,021,400	(400,106)	(2,021,419)	231,522
Inter-company	-	-	-	-	-	-
Other non-current assets	66,109	-	-	-	-	-
Total Assets	$ 111,175,919	$ 50,876,296	$ 48,286,482	$ 5,680,333	$ 407,572,282	$ 1,252,355
Accounts payable & accrued charges	$ 11,153,200	$ 8,578,853	$ 8,010,092	$ 1,163,061	$ 73,639,450	$ 276,855
Current Portion of Future Income Taxes	(636,240)	(840,300)	-	-	-	6,686
Other current liabilities	448,854	155,544	72,603	(18,962)	790,340	8,107
Inter-company	13,455,673	-	-	-	151,000,662	-
Loans and notes payable, and current portion of long term debt	2,727	8,069,998	1,500,000	-	-	-
Current liabilities	24,424,214	15,964,095	9,582,695	1,144,098	225,430,452	291,648
Long-term debt	30,000,273	4,005,730	-	1,700,000	-	215,466
Inter-company debt & advances	-	-	16,141,969	-	-	-
Regulatory liabilities	9,019,251	-	(24,584)	12,419	(167,407)	-
Other deferred amounts & customer deposits	2,607,425	365,942	510,289	41,397	223,589	12,660
Employeee future benefits	8,771,277	-	483,875	-	16,079,772	-
Future income taxes	(8,329,248)	-	418,096	(95,900)	(9,920,344)	-
Total Liabilities	66,493,191	20,335,767	27,112,340	2,802,013	231,646,062	519,775
Shareholders' Equity	44,682,728	30,540,530	21,174,142	2,878,319	175,926,220	732,580
LIABILITIES & SHAREHOLDERS' EQUITY	$ 111,175,919	$ 50,876,296	$ 48,286,482	$ 5,680,333	$ 407,572,282	$ 1,252,355

Balance Sheet As of December 31, 2009 (Alphabetically Listed)	Hydro Hawkesbury Inc.	Hydro One Brampton Networks Inc.	Hydro One Networks Inc.	Hydro Ottawa Limited	Innisfil Hydro Distribution Systems Limited	Kenora Hydro Electric Corporation Ltd.
Cash & cash equivalents	2,384,441	(14,776,138)	68	1,041,143	(859,559)	558,193
Receivables	2,844,029	55,880,760	2,242,566,702	145,176,033	4,067,800	2,202,107
Inventory	126,957	1,159,393	5,762,418	7,088,436	321,224	221,177
Inter-company	-	-	-	-	12,300	(449,273)
Other current assets	51,404	677,878	12,844,206	762,971	214,687	44,373
Current assets	5,406,830	42,941,893	2,261,173,395	154,068,583	3,756,452	2,576,577
Property plant & equipment	3,414,207	473,087,722	7,117,885,840	938,572,439	45,430,084	13,176,502
Accumulated depreciation & amortization	(1,451,311)	(228,617,035)	(2,616,227,621)	(425,982,766)	(25,719,209)	(6,318,926)
	1,962,897	244,470,687	4,501,658,219	512,589,673	19,710,875	6,857,576
Regulatory assets (net)	(1,303,021)	11,534,894	455,527,123	14,862,783	2,797,922	153,033
Inter-company	-	-	0	-	-	-
Other non-current assets	157,654	16,739,338	150,467,280	155,668	285,955	613,707
Total Assets	$ 6,224,361	$ 315,686,812	$ 7,368,826,017	$ 681,676,707	$ 26,551,205	$ 10,200,892
Accounts payable & accrued charges	$ 2,516,797	$ 48,651,384	$ 457,243,627	$ 113,990,626	$ 4,491,557	$ 1,233,911
Current Portion of Future Income Taxes	(455,886)	-	6,216,588	-	(1,420,000)	-
Other current liabilities	-	1,108,573	42,813,680	(673,982)	253,928	(7,388)
Inter-company	-	-	1,683,562,284	2,120,397	-	30,653
Loans and notes payable, and current portion of long term debt	-	844,092	224,215,738	8,000,000	2,880,099	-
Current liabilities	2,060,911	50,604,049	2,414,051,918	123,437,041	6,205,584	1,257,177
Long-term debt	948,613	143,000,000	4,540,328	297,185,000	-	3,969,279
Inter-company debt & advances	-	-	2,342,716,584	-	4,382,000	-
Regulatory liabilities	-	804,057	1,707,564	1,399,276	36,601	19,536
Other deferred amounts & customer deposits	572,030	172,304	151,346,775	11,785,030	552,342	-
Employeee future benefits	-	5,783,000	521,251,271	4,982,681	-	141,134
Future income taxes	-	8,214,344	143,461,404	-	-	(362,189)
Total Liabilities	3,581,555	208,577,754	5,579,075,846	438,789,027	11,176,527	5,024,937
Shareholders' Equity	2,642,806	107,109,058	1,789,750,171	242,887,680	15,374,678	5,175,956
LIABILITIES & SHAREHOLDERS' EQUITY	$ 6,224,361	$ 315,686,812	$ 7,368,826,017	$ 681,676,707	$ 26,551,205	$ 10,200,892

Balance Sheet As of December 31, 2009 (Alphabetically Listed)	Kingston Hydro Corporation	Kitchener-Wilmot Hydro Inc.	Lakefront Utilities Inc.	Lakeland Power Distribution Ltd.	London Hydro Inc.	Middlesex Power Distribution Corporation
Cash & cash equivalents	4,197,958	28,117,397	2,141,428	(264,186)	4,876,102	1,629,721
Receivables	12,449,520	31,253,976	4,403,768	4,403,629	53,892,185	3,148,680
Inventory	1,125,725	3,284,381	238,012	262,181	3,858,069	217,800
Inter-company	-	-	-	-	-	-
Other current assets	102,278	1,289,902	46,718	154,817	1,056,901	42,388
Current assets	17,875,481	63,945,656	6,829,927	4,556,441	63,683,257	5,038,589
Property plant & equipment	43,586,787	268,456,464	17,756,451	21,423,286	360,481,161	18,835,735
Accumulated depreciation & amortization	(15,873,352)	(127,552,270)	(6,903,142)	(8,368,003)	(168,594,994)	(10,346,238)
	27,713,435	140,904,194	10,853,309	13,055,283	191,886,167	8,489,497
Regulatory assets (net)	727,231	2,790,983	2,190,895	1,381,177	(2,077,426)	1,693,296
Inter-company	250,000	-	-	-	-	-
Other non-current assets	-	1,334,279	-	-	-	-
Total Assets	$ 46,566,147	$ 208,975,112	$ 19,874,130	$ 18,992,901	$ 253,491,998	$ 15,221,382
Accounts payable & accrued charges	$ 9,660,621	$ 23,617,875	$ 3,295,695	$ 3,871,317	$ 45,352,578	$ 2,962,036
Current Portion of Future Income Taxes	(2,192,400)	-	(555,000)	-	-	-
Other current liabilities	56,952	52,467	17,700	(77,023)	1,664,107	46,277
Inter-company	-	-	-	272,834	7,137,003	713,915
Loans and notes payable, and current portion of long term debt	2,512,334	-	-	890,000	-	-
Current liabilities	10,037,507	23,670,342	2,758,395	4,957,127	54,153,688	3,722,229
Long-term debt	2,588,122	76,962,142	8,653,000	3,487,500	70,000,000	-
Inter-company debt & advances	10,880,619	-	-	-	-	5,300,000
Regulatory liabilities	1,898,678	50,779	(47,323)	-	-	-
Other deferred amounts & customer deposits	1,462,901	3,646,741	214,063	226,266	7,261,061	1,232,734
Employeee future benefits	1,006,338	5,337,119	264,156	-	9,414,100	53,372
Future income taxes	-	-	-	(757,631)	0	-
Total Liabilities	27,874,165	109,667,123	11,842,291	7,913,262	140,828,849	10,308,335
Shareholders' Equity	18,691,982	99,307,989	8,031,839	11,079,638	112,663,149	4,913,047
LIABILITIES & SHAREHOLDERS' EQUITY	$ 46,566,147	$ 208,975,112	$ 19,874,130	$ 18,992,901	$ 253,491,998	$ 15,221,382

Balance Sheet **As of December 31, 2009** **(Alphabetically Listed)**	Midland Power Utility Corporation	Milton Hydro Distribution Inc.	Newmarket - Tay Power Distribution Ltd.	Niagara Peninsula Energy Inc.	Niagara-on-the-Lake Hydro Inc.	Norfolk Power Distribution Inc.
Cash & cash equivalents	(847,663)	(264,598)	7,259,103	9,762,789	337,339	288,243
Receivables	3,338,876	13,773,777	6,426,554	23,887,197	4,284,902	9,311,255
Inventory	252,646	919,065	841,717	1,281,510	218,184	572,473
Inter-company	-	10,996	-	30,069	-	159,704
Other current assets	208,637	373,944	688,910	532,679	78,496	255,981
Current assets	2,952,496	14,813,185	15,216,284	35,494,243	4,918,922	10,587,657
Property plant & equipment	19,904,100	86,992,486	105,412,672	235,513,593	38,530,703	85,016,144
Accumulated depreciation & amortization	(10,546,691)	(44,074,818)	(55,458,126)	(121,202,466)	(18,485,600)	(36,317,916)
	9,357,409	42,917,668	49,954,546	114,311,127	20,045,103	48,698,228
Regulatory assets (net)	665,597	504,131	1,674,238	(7,629,013)	(369,176)	1,628,870
Inter-company	100	-	-	-	-	-
Other non-current assets	1,260,000	-	-	-	369,711	1,618,588
Total Assets	$ 14,235,601	$ 58,234,985	$ 66,845,067	$ 142,176,357	$ 24,964,561	$ 62,533,343
Accounts payable & accrued charges	$ 3,721,277	$ 11,846,501	$ 4,175,274	$ 15,719,913	$ 3,334,386	$ 7,646,550
Current Portion of Future Income Taxes	-	-	-	(1,295,826)	-	-
Other current liabilities	7,522	4,106	75,938	(423,691)	(11)	195,024
Inter-company	-	-	-	6,604,304	-	141,847
Loans and notes payable, and current portion of long term debt	1,422,519	-	19,312	1,576,810	3,964,405	559,802
Current liabilities	5,151,318	11,850,606	4,270,524	22,181,510	7,298,780	8,543,223
Long-term debt	-	14,934,210	23,742,821	33,863,745	-	24,855,100
Inter-company debt & advances	-	-	-	3,605,090	6,296,714	-
Regulatory liabilities	29,788	(66,481)	33,122	116,350	-	1,661,371
Other deferred amounts & customer deposits	205,240	4,858,073	3,887,556	1,334,023	406,992	178,141
Employeee future benefits	78,065	155,482	938,049	3,612,877	456,016	805,337
Future income taxes	-	(1,412,101)	-	-	(1,089,824)	-
Total Liabilities	5,464,411	30,319,789	32,872,072	64,713,595	13,368,679	36,043,173
Shareholders' Equity	8,771,190	27,915,195	33,972,995	77,462,763	11,595,882	26,490,170
LIABILITIES & SHAREHOLDERS' EQUITY	$ 14,235,601	$ 58,234,985	$ 66,845,067	$ 142,176,357	$ 24,964,561	$ 62,533,343

Balance Sheet **As of December 31, 2009** **(Alphabetically Listed)**	North Bay Hydro Distribution Limited	Northern Ontario Wires Inc.	Oakville Hydro Electricity Distribution Inc.	Orangeville Hydro Limited	Orillia Power Distribution Corporation	Oshawa PUC Networks Inc.
Cash & cash equivalents	9,398,403	705,483	5,129,658	1,308,960	133,695	17,029,455
Receivables	11,344,030	2,483,469	27,005,309	5,294,985	6,114,408	17,979,575
Inventory	796,498	286,226	4,748,786	270,823	669,226	608,383
Inter-company	1,194,378	33,191	-	-	683,989	184,920
Other current assets	271,278	66,266	476,444	147,169	82,368	176,940
Current assets	23,004,588	3,574,634	37,360,198	7,021,937	7,683,685	35,979,273
Property plant & equipment	80,605,593	6,795,580	189,667,878	29,378,796	33,343,088	130,552,826
Accumulated depreciation & amortization	(46,271,663)	(3,188,723)	(78,668,456)	(15,691,593)	(17,565,628)	(78,500,104)
	34,333,930	3,606,857	110,999,422	13,687,203	15,777,460	52,052,722
Regulatory assets (net)	2,423,310	306,717	(10,434,366)	(1,116,587)	862,941	(2,445,192)
Inter-company	-	-	-	65,000	-	-
Other non-current assets	-	-	3,130,452	540,000	8,915	-
Total Assets	$ 59,761,827	$ 7,488,208	$ 141,055,705	$ 20,197,553	$ 24,333,001	$ 85,586,803
Accounts payable & accrued charges	$ 8,822,787	$ 1,617,877	$ 33,465,183	$ 3,962,318	$ 4,865,442	$ 9,697,384
Current Portion of Future Income Taxes	(501,772)	2,089	-	-	(183,000)	-
Other current liabilities	483,244	3,676	657,078	527	66,608	145,400
Inter-company	139,874	-	-	-	141,383	-
Loans and notes payable, and current portion of long term debt	9,079	175,617	-	235,793	100,000	-
Current liabilities	8,953,211	1,799,259	34,122,261	4,198,638	4,990,432	9,842,784
Long-term debt	1,911,280	2,415,008	67,945,839	5,838,903	10,862,000	30,064,000
Inter-company debt & advances	19,511,601	-	(12,471,889)	-	-	-
Regulatory liabilities	(1,150)	-	-	540,000	(1,381)	-
Other deferred amounts & customer deposits	592,192	-	27,680,554	558,323	569,933	4,791,780
Employeee future benefits	4,269,035	44,220	7,277,252	208,135	556,027	9,684,100
Future income taxes	-	(3,416)	(22,835,104)	-	(1,758,000)	-
Total Liabilities	35,236,170	4,255,072	101,718,914	11,343,999	15,219,011	54,382,664
Shareholders' Equity	24,525,658	3,233,137	39,336,792	8,853,554	9,113,990	31,204,139
LIABILITIES & SHAREHOLDERS' EQUITY	$ 59,761,827	$ 7,488,208	$ 141,055,705	$ 20,197,553	$ 24,333,001	$ 85,586,803

Balance Sheet **As of December 31, 2009** **(Alphabetically Listed)**	Ottawa River Power Corporation	Parry Sound Power Corporation	Peterborough Distribution Incorporated	Port Colborne Hydro Inc.	PowerStream Inc.	PUC Distribution Inc.
Cash & cash equivalents	7,322,334	592,633	7,627,379	275	25,885,799	8,427,961
Receivables	3,819,871	1,815,013	11,920,129	3,758,591	164,065,600	12,662,727
Inventory	842,125	116,919	1,256,379	-	3,868,744	1,243,701
Inter-company	589,521	-	-	-	273,104	-
Other current assets	131,911	278,153	206,476	40,178	2,580,843	114,328
Current assets	12,705,761	2,802,717	21,010,364	3,799,043	196,674,090	22,448,717
Property plant & equipment	23,853,909	10,905,929	74,968,628	13,152,903	1,245,884,758	85,950,342
Accumulated depreciation & amortization	(15,633,695)	(6,855,301)	(26,568,257)	(1,683,380)	(597,964,297)	(46,258,843)
	8,220,214	4,050,628	48,400,371	11,469,524	647,920,461	39,691,499
Regulatory assets (net)	(4,583,331)	757,133	7,878,770	2,786,480	(1,508,480)	853,633
Inter-company	-	100	-	-	-	-
Other non-current assets	21,449	-	1,845,000	384,821	79,034,832	(2,940,000)
Total Assets	$ 16,364,093	$ 7,610,578	$ 79,134,505	$ 18,439,868	$ 922,120,903	$ 60,053,849
Accounts payable & accrued charges	$ 3,392,769	$ 1,831,874	$ 10,780,555	$ 508,044	$ 152,085,219	$ 12,773,896
Current Portion of Future Income Taxes	-	-	-	(4,677)	-	-
Other current liabilities	(53,027)	9,276	-	77,215	5,463,870	(31,570)
Inter-company	-	637,006	-	18,020,344	275,566	-
Loans and notes payable, and current portion of long term debt	101,243	-	775,161	-	44,691,041	3,499,600
Current liabilities	3,440,985	2,478,156	11,555,716	18,600,926	202,515,696	16,241,925
Long-term debt	5,585,838	2,433,728	15,510,743	-	173,090,574	-
Inter-company debt & advances	-	-	23,157,680	-	182,429,859	26,534,040
Regulatory liabilities	-	3,536	66,220	-	61,655,972	254,035
Other deferred amounts & customer deposits	611,567	128,229	1,091,215	-	22,146,022	189,880
Employeee future benefits	-	-	7,309	-	12,036,282	-
Future income taxes	(861,382)	-	-	241,554	-	(2,940,000)
Total Liabilities	8,777,009	5,043,649	51,388,883	18,842,480	653,874,405	40,279,880
Shareholders' Equity	7,587,084	2,566,929	27,745,622	(402,612)	268,246,498	19,773,969
LIABILITIES & SHAREHOLDERS' EQUITY	$ 16,364,093	$ 7,610,578	$ 79,134,505	$ 18,439,868	$ 922,120,903	$ 60,053,849

Balance Sheet As of December 31, 2009 (Alphabetically Listed)	Renfrew Hydro Inc.	Rideau St. Lawrence Distribution Inc.	Sioux Lookout Hydro Inc.	St. Thomas Energy Inc.	Thunder Bay Hydro Electricity Distribution Inc.	Tillsonburg Hydro Inc.
Cash & cash equivalents	2,431,940	520,361	1,008,668	127,485	9,286,819	891,931
Receivables	1,939,619	2,164,707	1,671,703	4,798,930	8,716,389	2,802,446
Inventory	263,477	230,906	52,707	-	1,571,869	320,024
Inter-company	361	-	-	11,579	1,360,277	-
Other current assets	71,633	42,844	245,157	4,929	199,595	14,203
Current assets	4,707,031	2,958,818	2,978,236	4,942,924	21,134,949	4,028,603
Property plant & equipment	12,178,306	5,759,089	7,163,515	38,229,411	142,000,546	14,120,413
Accumulated depreciation & amortization	(7,819,389)	(1,643,983)	(2,588,353)	(19,274,043)	(79,903,059)	(8,135,672)
	4,358,916	4,115,106	4,575,162	18,955,369	62,097,487	5,984,742
Regulatory assets (net)	(1,191,245)	1,165,900	695,892	(541,024)	7,184,000	351,731
Inter-company	-	-	-	-	-	-
Other non-current assets	28,380	-	-	802,279	894,171	88,336
Total Assets	$ 7,903,082	$ 8,239,824	$ 8,249,290	$ 24,159,546	$ 91,310,608	$ 10,453,412
Accounts payable & accrued charges	$ 1,516,646	$ 1,556,168	$ 2,184,273	$ 2,503,656	$ 4,945,971	$ 1,989,056
Current Portion of Future Income Taxes	(16,828)	-	-	-	-	-
Other current liabilities	(2,611)	13,540	(19,424)	51,008	(84,931)	-
Inter-company	54,840	1,798,031	-	1,250,591	23,139	(114,001)
Loans and notes payable, and current portion of long term debt	2,705,168	1,195,903	229,475	500,000	367,673	-
Current liabilities	4,257,215	4,563,642	2,394,324	4,305,256	5,251,851	1,875,055
Long-term debt	241,029	70,970	2,827,444	7,714,426	7,484,747	-
Inter-company debt & advances	-	-	-	-	33,490,500	-
Regulatory liabilities	5,061	54,508	62,275	-	910,352	-
Other deferred amounts & customer deposits	174,602	70,992	158,602	737,548	1,214,280	92,189
Employeee future benefits	-	-	41,962	-	2,114,763	-
Future income taxes	-	-	(113,196)	-	(3,825,000)	-
Total Liabilities	4,677,908	4,760,112	5,371,412	12,757,230	46,641,493	1,967,244
Shareholders' Equity	3,225,174	3,479,712	2,877,877	11,402,317	44,669,115	8,486,169
LIABILITIES & SHAREHOLDERS' EQUITY	$ 7,903,082	$ 8,239,824	$ 8,249,290	$ 24,159,546	$ 91,310,608	$ 10,453,412

Balance Sheet **As of December 31, 2009** **(Alphabetically Listed)**	Toronto Hydro-Electric System Limited	Veridian Connections Inc.	Wasaga Distribution Inc.	Waterloo North Hydro Inc.	Welland Hydro-Electric System Corp.	Wellington North Power Inc.
Cash & cash equivalents	89,419,562	6,377,083	1,621,574	226,635	7,190,832	232,421
Receivables	462,252,719	51,097,128	3,477,964	25,172,902	7,592,485	1,446,515
Inventory	6,223,524	1,846,231	-	2,410,081	565,341	-
Inter-company	5,525	-	-	17,799	96,333	-
Other current assets	3,210,078	257,577	461,765	442,092	20,116	-
Current assets	561,111,408	59,578,019	5,561,303	28,269,509	15,465,107	1,678,936
Property plant & equipment	4,056,003,856	320,602,200	19,476,482	207,953,567	46,196,437	10,230,195
Accumulated depreciation & amortization	(2,124,641,603)	(171,600,321)	(10,771,927)	(97,922,615)	(25,262,201)	(5,383,107)
	1,931,362,252	149,001,879	8,704,555	110,030,952	20,934,236	4,847,087
Regulatory assets (net)	10,567,207	1,018,815	(1,191,432)	(9,187,139)	1,042,865	(423,151)
Inter-company	-	-	-	-	-	-
Other non-current assets	7,614,742	10,880,327	-	50,779	2,935,788	245,145
Total Assets	$ 2,510,655,608	$ 220,479,040	$ 13,074,426	$ 129,164,101	$ 40,377,996	$ 6,348,018
Accounts payable & accrued charges	$ 309,563,272	$ 40,054,904	$ 4,041,955	$ 20,789,862	$ 5,386,285	$ 2,315,606
Current Portion of Future Income Taxes	-	-	-	-	-	-
Other current liabilities	10,038,558	1,329,811	342	763,727	142,439	(35,464)
Inter-company	497,982,216	4,910,139	(3,316,355)	692,678	-	-
Loans and notes payable, and current portion of long term debt	-	672,056	-	4,452,781	8,849	-
Current liabilities	817,584,045	46,966,910	725,943	26,699,048	5,537,573	2,280,142
Long-term debt	-	83,809,886	-	33,513,211	3,700,000	1,185,015
Inter-company debt & advances	666,275,250	-	3,593,269	-	13,499,953	-
Regulatory liabilities	-	580,480	-	-	2,685,820	-
Other deferred amounts & customer deposits	43,705,583	8,320,104	-	2,057,502	301,140	349,689
Employeee future benefits	154,448,000	-	-	3,777,964	1,481,494	89,242
Future income taxes	-	11,223,146	(97,510)	-	-	-
Total Liabilities	1,682,012,878	150,900,526	4,221,701	66,047,725	27,205,980	3,904,088
Shareholders' Equity	828,642,730	69,578,514	8,852,725	63,116,376	13,172,016	2,443,930
LIABILITIES & SHAREHOLDERS' EQUITY	$ 2,510,655,608	$ 220,479,040	$ 13,074,426	$ 129,164,101	$ 40,377,996	$ 6,348,018

Balance Sheet As of December 31, 2009 (Alphabetically Listed)	West Coast Huron Energy Inc.	West Perth Power Inc.	Westario Power Inc.	Whitby Hydro Electric Corporation	Woodstock Hydro Services Inc.	Total for Overall Industry
Cash & cash equivalents	500,994	836,125	3,026,348	3,634,634	2,157,301	363,374,543
Receivables	1,435,205	1,307,154	8,348,906	16,396,215	7,151,099	3,944,740,460
Inventory	400,511	75,542	743,073	907,556	943,213	88,572,531
Inter-company	-	10,998	-	52,767	121,214	25,900,910
Other current assets	8,302	99,418	348,537	90,312	140,731	39,695,201
Current assets	2,345,012	2,329,239	12,466,864	21,081,484	10,513,558	4,462,283,645
Property plant & equipment	6,430,595	4,729,208	43,842,109	126,600,841	35,826,147	20,216,463,396
Accumulated depreciation & amortization	(2,121,710)	(3,020,301)	(14,414,929)	(64,107,824)	(15,214,319)	(9,066,170,761)
	4,308,885	1,708,907	29,427,181	62,493,017	20,611,828	11,150,292,634
Regulatory assets (net)	(423,872)	(359,569)	4,331,212	(5,286,210)	(231,452)	497,358,853
Inter-company	-	-	-	-	-	1,392,650
Other non-current assets	-	-	255,209	-	169,500	337,923,387
Total Assets	$ 6,230,025	$ 3,678,576	$ 46,480,467	$ 78,288,291	$ 31,063,434	$16,449,251,170
Accounts payable & accrued charges	$ 933,190	$ 860,173	$ 6,591,544	$ 10,065,457	$ 5,948,371	$ 1,798,238,955
Current Portion of Future Income Taxes	-	-	-	-	-	(7,734,985)
Other current liabilities	(16,792)	(23,347)	-	32,905	69,115	65,232,434
Inter-company	-	-	-	-	-	2,483,526,990
Loans and notes payable, and current portion of long term debt	-	-	2,112,106	-	-	328,460,453
Current liabilities	916,398	836,826	8,703,650	10,098,361	6,017,486	4,667,723,847
Long-term debt	974,454	1,183,391	13,125,554	28,337,942	10,941,862	1,786,001,020
Inter-company debt & advances	-	-	-	-	-	3,467,350,861
Regulatory liabilities	-	(146,726)	676,242	-	-	86,297,429
Other deferred amounts & customer deposits	249,278	64,988	-	1,122,828	1,153,363	382,531,599
Employeee future benefits	-	-	334,353	-	1,118,833	857,703,447
Future income taxes	-	-	67,000	(2,300,548)	(2,460,100)	86,840,149
Total Liabilities	2,140,130	1,938,479	22,906,799	37,258,584	16,771,444	11,334,448,354
Shareholders' Equity	4,089,895	1,740,098	23,573,668	41,029,707	14,291,990	5,114,802,816
LIABILITIES & SHAREHOLDERS' EQUITY	$ 6,230,025	$ 3,678,576	$ 46,480,467	$ 78,288,291	$ 31,063,434	$ 16,449,251,170

Income Statement For the year ended December 31, 2009 (Alphabetically Listed)	Algoma Power Inc.	Atikokan Hydro Inc.	Bluewater Power Distribution Corporation	Brant County Power Inc.	Brantford Power Inc.	Burlington Hydro Inc.
Power and distribution revenue	$ 32,180,639	$ 3,129,068	$ 72,629,059	$ 21,730,666	$ 87,729,824	$ 128,138,722
Cost of power and related costs	14,638,690	1,824,212	53,779,084	15,685,092	72,025,901	100,310,832
	17,541,949	1,304,856	18,849,975	6,045,574	15,703,923	27,827,891
Other income	(8,959)	11,420	1,143,302	38,055	484,428	1,159,449
Expenses						
Operating	1,667,413	304,487	3,253,890	503,294	1,057,112	4,126,702
Maintenance	3,183,635	30,962	162,468	580,480	1,723,356	2,306,816
Administrative	3,764,706	535,268	6,728,720	2,568,216	4,947,601	6,771,107
Other	12,148,503	22,229	296,015	(2,588)	162,824	539,939
Depreciation and amortization	3,651,441	174,190	3,968,013	1,015,883	3,166,455	6,364,933
Financing	1,830,707	75,833	1,471,746	327,697	2,024,039	3,759,718
	26,246,404	1,142,969	15,880,852	4,992,982	13,081,387	23,869,214
PILs and Income Taxes						
Current	1,033,536	-	1,293,000	-	1,930,422	1,621,745
Future	-	-	-	342,923	(1,042,511)	(516,782)
	1,033,536	-	1,293,000	342,923	887,911	1,104,963
Net Income	$ (9,746,950)	$ 173,307	$ 2,819,425	$ 747,724	$ 2,219,054	$ 4,013,163

Income Statement For the year ended December 31, 2009 (Alphabetically Listed)	Cambridge and North Dumfries Hydro Inc.	Canadian Niagara Power Inc.	Centre Wellington Hydro Ltd.	Chapleau Public Utilities Corporation	Chatham-Kent Hydro Inc.	Clinton Power Corporation
Power and distribution revenue	$ 126,064,621	$ 37,251,139	$ 12,535,427	$ 2,850,672	$ 69,406,413	$ 2,687,923
Cost of power and related costs	104,986,187	26,286,316	9,729,968	2,176,584	55,871,837	2,033,536
	21,078,434	10,964,824	2,805,459	674,088	13,534,576	654,386
Other income	617,298	922,102	89,978	18,177	639,688	8,870
Expenses						
Operating	2,370,468	780,256	294,136	147,030	642,109	87,466
Maintenance	1,005,334	1,017,747	300,079	-	885,043	167,476
Administrative	6,535,860	2,925,080	1,084,009	343,869	4,022,798	296,265
Other	3,800	191,957	44,478	9,121	200,000	39
Depreciation and amortization	6,045,689	2,942,475	558,957	44,301	3,625,261	72,107
Financing	1,898,918	2,030,389	376,559	6,165	1,685,787	38,487
	17,860,069	9,887,905	2,658,218	550,485	11,060,999	661,840
PILs and Income Taxes						
Current	1,120,261	442,170	31,592	-	1,010,704	-
Future	26,268	-	(32,308)	-	-	-
	1,146,529	442,170	(716)	-	1,010,704	-
Net Income	$ 2,689,134	$ 1,556,851	$ 237,934	$ 141,780	$ 2,102,561	$ 1,417

Income Statement For the year ended December 31, 2009 (Alphabetically Listed)	COLLUS Power Corporation	Cooperative Hydro Embrun Inc.	E.L.K. Energy Inc.	Enersource Hydro Mississauga Inc.	EnWin Utilities Ltd.	Erie Thames Powerlines Corporation
Power and distribution revenue	$ 29,518,915	$ 2,053,591	$ 19,040,556	$ 695,728,461	$ 209,291,340	$ 36,759,103
Cost of power and related costs	24,064,557	1,449,009	14,418,495	578,088,981	160,940,319	30,739,578
	5,454,359	604,582	4,622,061	117,639,480	48,351,022	6,019,525
Other income	160,454	21,328	526,002	10,849,345	3,051,022	250,918
Expenses						
Operating	257,730	18,349	298,927	18,251,383	2,007,013	51,217
Maintenance	1,645,455	29,551	506,972	3,529,129	2,527,893	366,619
Administrative	2,011,647	361,102	1,692,293	28,239,990	15,413,932	3,916,431
Other	-	1,650	18,984	1,224,725	902,361	45,007
Depreciation and amortization	1,004,161	125,101	852,414	34,489,385	10,773,764	1,017,711
Financing	179,149	1,482	232,970	17,976,042	3,545,113	652,455
	5,098,142	537,235	3,602,560	103,710,654	35,170,076	6,049,440
PILs and Income Taxes						
Current	100,906	-	562,106	5,941,571	6,012,482	92,000
Future	(32,937)	5,012	-	309,202	-	-
	67,969	5,012	562,106	6,250,773	6,012,482	92,000
Net Income	$ 448,702	$ 83,663	$ 983,397	$ 18,527,398	$ 10,219,486	$ 129,004

Income Statement For the year ended December 31, 2009 (Alphabetically Listed)	Espanola Regional Hydro Distribution Corporation	Essex Powerlines Corporation	Festival Hydro Inc.	Fort Frances Power Corporation	Greater Sudbury Hydro Inc.	Grimsby Power Incorporated
Power and distribution revenue	$ 5,967,416	$ 53,677,773	$ 53,219,921	$ 7,860,262	$ 99,778,804	$ 16,963,004
Cost of power and related costs	4,614,021	43,630,093	43,686,561	6,308,863	77,140,065	13,435,689
	1,353,395	10,047,680	9,533,360	1,551,398	22,638,738	3,527,316
Other income	44,784	285,955	380,565	251,517	(1,166,820)	141,967
Expenses						
Operating	316,993	854,338	561,058	194,356	3,652,054	197,350
Maintenance	254,989	1,201,517	883,115	130,396	1,502,331	380,246
Administrative	536,644	3,133,328	2,210,862	991,807	6,280,433	1,162,564
Other	20,327	118,209	78,882	14,092	368,452	30,314
Depreciation and amortization	191,274	2,320,651	2,525,759	348,721	4,634,610	967,542
Financing	107,542	771,480	1,189,620	181,674	4,473,684	440,872
	1,427,768	8,399,523	7,449,296	1,861,046	20,911,564	3,178,888
PILs and Income Taxes						
Current	-	582,521	988,000	(466)	652,158	(625)
Future	-	-	-	-	(260,260)	131,123
	-	582,521	988,000	(466)	391,898	130,498
Net Income	$ (29,589)	$ 1,351,591	$ 1,476,629	$ (57,665)	$ 168,456	$ 359,896

Income Statement For the year ended December 31, 2009 (Alphabetically Listed)	Guelph Hydro Electric Systems Inc.	Haldimand County Hydro Inc.	Halton Hills Hydro Inc.	Hearst Power Distribution Company Limited	Horizon Utilities Corporation	Hydro 2000 Inc.
Power and distribution revenue	$ 120,996,522	$ 47,065,696	$ 45,739,267	$ 6,799,001	$ 451,394,349	$ 2,435,056
Cost of power and related costs	96,804,232	33,184,970	36,100,747	5,886,460	362,624,652	2,089,909
	24,192,290	13,880,726	9,638,520	912,541	88,769,697	345,147
Other income	1,629,375	671,696	672,927	50,630	1,381,154	20,015
Expenses						
Operating	1,273,896	1,229,703	819,741	88,075	14,416,952	10,512
Maintenance	1,809,238	2,365,865	173,136	274,809	3,882,635	9,184
Administrative	6,484,215	3,353,068	3,435,317	483,908	20,479,058	248,563
Other	295,140	115,950	(255,352)	-	1,221,120	100
Depreciation and amortization	6,491,663	2,688,285	2,257,848	103,155	23,295,450	52,384
Financing	2,792,524	697,784	1,020,488	225,197	9,900,326	27,030
	19,146,675	10,450,656	7,451,178	1,175,145	73,195,541	347,773
PILs and Income Taxes						
Current	3,329,003	1,519,769	1,082,698	10,588	5,502,940	10,221
Future	-	(119,835)	-	(70,100)	-	(7,410)
	3,329,003	1,399,934	1,082,698	(59,512)	5,502,940	2,811
Net Income	$ 3,345,987	$ 2,701,833	$ 1,777,571	$ (152,462)	$ 11,452,370	$ 14,579

Income Statement For the year ended December 31, 2009 (Alphabetically Listed)	Hydro Hawkesbury Inc.	Hydro One Brampton Networks Inc.	Hydro One Networks Inc.	Hydro Ottawa Limited	Innisfil Hydro Distribution Systems Limited	Kenora Hydro Electric Corporation Ltd.
Power and distribution revenue	$ 11,869,926	$ 347,492,512	$ 3,097,909,770	$ 734,255,360	$ 26,571,811	$ 10,066,923
Cost of power and related costs	10,647,223	285,513,279	2,040,591,725	587,958,063	18,877,110	7,883,158
	1,222,703	61,979,233	1,057,318,045	146,297,297	7,694,700	2,183,765
Other income	26,052	903,635	45,531,647	3,256,304	113,680	109,021
Expenses						
Operating	50,227	3,564,057	76,909,943	11,364,064	694,259	172,748
Maintenance	159,652	3,159,225	226,990,953	5,171,078	569,000	373,025
Administrative	578,080	10,862,165	202,148,099	35,436,389	2,457,389	1,155,836
Other	15,766	938,034	16,275,174	3,400,162	11,315	12,478
Depreciation and amortization	153,992	16,490,910	266,834,808	40,852,832	1,849,152	436,107
Financing	92,866	10,054,074	125,089,832	14,971,889	537,949	85,869
	1,050,583	45,068,465	914,248,809	111,196,414	6,119,063	2,236,063
PILs and Income Taxes						
Current	(59,831)	5,019,622	28,213,470	12,376,712	20,747	5,262
Future	89,664	3,097,195	-	-	460,756	-
	29,833	8,116,817	28,213,470	12,376,712	481,503	5,262
Net Income	$ 168,338	$ 9,697,586	$ 160,387,413	$ 25,980,476	$ 1,207,814	$ 51,460

Income Statement **For the year ended December 31, 2009** **(Alphabetically Listed)**	Kingston Hydro Corporation	Kitchener-Wilmot Hydro Inc.	Lakefront Utilities Inc.	Lakeland Power Distribution Ltd.	London Hydro Inc.	Middlesex Power Distribution Corporation
Power and distribution revenue	$ 64,314,546	$ 176,381,810	$ 23,959,691	$ 20,890,486	$ 308,713,898	$ 18,272,705
Cost of power and related costs	53,948,336	143,134,762	19,583,913	16,319,947	251,625,275	15,131,901
	10,366,210	33,247,048	4,375,778	4,570,539	57,088,622	3,140,804
Other income	83,368	1,374,196	110,472	163,710	2,006,877	169,734
Expenses						
Operating	1,940,051	2,815,696	505,675	196,371	6,738,103	95,533
Maintenance	776,190	3,953,941	139,614	832,493	5,623,690	308,321
Administrative	2,600,324	5,433,766	1,209,936	1,795,704	15,214,677	1,230,889
Other	151,661	522,585	53,482	10,065	103,291	7,500
Depreciation and amortization	2,086,472	9,386,316	893,443	952,100	15,535,769	667,033
Financing	780,453	4,877,571	587,170	223,758	4,248,195	370,676
	8,335,151	26,989,875	3,389,319	4,010,492	47,463,724	2,679,952
PILs and Income Taxes						
Current	912,402	2,964,835	355,241	229,224	3,305,332	126,628
Future	36,950	-	(10,000)	160,905	-	-
	949,352	2,964,835	345,241	390,129	3,305,332	126,628
Net Income	$ 1,165,075	$ 4,666,534	$ 751,690	$ 333,628	$ 8,326,443	$ 503,958

Income Statement For the year ended December 31, 2009 (Alphabetically Listed)	Midland Power Utility Corporation	Milton Hydro Distribution Inc.	Newmarket - Tay Power Distribution Ltd.	Niagara Peninsula Energy Inc.	Niagara-on-the-Lake Hydro Inc.	Norfolk Power Distribution Inc.
Power and distribution revenue	$ 19,913,915	$ 64,856,570	$ 70,095,452	$ 123,207,068	$ 17,333,975	$ 40,118,720
Cost of power and related costs	16,591,122	52,697,568	54,537,190	95,684,413	12,653,763	28,763,185
	3,322,793	12,159,002	15,558,262	27,522,656	4,680,211	11,355,535
Other income	140,720	766,533	2,744,173	464,429	213,793	88,473
Expenses						
Operating	325,787	685,613	963,225	3,152,388	399,162	1,060,932
Maintenance	337,863	991,549	1,218,466	2,390,127	439,868	1,025,443
Administrative	1,124,924	3,688,648	4,363,785	7,502,419	978,864	2,445,657
Other	31,421	75,000	915,432	215,253	42,555	124,305
Depreciation and amortization	684,753	2,968,831	4,270,471	7,754,076	1,299,342	2,517,025
Financing	58,067	1,107,221	1,490,026	2,819,522	706,058	1,270,617
	2,562,816	9,516,862	13,221,404	23,833,785	3,865,849	8,443,979
PILs and Income Taxes						
Current	68,873	1,036,250	1,778,792	1,656,184	376,432	912,000
Future	-	(65,927)	-	-	(50,465)	-
	68,873	970,323	1,778,792	1,656,184	325,967	912,000
Net Income	$ 831,824	$ 2,438,350	$ 3,302,238	$ 2,497,116	$ 702,189	$ 2,088,029

Income Statement For the year ended December 31, 2009 (Alphabetically Listed)	North Bay Hydro Distribution Limited	Northern Ontario Wires Inc.	Oakville Hydro Electricity Distribution Inc.	Orangeville Hydro Limited	Orillia Power Distribution Corporation	Oshawa PUC Networks Inc.
Power and distribution revenue	$ 51,337,172	$ 12,230,109	$ 133,705,112	$ 23,633,975	$ 29,895,170	$ 94,501,807
Cost of power and related costs	40,845,601	9,636,255	104,453,743	18,961,502	23,033,104	74,655,910
	10,491,571	2,593,853	29,251,368	4,672,472	6,862,066	19,845,898
Other income	292,662	34,709	2,515,962	138,669	62,212	490,006
Expenses						
Operating	690,785	435,765	3,846,220	329,817	916,577	589,965
Maintenance	1,069,450	236,302	2,005,361	430,459	817,793	1,067,491
Administrative	3,195,707	1,351,771	4,372,432	1,616,462	2,181,022	7,140,375
Other	2,044,938	1,969	940,679	5,196	64,961	291,629
Depreciation and amortization	2,581,212	315,113	10,390,567	985,671	1,435,997	4,430,136
Financing	1,023,906	129,763	4,953,568	355,008	668,677	1,976,892
	10,605,998	2,470,682	26,508,827	3,722,614	6,085,027	15,496,488
PILs and Income Taxes						
Current	583,406	33,549	3,163,137	370,750	299,783	1,923,557
Future	(501,772)	(7,730)	(673,879)	-	(6,000)	-
	81,634	25,819	2,489,258	370,750	293,783	1,923,557
Net Income	$ 96,601	$ 132,062	$ 2,769,245	$ 717,778	$ 545,467	$ 2,915,859

Income Statement For the year ended December 31, 2009 (Alphabetically Listed)	Ottawa River Power Corporation	Parry Sound Power Corporation	Peterborough Distribution Incorporated	Port Colborne Hydro Inc.	PowerStream Inc.	PUC Distribution Inc.
Power and distribution revenue	$ 17,934,613	$ 8,511,439	$ 75,362,482	$ 19,877,711	$ 775,213,917	$ 61,867,885
Cost of power and related costs	14,257,639	6,746,090	61,066,555	14,627,485	621,719,315	46,144,077
	3,676,974	1,765,350	14,295,927	5,250,226	153,494,602	15,723,808
Other income	318,739	33,139	1,273,002	(750,882)	1,742,956	193,865
Expenses						
Operating	330,997	57,300	1,756,212	360,324	13,361,528	2,892,380
Maintenance	613,328	283,648	1,291,646	442,988	9,322,325	2,119,240
Administrative	1,475,058	904,831	3,514,571	2,654,847	36,232,909	2,926,949
Other	-	-	1,152,204	83,013	2,685,120	55,850
Depreciation and amortization	675,335	384,027	3,222,790	376,757	42,124,601	3,059,645
Financing	473,972	193,337	1,694,699	395,947	21,886,277	2,070,793
	3,568,690	1,823,143	12,632,123	4,313,877	125,612,760	13,124,856
PILs and Income Taxes						
Current	72,916	11,762	1,060,000	40,757	8,561,170	92,000
Future	-	-	-	-	-	880,000
	72,916	11,762	1,060,000	40,757	8,561,170	972,000
Net Income	$ 354,107	$ (36,416)	$ 1,876,807	$ 144,710	$ 21,063,628	$ 1,820,817

Income Statement For the year ended December 31, 2009 (Alphabetically Listed)	Renfrew Hydro Inc.	Rideau St. Lawrence Distribution Inc.	Sioux Lookout Hydro Inc.	St. Thomas Energy Inc.	Thunder Bay Hydro Electricity Distribution Inc.	Tillsonburg Hydro Inc.
Power and distribution revenue	$ 9,586,597	$ 11,155,173	$ 5,384,196	$ 29,535,240	$ 92,462,215	$ 17,985,498
Cost of power and related costs	7,927,856	8,978,754	3,497,911	23,143,921	74,346,574	15,174,062
	1,658,741	2,176,418	1,886,285	6,391,319	18,115,641	2,811,436
Other income	46,336	88,358	15,643	143,231	358,415	41,438
Expenses						
Operating	206,387	232,774	396,302	555,092	2,899,470	854,849
Maintenance	145,465	292,592	94,701	501,616	3,299,553	186,094
Administrative	680,569	1,092,486	649,058	2,190,314	5,471,747	833,374
Other	-	22,699	300,979	117,957	178,000	222,616
Depreciation and amortization	417,125	277,765	266,547	1,308,810	4,712,063	551,911
Financing	221,495	80,116	65,526	577,537	343,561	14,844
	1,671,041	1,998,433	1,773,113	5,251,325	16,904,395	2,663,688
PILs and Income Taxes						
Current	21,172	28,706	35,709	509,687	734,000	21,641
Future	-	-	-	-	(3,825,000)	-
	21,172	28,706	35,709	509,687	(3,091,000)	21,641
Net Income	$ 12,865	$ 237,638	$ 93,105	$ 773,538	$ 4,660,661	$ 167,544

Income Statement For the year ended December 31, 2009 (Alphabetically Listed)	Toronto Hydro-Electric System Limited	Veridian Connections Inc.	Wasaga Distribution Inc.	Waterloo North Hydro Inc.	Welland Hydro-Electric System Corp.	Wellington North Power Inc.
Power and distribution revenue	$ 2,131,642,570	$ 243,940,027	$ 11,792,847	$ 105,761,804	$ 40,338,853	$ 7,302,177
Cost of power and related costs	1,649,332,663	197,332,492	7,874,479	79,978,881	32,059,673	5,379,530
	482,309,907	46,607,535	3,918,368	25,782,923	8,279,180	1,922,647
Other income	9,034,351	1,768,737	189,437	329,021	111,673	225,607
Expenses						
Operating	49,045,106	4,024,950	27,231	3,463,613	1,317,886	234,515
Maintenance	46,460,132	2,393,702	502,293	1,395,024	1,313,154	209,605
Administrative	83,353,278	13,050,184	1,475,780	3,944,669	2,162,318	704,345
Other	11,842,023	131,835	26,179	311,160	82,691	11,354
Depreciation and amortization	155,467,507	12,524,859	698,791	6,833,794	1,732,181	351,957
Financing	72,932,740	5,058,885	240,695	3,202,600	989,261	100,483
	419,100,785	37,184,415	2,970,969	19,150,860	7,597,491	1,612,258
PILs and Income Taxes						
Current	21,242,454	4,258,155	395,014	2,013,033	288,430	43,082
Future	-	-	1,869	-	-	-
	21,242,454	4,258,155	396,883	2,013,033	288,430	43,082
Net Income	$ 51,001,018	$ 6,933,702	$ 739,953	$ 4,948,051	$ 504,932	$ 492,913

Income Statement For the year ended December 31, 2009 (Alphabetically Listed)	West Coast Huron Energy Inc.	West Perth Power Inc.	Westario Power Inc.	Whitby Hydro Electric Corporation	Woodstock Hydro Services Inc.	Total for Overall Industry
Power and distribution revenue	$ 8,736,104	$ 5,123,074	$ 37,935,046	$ 72,628,672	$ 28,007,971	$ 11,840,237,804
Cost of power and related costs	6,783,076	4,234,627	29,407,699	54,030,176	21,258,813	8,963,585,835
	1,953,028	888,447	8,527,347	18,598,496	6,749,158	2,876,651,969
Other income	105,169	127,845	465,712	83,921	156,465	102,249,860
Expenses						
Operating	218,927	123,327	238,670	1,843,244	719,297	263,337,352
Maintenance	152,295	95,748	1,452,470	1,897,551	630,310	368,019,314
Administrative	1,064,094	574,501	2,886,334	4,715,155	1,976,033	635,577,381
Other	-	43	123,169	-	123,276	61,541,296
Depreciation and amortization	257,057	206,127	1,791,243	4,597,113	1,871,315	765,251,029
Financing	79,120	87,706	(76,370)	2,012,142	581,034	351,647,506
	1,771,493	1,087,452	6,415,515	15,065,205	5,901,266	2,445,373,879
PILs and Income Taxes						
Current	47,781	-	429,990	1,601,769	587,559	142,638,447
Future	-	-	293,581	-	(174,880)	(1,562,348)
	47,781	-	723,571	1,601,769	412,679	141,076,099
Net Income	$ 238,923	$ (71,160)	$ 1,853,974	$ 2,015,442	$ 591,678	$ 392,451,851

Financial Ratios **For the year ended December 31, 2009** **(Alphabetically Listed)**	Algoma Power Inc.	Atikokan Hydro Inc.	Bluewater Power Distribution Corporation	Brant County Power Inc.	Brantford Power Inc.	Burlington Hydro Inc.
Liquidity Ratios						
Current Ratio (Current Assets/Current Liabilities)	7.19	3.12	1.72	1.85	2.01	1.78
Leverage Ratios						
Debt Ratio (Long Term Financing/Total Assets)	56%	57%	30%	19%	45%	36%
Debt to Equity Ratio (Long Term Financing/Total Equity)	1.40	2.08	0.92	0.30	1.12	0.85
Interest Coverage (EBIT/Interest Charges)	-3.76	3.29	3.79	4.33	2.54	2.36
Profitability Ratios						
Financial Statement Return on Assets (Net Income/Total Assets)	-12.07%	4.73%	4.37%	2.82%	2.72%	2.99%
Financial Statement Return on Equity (Net Income/Total Equity)	-29.93%	17.13%	13.41%	4.53%	6.83%	7.09%

Financial Ratios For the year ended December 31, 2009 (Alphabetically Listed)	Cambridge and North Dumfries Hydro Inc.	Canadian Niagara Power Inc.	Centre Wellington Hydro Ltd.	Chapleau Public Utilities Corporation	Chatham-Kent Hydro Inc.	Clinton Power Corporation
Liquidity Ratios						
Current Ratio (Current Assets/Current Liabilities)	2.13	1.00	3.54	3.00	1.50	0.66
Leverage Ratios						
Debt Ratio (Long Term Financing/Total Assets)	31%	55%	37%	0%	34%	0%
Debt to Equity Ratio (Long Term Financing/Total Equity)	0.66	2.40	0.81	0.00	0.80	0.00
Interest Coverage (EBIT/Interest Charges)	3.02	1.98	1.63	24.00	2.85	1.04
Profitability Ratios						
Financial Statement Return on Assets (Net Income/Total Assets)	2.02%	2.38%	1.75%	6.92%	3.04%	0.05%
Financial Statement Return on Equity (Net Income/Total Equity)	4.27%	10.38%	3.81%	8.63%	7.17%	0.22%

Financial Ratios **For the year ended December 31, 2009** **(Alphabetically Listed)**	COLLUS Power Corporation	Cooperative Hydro Embrun Inc.	E.L.K. Energy Inc.	Enersource Hydro Mississauga Inc.	EnWin Utilities Ltd.	Erie Thames Powerlines Corporation
Liquidity Ratios						
Current Ratio (Current Assets/Current Liabilities)	1.10	3.85	3.64	1.40	0.76	0.78
Leverage Ratios						
Debt Ratio (Long Term Financing/Total Assets)	9%	72%	46%	47%	23%	30%
Debt to Equity Ratio (Long Term Financing/Total Equity)	0.16	4.52	1.59	1.41	0.66	1.02
Interest Coverage (EBIT/Interest Charges)	3.88	60.85	7.63	2.38	5.58	1.34
Profitability Ratios						
Financial Statement Return on Assets (Net Income/Total Assets)	2.27%	2.10%	4.53%	3.01%	4.61%	0.46%
Financial Statement Return on Equity (Net Income/Total Equity)	4.32%	13.21%	15.84%	8.99%	13.49%	1.55%

Financial Ratios **For the year ended December 31, 2009** **(Alphabetically Listed)**	Espanola Regional Hydro Distribution Corporation	Essex Powerlines Corporation	Festival Hydro Inc.	Fort Frances Power Corporation	Greater Sudbury Hydro Inc.	Grimsby Power Incorporated
Liquidity Ratios						
Current Ratio (Current Assets/Current Liabilities)	1.27	1.70	0.53	3.30	0.51	1.62
Leverage Ratios						
Debt Ratio (Long Term Financing/Total Assets)	29%	35%	0%	0%	0%	43%
Debt to Equity Ratio (Long Term Financing/Total Equity)	0.93	1.09	0.00	0.00	0.00	0.98
Interest Coverage (EBIT/Interest Charges)	0.72	3.51	3.07	0.68	1.13	2.11
Profitability Ratios						
Financial Statement Return on Assets (Net Income/Total Assets)	-0.56%	2.43%	3.66%	-0.84%	0.18%	2.69%
Financial Statement Return on Equity (Net Income/Total Equity)	-1.81%	7.46%	7.98%	-1.03%	1.09%	6.11%

Financial Ratios For the year ended December 31, 2009 (Alphabetically Listed)	Guelph Hydro Electric Systems Inc.	Haldimand County Hydro Inc.	Halton Hills Hydro Inc.	Hearst Power Distribution Company Limited	Horizon Utilities Corporation	Hydro 2000 Inc.
Liquidity Ratios						
Current Ratio (Current Assets/Current Liabilities)	0.97	0.85	1.31	4.56	0.39	1.99
Leverage Ratios						
Debt Ratio (Long Term Financing/Total Assets)	27%	8%	33%	30%	0%	17%
Debt to Equity Ratio (Long Term Financing/Total Equity)	0.67	0.13	0.76	0.59	0.00	0.29
Interest Coverage (EBIT/Interest Charges)	3.39	6.88	3.80	0.06	2.71	1.64
Profitability Ratios						
Financial Statement Return on Assets (Net Income/Total Assets)	3.01%	5.31%	3.68%	-2.68%	2.81%	1.16%
Financial Statement Return on Equity (Net Income/Total Equity)	7.49%	8.85%	8.40%	-5.30%	6.51%	1.99%

Financial Ratios For the year ended December 31, 2009 (Alphabetically Listed)	Hydro Hawkesbury Inc.	Hydro One Brampton Networks Inc.	Hydro One Networks Inc.	Hydro Ottawa Limited	Innisfil Hydro Distribution Systems Limited	Kenora Hydro Electric Corporation Ltd.
Liquidity Ratios						
Current Ratio (Current Assets/Current Liabilities)	2.62	0.85	0.94	1.25	0.61	2.05
Leverage Ratios						
Debt Ratio (Long Term Financing/Total Assets)	15%	45%	32%	44%	17%	39%
Debt to Equity Ratio (Long Term Financing/Total Equity)	0.36	1.34	1.31	1.22	0.29	0.77
Interest Coverage (EBIT/Interest Charges)	3.13	2.77	2.51	3.56	4.14	1.66
Profitability Ratios						
Financial Statement Return on Assets (Net Income/Total Assets)	2.70%	3.07%	2.18%	3.81%	4.55%	0.50%
Financial Statement Return on Equity (Net Income/Total Equity)	6.37%	9.05%	8.96%	10.70%	7.86%	0.99%

Financial Ratios **For the year ended December 31, 2009** **(Alphabetically Listed)**	Kingston Hydro Corporation	Kitchener-Wilmot Hydro Inc.	Lakefront Utilities Inc.	Lakeland Power Distribution Ltd.	London Hydro Inc.	Middlesex Power Distribution Corporation
Liquidity Ratios						
Current Ratio (Current Assets/Current Liabilities)	1.78	2.70	2.48	0.92	1.18	1.35
Leverage Ratios						
Debt Ratio (Long Term Financing/Total Assets)	29%	37%	44%	18%	28%	35%
Debt to Equity Ratio (Long Term Financing/Total Equity)	0.72	0.77	1.08	0.31	0.62	1.08
Interest Coverage (EBIT/Interest Charges)	3.71	2.56	2.87	4.23	3.74	2.70
Profitability Ratios						
Financial Statement Return on Assets (Net Income/Total Assets)	2.50%	2.23%	3.78%	1.76%	3.28%	3.31%
Financial Statement Return on Equity (Net Income/Total Equity)	6.23%	4.70%	9.36%	3.01%	7.39%	10.26%

Financial Ratios **For the year ended December 31, 2009** **(Alphabetically Listed)**	Midland Power Utility Corporation	Milton Hydro Distribution Inc.	Newmarket - Tay Power Distribution Ltd.	Niagara Peninsula Energy Inc.	Niagara-on-the-Lake Hydro Inc.	Norfolk Power Distribution Inc.
Liquidity Ratios						
Current Ratio (Current Assets/Current Liabilities)	0.57	1.25	3.56	1.60	0.67	1.24
Leverage Ratios						
Debt Ratio (Long Term Financing/Total Assets)	0%	26%	36%	26%	25%	40%
Debt to Equity Ratio (Long Term Financing/Total Equity)	0.00	0.53	0.70	0.48	0.54	0.94
Interest Coverage (EBIT/Interest Charges)	16.51	4.08	4.41	2.47	2.46	3.36
Profitability Ratios						
Financial Statement Return on Assets (Net Income/Total Assets)	5.84%	4.19%	4.94%	1.76%	2.81%	3.34%
Financial Statement Return on Equity (Net Income/Total Equity)	9.48%	8.73%	9.72%	3.22%	6.06%	7.88%

Financial Ratios For the year ended December 31, 2009 (Alphabetically Listed)	North Bay Hydro Distribution Limited	Northern Ontario Wires Inc.	Oakville Hydro Electricity Distribution Inc.	Orangeville Hydro Limited	Orillia Power Distribution Corporation	Oshawa PUC Networks Inc.
Liquidity Ratios						
Current Ratio (Current Assets/Current Liabilities)	2.57	1.99	1.09	1.67	1.54	3.66
Leverage Ratios						
Debt Ratio (Long Term Financing/Total Assets)	36%	32%	39%	29%	45%	35%
Debt to Equity Ratio (Long Term Financing/Total Equity)	0.87	0.75	1.41	0.66	1.19	0.96
Interest Coverage (EBIT/Interest Charges)	1.17	2.22	2.06	4.07	2.26	3.45
Profitability Ratios						
Financial Statement Return on Assets (Net Income/Total Assets)	0.16%	1.76%	1.96%	3.55%	2.24%	3.41%
Financial Statement Return on Equity (Net Income/Total Equity)	0.39%	4.08%	7.04%	8.11%	5.98%	9.34%

Financial Ratios For the year ended December 31, 2009 (Alphabetically Listed)	Ottawa River Power Corporation	Parry Sound Power Corporation	Peterborough Distribution Incorporated	Port Colborne Hydro Inc.	PowerStream Inc.	PUC Distribution Inc.
Liquidity Ratios						
Current Ratio (Current Assets/Current Liabilities)	3.69	1.13	1.82	0.20	0.97	1.38
Leverage Ratios						
Debt Ratio (Long Term Financing/Total Assets)	34%	32%	49%	0%	39%	44%
Debt to Equity Ratio (Long Term Financing/Total Equity)	0.74	0.95	1.39	0.00	1.33	1.34
Interest Coverage (EBIT/Interest Charges)	1.90	0.87	2.73	1.47	2.35	2.35
Profitability Ratios						
Financial Statement Return on Assets (Net Income/Total Assets)	2.16%	-0.48%	2.37%	0.78%	2.28%	3.03%
Financial Statement Return on Equity (Net Income/Total Equity)	4.67%	-1.42%	6.76%	-	7.85%	9.21%

Financial Ratios **For the year ended December 31, 2009** **(Alphabetically Listed)**	Renfrew Hydro Inc.	Rideau St. Lawrence Distribution Inc.	Sioux Lookout Hydro Inc.	St. Thomas Energy Inc.	Thunder Bay Hydro Electricity Distribution Inc.	Tillsonburg Hydro Inc.
Liquidity Ratios						
Current Ratio (Current Assets/Current Liabilities)	1.11	0.65	1.24	1.15	4.02	2.15
Leverage Ratios						
Debt Ratio (Long Term Financing/Total Assets)	3%	1%	34%	32%	45%	0%
Debt to Equity Ratio (Long Term Financing/Total Equity)	0.07	0.02	0.98	0.68	0.92	0.00
Interest Coverage (EBIT/Interest Charges)	1.15	4.32	2.97	3.22	5.57	13.74
Profitability Ratios						
Financial Statement Return on Assets (Net Income/Total Assets)	0.16%	2.88%	1.13%	3.20%	5.10%	1.60%
Financial Statement Return on Equity (Net Income/Total Equity)	0.40%	6.83%	3.24%	6.78%	10.43%	1.97%

Financial Ratios **For the year ended December 31, 2009** **(Alphabetically Listed)**	Toronto Hydro-Electric System Limited	Veridian Connections Inc.	Wasaga Distribution Inc.	Waterloo North Hydro Inc.	Welland Hydro-Electric System Corp.	Wellington North Power Inc.
Liquidity Ratios						
Current Ratio (Current Assets/Current Liabilities)	0.69	1.27	7.66	1.06	2.79	0.74
Leverage Ratios						
Debt Ratio (Long Term Financing/Total Assets)	27%	38%	27%	26%	43%	19%
Debt to Equity Ratio (Long Term Financing/Total Equity)	0.80	1.20	0.41	0.53	1.31	0.48
Interest Coverage (EBIT/Interest Charges)	1.99	3.21	5.72	3.17	1.80	6.33
Profitability Ratios						
Financial Statement Return on Assets (Net Income/Total Assets)	2.03%	3.14%	5.66%	3.83%	1.25%	7.76%
Financial Statement Return on Equity (Net Income/Total Equity)	6.15%	9.97%	8.36%	7.84%	3.83%	20.17%

Financial Ratios For the year ended December 31, 2009 (Alphabetically Listed)	West Coast Huron Energy Inc.	West Perth Power Inc.	Westario Power Inc.	Whitby Hydro Electric Corporation	Woodstock Hydro Services Inc.
Liquidity Ratios					
Current Ratio (Current Assets/Current Liabilities)	2.56	2.78	1.43	2.09	1.75
Leverage Ratios					
Debt Ratio (Long Term Financing/Total Assets)	16%	32%	28%	36%	35%
Debt to Equity Ratio (Long Term Financing/Total Equity)	0.24	0.68	0.56	0.69	0.77
Interest Coverage (EBIT/Interest Charges)	4.62	0.19	-32.75	2.80	2.73
Profitability Ratios					
Financial Statement Return on Assets (Net Income/Total Assets)	3.84%	-1.93%	3.99%	2.57%	1.90%
Financial Statement Return on Equity (Net Income/Total Equity)	5.84%	-4.09%	7.86%	4.91%	4.14%

General Statistics For the year ended December 31, 2009 (Alphabetically Listed)	Algoma Power Inc.	Atikokan Hydro Inc.	Bluewater Power Distribution Corporation	Brant County Power Inc.	Brantford Power Inc.	Burlington Hydro Inc.
Population Served	16,789	3,000	84,379	25,000	93,399	174,300
Municipal Population	10,552	3,000	86,689	30,000	93,399	174,300
Seasonal Population	3,643	0	0	0	0	0
Total Customers	11,688	1,670	35,580	9,614	37,668	63,558
Residential Customers	10,630	1,415	31,420	8,171	34,089	57,578
General Service <50kW Customers	1,010	225	3,505	1,286	2,721	4,974
General Service >50kW Customers	47	22	395	106	413	980
Large User (>5000kW) Customers	1	0	3	0	0	0
Scattered Unmetered Loads	0	8	257	51	445	26
Sub Transmission	0	0	0	0	0	0
Total Service Area (sq km)	14,200	380	201	258	74	188
Rural Service Area (sq km)	14,197	0	147	254	0	90
Urban Service Area (sq km)	3	380	54	4	74	98
Total km of Line	1,845	92	751	320	541	1,718
Overhead km of Line	1,841	92	574	282	266	1,064
Underground km of Line	4	0	177	38	275	654
Total kWh Sold (excluding losses)	186,826,563	23,072,734	1,004,963,419	271,571,601	907,514,251	1,584,518,052
Total Distribution Losses (kWh)	15,104,661	2,077,652	27,578,993	13,472,523	33,315,954	61,930,316
Total kWh Purchased	201,931,224	25,150,386	1,032,542,412	285,044,124	940,830,205	1,646,448,368
Winter Peak (kW)	41,137	5,065	148,400	44,355	152,415	267,776
Summer Peak (kW)	29,337	4,154	168,894	46,817	180,423	350,428
Average Peak (kW)	30,518	4,013	158,646	42,630	146,901	266,467
Capital Additions in 2009	$ 7,425,298	$ 183,820	$ 5,369,353	$ 1,617,575	$ 5,760,419	$ 18,080,893

General Statistics For the year ended December 31, 2009 (Alphabetically Listed)	Cambridge and North Dumfries Hydro Inc.	Canadian Niagara Power Inc.	Centre Wellington Hydro Ltd.	Chapleau Public Utilities Corporation	Chatham-Kent Hydro Inc.	Clinton Power Corporation
Population Served	137,350	27,698	20,500	2,428	94,769	3,100
Municipal Population	137,350	27,698	27,500	2,428	107,615	3,100
Seasonal Population	0	0	0	3	0	0
Total Customers	50,201	15,607	6,382	1,326	32,168	1,660
Residential Customers	44,805	14,248	5,603	1,144	28,463	1,411
General Service <50kW Customers	4,620	1,228	714	162	3,102	221
General Service >50kW Customers	709	131	63	14	410	17
Large User (>5000kW) Customers	2	0	0	0	1	0
Scattered Unmetered Loads	65	0	2	6	192	11
Sub Transmission	0	0	0	0	0	0
Total Service Area (sq km)	303	168	10	2	70	4
Rural Service Area (sq km)	213	133	0	0	0	0
Urban Service Area (sq km)	90	35	10	2	70	4
Total km of Line	1,105	522	146	27	810	21
Overhead km of Line	708	479	77	26	583	17
Underground km of Line	397	43	69	1	227	4
Total kWh Sold (excluding losses)	1,410,431,479	276,124,114	147,574,903	28,674,687	697,061,130	29,677,090
Total Distribution Losses (kWh)	40,404,107	21,928,098	6,715,456	1,242,500	29,266,381	1,625,740
Total kWh Purchased	1,450,835,586	298,052,212	154,290,359	29,917,187	726,327,511	31,302,830
Winter Peak (kW)	235,126	48,100	27,294	7,365	121,498	5,854
Summer Peak (kW)	286,911	56,000	26,103	4,724	145,023	5,269
Average Peak (kW)	232,785	45,200	24,370	4,678	117,115	5,073
Capital Additions in 2009	$ -	$ 4,304,187	$ 731,116	$ 8,255	$ 4,229,823	$ 141,600

General Statistics **For the year ended December 31, 2009** **(Alphabetically Listed)**	COLLUS Power Corporation	Cooperative Hydro Embrun Inc.	E.L.K. Energy Inc.	Eastern Ontario Power Inc.	Enersource Hydro Mississauga Inc.	EnWin Utilities Ltd.
Population Served	26,000	4,000	21,873	6,700	729,000	215,718
Municipal Population	26,000	12,500	74,185	5,000	729,000	216,473
Seasonal Population	0	0	0	200	0	0
Total Customers	14,908	1,941	11,112	3,560	189,738	84,726
Residential Customers	13,152	1,757	9,843	3,104	168,288	76,528
General Service <50kW Customers	1,609	172	1,148	422	16,800	6,981
General Service >50kW Customers	116	12	121	34	4,442	1,178
Large User (>5000kW) Customers	1	0	0	0	10	10
Scattered Unmetered Loads	30	0	0	0	198	29
Sub Transmission	0	0	0	0	0	0
Total Service Area (sq km)	57	5	22	66	287	120
Rural Service Area (sq km)	0	0	0	48	0	0
Urban Service Area (sq km)	57	5	22	18	287	120
Total km of Line	338	27	147	177	5,300	1,127
Overhead km of Line	213	15	89	167	1,834	713
Underground km of Line	125	12	58	10	3,466	414
Total kWh Sold (excluding losses)	306,783,697	29,476,112	233,193,994	60,765,742	7,498,987,529	2,463,049,038
Total Distribution Losses (kWh)	10,478,319	603,393	15,664,584	6,261,072	243,356,737	65,158,673
Total kWh Purchased	317,262,016	30,079,505	248,858,578	67,026,814	7,742,344,266	2,528,207,711
Winter Peak (kW)	59,168	6,862	45,013	13,097	1,188,400	399,800
Summer Peak (kW)	46,966	6,052	56,218	11,424	1,504,000	494,900
Average Peak (kW)	46,907	5,485	42,694	10,677	1,189,800	397,075
Capital Additions in 2009	$ 1,170,640	$ 99,261	$ 569,399	$ 887,747	$ 55,778,638	$ 17,255,362

General Statistics For the year ended December 31, 2009 (Alphabetically Listed)	Erie Thames Powerlines Corporation	Espanola Regional Hydro Distribution Corporation	Essex Powerlines Corporation	Festival Hydro Inc.	Fort Frances Power Corporation	Greater Sudbury Hydro Inc.
Population Served	32,042	7,138	73,654	43,941	8,315	109,529
Municipal Population	35,246	8,700	105,220	43,941	8,315	170,219
Seasonal Population	235	65	0	0	0	142
Total Customers	14,040	3,383	28,202	19,531	3,768	46,539
Residential Customers	12,550	2,857	25,817	17,311	3,296	41,926
General Service <50kW Customers	1,234	477	2,015	2,009	418	3,911
General Service >50kW Customers	146	25	222	209	47	512
Large User (>5000kW) Customers	2	0	0	2	0	0
Scattered Unmetered Loads	105	24	148	0	7	190
Sub Transmission	3	0	0	0	0	0
Total Service Area (sq km)	1,877	99	104	44	26	410
Rural Service Area (sq km)	1,830	73	38	0	0	120
Urban Service Area (sq km)	47	26	66	44	26	290
Total km of Line	270	137	458	276	84	944
Overhead km of Line	212	126	219	184	76	731
Underground km of Line	58	11	239	92	8	213
Total kWh Sold (excluding losses)	401,844,667	65,263,275	535,520,873	549,506,617	82,503,680	957,200,159
Total Distribution Losses (kWh)	18,083,010	1,650,791	21,342,063	17,502,094	3,643,000	55,715,400
Total kWh Purchased	419,927,677	66,914,066	556,862,936	567,008,711	86,146,680	1,012,915,559
Winter Peak (kW)	64,679	15,590	86,442	93,350	18,432	206,940
Summer Peak (kW)	77,494	9,617	122,372	99,720	12,143	154,643
Average Peak (kW)	61,376	10,783	83,563	89,305	13,622	157,619
Capital Additions in 2009	$ 1,794,153	$ 152,061	$ 2,843,643	$ 3,819,544	$ 261,955	$ 8,534,636

General Statistics **For the year ended December 31, 2009** **(Alphabetically Listed)**	Grimsby Power Incorporated	Guelph Hydro Electric Systems Inc.	Haldimand County Hydro Inc.	Halton Hills Hydro Inc.	Hearst Power Distribution Company Limited	Horizon Utilities Corporation
Population Served	23,935	120,977	45,212	55,289	5,635	572,925
Municipal Population	23,935	127,439	45,212	55,289	5,635	648,221
Seasonal Population	0	0	0	0	0	0
Total Customers	10,073	49,299	20,911	21,184	2,764	234,666
Residential Customers	9,222	45,023	18,309	18,924	2,332	212,580
General Service <50kW Customers	669	3,650	2,381	1,913	388	19,858
General Service >50kW Customers	101	582	137	207	44	2,216
Large User (>5000kW) Customers	0	4	0	0	0	12
Scattered Unmetered Loads	81	40	84	140	0	0
Sub Transmission	0	0	0	0	0	0
Total Service Area (sq km)	67	93	1,252	281	93	426
Rural Service Area (sq km)	45	0	1,216	256	0	88
Urban Service Area (sq km)	22	93	36	25	93	338
Total km of Line	172	1,063	1,731	1,363	68	3,363
Overhead km of Line	139	427	1,643	882	57	1,520
Underground km of Line	33	636	88	481	11	1,843
Total kWh Sold (excluding losses)	171,240,612	1,485,530,567	543,862,688	470,763,200	79,207,300	5,279,120,085
Total Distribution Losses (kWh)	4,582,985	18,658,228	20,559,742	29,213,200	2,196,659	169,117,916
Total kWh Purchased	175,823,596	1,504,188,795	564,422,430	499,976,400	81,403,959	5,448,238,001
Winter Peak (kW)	30,568	246,202	109,996	83,214	18,067	850,861
Summer Peak (kW)	40,871	267,576	114,709	97,839	12,737	1,008,981
Average Peak (kW)	30,154	233,718	93,326	80,504	13,330	817,224
Capital Additions in 2009	$ 1,359,103	$ 16,474,782	$ 4,888,068	$ 3,366,113	$ 520,049	$ 44,674,968

General Statistics For the year ended December 31, 2009 (Alphabetically Listed)	Hydro 2000 Inc.	Hydro Hawkesbury Inc.	Hydro One Brampton Networks Inc.	Hydro One Networks Inc.	Hydro Ottawa Limited	Innisfil Hydro Distribution Systems Limited
Population Served	2,630	10,500	480,000	2,994,456	817,560	34,000
Municipal Population	9,500	10,500	480,000	2,994,456	908,400	34,000
Seasonal Population	0	0	0	154,561	0	832
Total Customers	1,184	5,453	131,027	1,193,767	298,855	14,645
Residential Customers	1,027	4,781	121,692	1,084,186	269,288	13,636
General Service <50kW Customers	140	586	7,684	109,208	23,338	855
General Service >50kW Customers	11	81	1,645	0	3,370	72
Large User (>5000kW) Customers	0	1	6	0	11	0
Scattered Unmetered Loads	6	4	0	0	2,848	82
Sub Transmission	0	0	0	373	0	0
Total Service Area (sq km)	9	8	269	650,000	1,104	292
Rural Service Area (sq km)	0	0	0	650,000	650	229
Urban Service Area (sq km)	9	8	269	0	454	63
Total km of Line	21	66	2,778	120,750	5,387	741
Overhead km of Line	18	56	819	116,491	2,710	605
Underground km of Line	3	10	1,959	4,259	2,677	136
Total kWh Sold (excluding losses)	26,230,086	169,624,607	3,608,711,976	23,459,000,000	7,560,275,313	229,263,240
Total Distribution Losses (kWh)	677,066	10,030,019	115,478,783	1,747,000,000	224,447,888	11,390,113
Total kWh Purchased	26,907,152	179,654,626	3,724,190,759	25,206,000,000	7,784,723,201	240,653,353
Winter Peak (kW)	7,009	35,693	590,772	4,143,339	1,268,127	49,692
Summer Peak (kW)	4,814	28,593	737,026	2,928,200	1,363,575	42,327
Average Peak (kW)	4,512	28,720	585,586	2,945,626	1,169,307	41,970
Capital Additions in 2009	$ 109,286	$ 209,226	$ 32,880,858	$ 606,200,000	$ 52,507,794	$ 4,312,278

General Statistics For the year ended December 31, 2009 (Alphabetically Listed)	Kenora Hydro Electric Corporation Ltd.	Kingston Hydro Corporation	Kitchener-Wilmot Hydro Inc.	Lakefront Utilities Inc.	Lakeland Power Distribution Ltd.	London Hydro Inc.
Population Served	12,000	58,000	243,200	22,000	22,769	355,000
Municipal Population	16,500	119,000	243,200	22,000	36,889	355,000
Seasonal Population	0	0	0	0	192	0
Total Customers	5,579	26,991	85,998	9,534	9,387	146,787
Residential Customers	4,777	23,223	76,755	8,243	7,697	131,734
General Service <50kW Customers	733	3,255	7,425	1,065	1,547	11,914
General Service >50kW Customers	69	351	992	132	100	1,647
Large User (>5000kW) Customers	0	3	2	0	0	3
Scattered Unmetered Loads	0	159	824	94	43	1,489
Sub Transmission	0	0	0	0	0	0
Total Service Area (sq km)	24	32	404	27	144	421
Rural Service Area (sq km)	0	0	280	0	128	258
Urban Service Area (sq km)	24	32	124	27	16	163
Total km of Line	98	357	1,854	115	350	2,705
Overhead km of Line	88	233	1,035	95	285	1,323
Underground km of Line	10	124	819	20	65	1,382
Total kWh Sold (excluding losses)	108,849,700	714,181,728	1,777,333,175	247,365,480	213,656,605	3,150,821,438
Total Distribution Losses (kWh)	4,136,671	25,427,857	60,145,965	13,692,528	7,331,394	165,061,559
Total kWh Purchased	112,986,371	739,609,585	1,837,479,140	261,058,008	220,987,999	3,315,882,997
Winter Peak (kW)	22,360	134,412	309,396	44,396	44,128	535,154
Summer Peak (kW)	17,045	111,401	339,973	44,542	32,875	662,418
Average Peak (kW)	17,436	109,467	288,021	40,107	34,458	519,443
Capital Additions in 2009	$ 1,531,286	$ 3,641,040	$ 15,259,840	$ 1,210,827	$ 1,991,348	$ 26,511,233

General Statistics For the year ended December 31, 2009 (Alphabetically Listed)	Middlesex Power Distribution Corporation	Midland Power Utility Corporation	Milton Hydro Distribution Inc.	Newmarket - Tay Power Distribution Ltd.	Niagara Peninsula Energy Inc.	Niagara-on-the-Lake Hydro Inc.
Population Served	7,831	16,000	77,400	89,898	136,285	14,587
Municipal Population	21,749	17,000	77,400	136,438	137,189	14,587
Seasonal Population	0	0	0	525	0	250
Total Customers	7,911	6,905	27,506	32,827	50,823	7,880
Residential Customers	6,984	6,052	24,832	29,138	45,167	6,507
General Service <50kW Customers	780	729	2,203	2,893	4,389	1,230
General Service >50kW Customers	95	112	286	398	847	121
Large User (>5000kW) Customers	1	0	2	0	0	0
Scattered Unmetered Loads	51	12	183	398	420	22
Sub Transmission	0	0	0	0	0	0
Total Service Area (sq km)	26	20	370	74	827	133
Rural Service Area (sq km)	0	0	313	3	759	119
Urban Service Area (sq km)	26	20	57	71	68	14
Total km of Line	125	115	866	1,053	1,944	341
Overhead km of Line	99	79	546	585	1,475	246
Underground km of Line	26	36	320	468	469	95
Total kWh Sold (excluding losses)	184,693,861	203,110,374	677,368,948	700,600,681	1,171,202,445	173,476,091
Total Distribution Losses (kWh)	9,629,204	6,914,886	23,053,990	24,924,394	57,230,433	4,863,423
Total kWh Purchased	194,323,065	210,025,260	700,422,938	725,525,075	1,228,432,878	178,339,514
Winter Peak (kW)	33,090	37,116	118,179	122,972	193,622	28,303
Summer Peak (kW)	39,654	36,857	134,672	143,359	254,557	40,256
Average Peak (kW)	31,078	33,740	109,534	80,186	186,165	27,121
Capital Additions in 2009	$ 1,553,746	$ 2,281,088	$ 7,366,783	$ 5,920,779	$ 11,997,290	$ 2,505,182

General Statistics For the year ended December 31, 2009 (Alphabetically Listed)	Norfolk Power Distribution Inc.	North Bay Hydro Distribution Limited	Northern Ontario Wires Inc.	Oakville Hydro Electricity Distribution Inc.	Orangeville Hydro Limited	Orillia Power Distribution Corporation
Population Served	31,500	55,000	14,000	177,200	29,182	31,000
Municipal Population	63,000	55,000	18,777	177,200	29,182	31,000
Seasonal Population	200	0	0	0	0	0
Total Customers	18,895	23,776	6,069	62,858	11,126	12,962
Residential Customers	16,653	20,850	5,179	56,419	9,814	11,296
General Service <50kW Customers	2,071	2,629	798	4,887	1,148	1,359
General Service >50kW Customers	169	276	73	873	129	154
Large User (>5000kW) Customers	0	0	0	0	0	0
Scattered Unmetered Loads	2	21	19	679	35	153
Sub Transmission	0	0	0	0	0	0
Total Service Area (sq km)	693	330	28	143	17	27
Rural Service Area (sq km)	549	279	0	41	0	0
Urban Service Area (sq km)	144	51	28	102	17	27
Total km of Line	765	616	370	1,428	173	307
Overhead km of Line	657	517	365	551	102	248
Underground km of Line	108	99	5	877	71	59
Total kWh Sold (excluding losses)	363,133,912	552,881,331	123,574,677	1,471,673,901	243,157,027	309,605,840
Total Distribution Losses (kWh)	13,894,366	27,439,352	7,408,633	59,088,337	7,544,986	10,926,417
Total kWh Purchased	377,028,278	580,320,683	130,983,310	1,530,762,238	250,702,013	320,532,257
Winter Peak (kW)	82,592	119,797	24,291	254,560	43,705	59,109
Summer Peak (kW)	92,162	86,154	20,755	339,629	45,326	51,144
Average Peak (kW)	69,751	89,645	20,040	253,016	39,984	47,700
Capital Additions in 2009	$ 9,599,769	$ 7,318,513	$ 247,069	$ 19,045,133	$ 1,783,450	$ 1,617,709

General Statistics For the year ended December 31, 2009 (Alphabetically Listed)	Oshawa PUC Networks Inc.	Ottawa River Power Corporation	Parry Sound Power Corporation	Peterborough Distribution Incorporated	Port Colborne Hydro Inc.	PowerStream Inc.
Population Served	155,000	20,200	6,500	81,937	18,003	1,030,369
Municipal Population	155,000	20,200	6,500	81,937	18,003	1,030,369
Seasonal Population	0	0	0	0	0	0
Total Customers	52,488	10,462	3,378	35,037	9,124	320,695
Residential Customers	47,769	8,851	2,751	30,680	8,170	283,665
General Service <50kW Customers	3,897	1,394	540	3,609	874	29,594
General Service >50kW Customers	517	144	68	363	80	4,654
Large User (>5000kW) Customers	1	0	0	2	0	1
Scattered Unmetered Loads	304	73	19	383	0	2,781
Sub Transmission	0	0	0	0	0	0
Total Service Area (sq km)	149	35	15	64	122	806
Rural Service Area (sq km)	78	0	0	0	102	303
Urban Service Area (sq km)	71	35	15	64	20	503
Total km of Line	950	146	128	550	313	7,681
Overhead km of Line	511	127	117	384	297	2,755
Underground km of Line	439	19	11	166	16	4,926
Total kWh Sold (excluding losses)	1,087,954,743	191,997,485	89,931,923	791,578,450	190,210,933	8,039,883,040
Total Distribution Losses (kWh)	36,867,536	7,362,456	2,831,655	42,470,933	4,039,850	253,031,546
Total kWh Purchased	1,124,822,279	199,359,940	92,763,578	834,049,383	194,250,783	8,292,914,586
Winter Peak (kW)	208,345	36,925	20,600	153,787	36,100	1,336,784
Summer Peak (kW)	210,068	29,961	12,820	147,235	39,700	1,762,834
Average Peak (kW)	180,645	28,499	14,548	131,446	32,400	1,354,508
Capital Additions in 2009	$ 6,350,924	$ 1,128,076	$ 491,418	$ 6,804,755	$ 2,906,930	$ 63,314,708

General Statistics For the year ended December 31, 2009 (Alphabetically Listed)	PUC Distribution Inc.	Renfrew Hydro Inc.	Rideau St. Lawrence Distribution Inc.	Sioux Lookout Hydro Inc.	St. Thomas Energy Inc.	Thunder Bay Hydro Electricity Distribution Inc.
Population Served	78,000	7,846	9,900	5,336	36,000	110,046
Municipal Population	75,000	7,846	16,700	5,336	36,000	109,141
Seasonal Population	100	0	0	108	0	0
Total Customers	32,825	4,180	5,863	2,740	16,243	49,922
Residential Customers	29,028	3,613	4,974	2,296	14,374	44,443
General Service <50kW Customers	3,341	503	774	392	1,672	4,486
General Service >50kW Customers	439	64	66	39	192	524
Large User (>5000kW) Customers	0	0	0	0	0	0
Scattered Unmetered Loads	17	0	49	13	5	469
Sub Transmission	0	0	0	0	0	0
Total Service Area (sq km)	342	13	18	536	33	381
Rural Service Area (sq km)	284	0	7	530	0	259
Urban Service Area (sq km)	58	13	11	6	33	122
Total km of Line	732	55	89	211	243	1,186
Overhead km of Line	616	53	80	205	156	952
Underground km of Line	116	2	9	6	87	234
Total kWh Sold (excluding losses)	707,756,700	96,981,360	110,633,517	71,778,509	289,185,003	974,297,469
Total Distribution Losses (kWh)	25,113,286	4,985,905	7,781,309	4,238,120	11,794,643	37,910,835
Total kWh Purchased	732,869,986	101,967,265	118,414,826	76,016,629	300,979,646	1,012,208,304
Winter Peak (kW)	147,108	19,807	26,268	18,326	52,131	186,606
Summer Peak (kW)	97,507	18,505	18,378	11,160	61,895	153,937
Average Peak (kW)	111,107	16,671	19,194	12,426	34,341	154,002
Capital Additions in 2009	$ 5,856,346	$ 633,656	$ 543,810	$ 387,978	$ 1,266,180	$ 8,516,762

General Statistics For the year ended December 31, 2009 (Alphabetically Listed)	Tillsonburg Hydro Inc.	Toronto Hydro-Electric System Limited	Veridian Connections Inc.	Wasaga Distribution Inc.	Waterloo North Hydro Inc.	Welland Hydro-Electric System Corp.
Population Served	15,140	2,503,281	308,114	17,300	154,370	50,331
Municipal Population	15,000	2,503,281	419,985	17,300	154,370	50,331
Seasonal Population	0	0	1,601	1,200	0	0
Total Customers	6,738	690,243	111,994	11,869	51,089	21,916
Residential Customers	5,907	611,357	101,547	11,010	45,113	19,803
General Service <50kW Customers	675	64,781	8,501	801	5,300	1,725
General Service >50kW Customers	87	12,953	1,049	33	661	172
Large User (>5000kW) Customers	0	47	4	0	1	2
Scattered Unmetered Loads	69	1,105	893	25	14	214
Sub Transmission	0	0	0	0	0	0
Total Service Area (sq km)	24	630	639	61	672	86
Rural Service Area (sq km)	3	0	386	8	607	0
Urban Service Area (sq km)	21	630	253	53	65	86
Total km of Line	156	9,794	2,201	236	1,541	443
Overhead km of Line	102	4,153	1,280	125	1,059	330
Underground km of Line	54	5,641	921	111	482	113
Total kWh Sold (excluding losses)	184,230,659	24,588,094,033	2,473,069,287	117,509,098	1,360,024,644	402,158,613
Total Distribution Losses (kWh)	9,399,202	961,179,992	95,395,026	6,291,175	51,743,018	17,458,601
Total kWh Purchased	193,629,861	25,549,274,025	2,568,464,313	123,800,273	1,411,767,662	419,617,214
Winter Peak (kW)	36,361	4,108,656	433,843	24,315	233,874	78,842
Summer Peak (kW)	41,632	4,607,346	488,365	26,445	259,232	85,983
Average Peak (kW)	35,707	3,489,158	397,920	20,639	223,335	71,014
Capital Additions in 2009	$ 1,020,825	$ 261,125,162	$ 30,741,373	$ 2,086,187	$ 17,408,533	$ 2,015,222

General Statistics For the year ended December 31, 2009 (Alphabetically Listed)	Wellington North Power Inc.	West Coast Huron Energy Inc.	West Perth Power Inc.	Westario Power Inc.	Whitby Hydro Electric Corporation	Woodstock Hydro Services Inc.
Population Served	7,200	7,251	3,900	47,229	121,300	35,000
Municipal Population	11,500	7,251	9,000	77,847	121,300	36,000
Seasonal Population	0	0	0	0	0	0
Total Customers	3,588	3,763	2,052	21,805	39,513	14,838
Residential Customers	3,056	3,231	1,786	19,033	36,762	13,429
General Service <50kW Customers	480	474	241	2,435	1,926	1,170
General Service >50kW Customers	49	53	20	276	435	200
Large User (>5000kW) Customers	0	1	0	0	0	0
Scattered Unmetered Loads	3	4	5	61	390	39
Sub Transmission	0	0	0	0	0	0
Total Service Area (sq km)	14	8	6	49	148	29
Rural Service Area (sq km)	0	0	0	0	81	0
Urban Service Area (sq km)	14	8	6	49	67	29
Total km of Line	76	65	36	436	1,034	245
Overhead km of Line	66	52	25	310	495	154
Underground km of Line	10	13	11	126	539	91
Total kWh Sold (excluding losses)	87,132,499	155,318,971	58,761,308	475,053,893	840,203,822	354,090,474
Total Distribution Losses (kWh)	6,282,883	4,828,623	708,739	7,304,204	36,756,131	14,608,999
Total kWh Purchased	93,415,382	160,147,594	59,470,047	482,358,097	876,959,953	368,699,473
Winter Peak (kW)	16,602	26,342	10,098	80,151	147,709	62,219
Summer Peak (kW)	14,640	26,561	10,187	60,590	184,500	72,543
Average Peak (kW)	14,642	25,149	9,482	63,047	142,909	59,078
Capital Additions in 2009	$ 414,054	$ 913,116	$ 570,322	$ 3,329,535	$ 5,524,972	$ 4,117,714

Unitized Statistics For the year ended December 31, 2009 (Alphabetically Listed)	Algoma Power Inc.	Atikokan Hydro Inc.	Bluewater Power Distribution Corporation	Brant County Power Inc.	Brantford Power Inc.	Burlington Hydro Inc.
# of Customers per sq km of Service Area	0.82	4.39	177.01	37.26	509.03	338.07
# of Customers per km of Line	6.33	18.15	47.38	30.04	69.63	37.00
Average Revenue from Distribution						
Per Customer annually	$ 1,500.85	$ 781.35	$ 529.79	$ 628.83	$ 416.90	$ 437.83
Per Total kWh Purchased	$ 0.087	$ 0.052	$ 0.018	$ 0.021	$ 0.017	$ 0.017
Average Cost of Power						
Per Customer annually	$ 1,252	$ 1,092	$ 1,511	$ 1,631	$ 1,912	$ 1,578
Per Total kWh Purchased	$ 0.072	$ 0.073	$ 0.052	$ 0.055	$ 0.077	$ 0.061
Avg monthly kWh consumed per customer	1,440	1,255	2,418	2,471	2,081	2,159
Avg Peak (kW) per Customer	2.61	2.40	4.46	4.43	3.90	4.19
OM&A Per Customer	$ 737.15	$ 521.39	$ 285.13	$ 379.86	$ 205.16	$ 207.76
Net Income (Loss) Per Customer	$ (833.93)	$ 103.78	$ 79.24	$ 77.77	$ 58.91	$ 63.14
Net Fixed Assets per Customer	$ 5,385	$ 1,232	$ 1,091	$ 1,992	$ 1,592	$ 1,330
SERVICE QUALITY INDICATORS						
Low Voltage Connections	100.00	-	100.00	100.00	99.60	97.20
High Voltage Connections	-	-	100.00	-	-	-
Telephone Accessibility	72.10	100.00	67.40	91.80	75.90	72.80
Appointments Met	98.90	100.00	100.00	100.00	100.00	97.60
Written Response to Enquires	100.00	100.00	100.00	100.00	99.70	100.00
Emergency Urban Response	-	100.00	100.00	-	100.00	89.50
Emergency Rural Response	-	-	100.00	100.00	-	-
Telephone Call Abandon Rate	-	-	10.70	-	2.60	3.30
Appointment Scheduling	97.60	100.00	95.30	100.00	100.00	100.00
Rescheduling a Missed Appointment	100.00	-	100.00	-	97.60	100.00
Service Reliability Indices						
SAIDI-Annual	9.86	1.45	2.09	1.42	0.99	1.08
SAIFI-Annual	3.42	1.99	2.76	1.15	1.39	1.17
CAIDI-Annual	2.88	0.73	0.76	1.24	0.71	0.92

Unitized Statistics **For the year ended December 31, 2009** **(Alphabetically Listed)**	Cambridge and North Dumfries Hydro Inc.	Canadian Niagara Power Inc.	Centre Wellington Hydro Ltd.	Chapleau Public Utilities Corporation	Chatham-Kent Hydro Inc.	Clinton Power Corporation
# of Customers per sq km of Service Area	165.68	92.90	638.20	663.00	459.54	415.00
# of Customers per km of Line	45.43	29.90	43.71	49.11	39.71	79.05
Average Revenue from Distribution						
Per Customer annually	$ 419.88	$ 702.56	$ 439.59	$ 508.36	$ 420.75	$ 394.21
Per Total kWh Purchased	$ 0.015	$ 0.037	$ 0.018	$ 0.023	$ 0.019	$ 0.021
Average Cost of Power						
Per Customer annually	$ 2,091	$ 1,684	$ 1,525	$ 1,641	$ 1,737	$ 1,225
Per Total kWh Purchased	$ 0.072	$ 0.088	$ 0.063	$ 0.073	$ 0.077	$ 0.065
Avg monthly kWh consumed per customer	2,408	1,591	2,015	1,880	1,882	1,571
Avg Peak (kW) per Customer	4.64	2.90	3.82	3.53	3.64	3.06
OM&A Per Customer	$ 197.44	$ 302.63	$ 262.96	$ 370.21	$ 172.53	$ 332.05
Net Income (Loss) Per Customer	$ 53.57	$ 99.75	$ 37.28	$ 106.92	$ 65.36	$ 0.85
Net Fixed Assets per Customer	$ 1,669	$ 3,190	$ 1,052	$ 639	$ 1,448	$ 755
SERVICE QUALITY INDICATORS						
Low Voltage Connections	99.20	86.70	99.00	100.00	97.80	100.00
High Voltage Connections	-	-	-	-	-	100.00
Telephone Accessibility	77.40	83.80	99.50	100.00	74.10	96.00
Appointments Met	100.00	97.70	100.00	100.00	98.50	100.00
Written Response to Enquires	99.20	100.00	100.00	100.00	100.00	100.00
Emergency Urban Response	98.00	100.00	100.00	-	91.40	-
Emergency Rural Response	92.50	100.00	-	-	-	-
Telephone Call Abandon Rate	8.10	2.40	0.50	-	-	4.50
Appointment Scheduling	100.00	99.10	100.00	100.00	100.00	100.00
Rescheduling a Missed Appointment	-	100.00	-	-	-	-
Service Reliability Indices						
SAIDI-Annual	0.52	5.67	1.29	8.22	1.68	0.34
SAIFI-Annual	0.98	3.45	0.88	2.16	1.38	1.99
CAIDI-Annual	0.53	1.64	1.48	3.80	1.22	0.17

Unitized Statistics For the year ended December 31, 2009 (Alphabetically Listed)	COLLUS Power Corporation	Cooperative Hydro Embrun Inc.	E.L.K. Energy Inc.	Eastern Ontario Power Inc.	Enersource Hydro Mississauga Inc.	EnWin Utilities Ltd.
# of Customers per sq km of Service Area	261.54	388.20	505.09	53.94	661.11	706.05
# of Customers per km of Line	44.11	71.89	75.59	20.11	35.80	75.18
Average Revenue from Distribution						
Per Customer annually	$ 365.87	$ 311.48	$ 415.95	-	$ 620.01	$ 570.68
Per Total kWh Purchased	$ 0.017	$ 0.020	$ 0.019	-	$ 0.015	$ 0.019
Average Cost of Power						
Per Customer annually	$ 1,614	$ 747	$ 1,298	-	$ 3,047	$ 1,900
Per Total kWh Purchased	$ 0.076	$ 0.048	$ 0.058	-	$ 0.075	$ 0.064
Avg monthly kWh consumed per customer	1,773	1,291	1,866	1,569	3,400	2,487
Avg Peak (kW) per Customer	3.15	2.83	3.84	3.00	6.27	4.69
OM&A Per Customer	$ 262.60	$ 210.72	$ 224.82	-	$ 263.63	$ 235.45
Net Income (Loss) Per Customer	$ 30.10	$ 43.10	$ 88.50	-	$ 97.65	$ 120.62
Net Fixed Assets per Customer	$ 841	$ 986	$ 767	-	$ 2,370	$ 2,123
SERVICE QUALITY INDICATORS						
Low Voltage Connections	100.00	100.00	99.00	100.00	97.90	99.00
High Voltage Connections	100.00	-	-	-	100.00	-
Telephone Accessibility	98.00	92.30	95.90	90.30	81.40	75.70
Appointments Met	100.00	100.00	93.10	100.00	98.00	97.20
Written Response to Enquires	100.00	100.00	82.10	100.00	99.50	100.00
Emergency Urban Response	100.00	100.00	95.80	100.00	96.20	97.70
Emergency Rural Response	-	-	-	-	-	-
Telephone Call Abandon Rate	-	7.70	-	1.90	2.90	2.80
Appointment Scheduling	100.00	100.00	99.20	99.60	100.00	99.00
Rescheduling a Missed Appointment	-	-	-	-	-	100.00
Service Reliability Indices						
SAIDI-Annual	1.87	0.01	0.64	6.94	0.61	0.55
SAIFI-Annual	1.75	0.16	0.17	4.22	1.16	1.18
CAIDI-Annual	1.07	0.04	3.85	1.65	0.53	0.47

Unitized Statistics For the year ended December 31, 2009 (Alphabetically Listed)	Erie Thames Powerlines Corporation	Espanola Regional Hydro Distribution Corporation	Essex Powerlines Corporation	Festival Hydro Inc.	Fort Frances Power Corporation	Greater Sudbury Hydro Inc.
# of Customers per sq km of Service Area	7.48	34.17	271.17	443.89	144.92	113.51
# of Customers per km of Line	52.00	24.69	61.58	70.76	44.86	49.30
Average Revenue from Distribution						
Per Customer annually	$ 428.74	$ 400.06	$ 356.28	$ 488.11	$ 411.73	$ 486.45
Per Total kWh Purchased	$ 0.014	$ 0.020	$ 0.018	$ 0.017	$ 0.018	$ 0.022
Average Cost of Power						
Per Customer annually	$ 2,189	$ 1,364	$ 1,547	$ 2,237	$ 1,674	$ 1,658
Per Total kWh Purchased	$ 0.073	$ 0.069	$ 0.078	$ 0.077	$ 0.073	$ 0.076
Avg monthly kWh consumed per customer	2,492	1,648	1,645	2,419	1,905	1,814
Avg Peak (kW) per Customer	4.37	3.19	2.96	4.57	3.62	3.39
OM&A Per Customer	$ 308.71	$ 327.70	$ 184.00	$ 187.14	$ 349.41	$ 245.70
Net Income (Loss) Per Customer	$ 9.19	$ (8.75)	$ 47.93	$ 75.60	$ (15.30)	$ 3.62
Net Fixed Assets per Customer	$ 1,306	$ 608	$ 1,134	$ 1,675	$ 772	$ 1,385
SERVICE QUALITY INDICATORS						
Low Voltage Connections	88.80	100.00	98.80	100.00	100.00	100.00
High Voltage Connections	-	-	-	-	100.00	-
Telephone Accessibility	96.00	63.70	83.60	98.30	97.40	78.70
Appointments Met	100.00	-	93.50	100.00	100.00	100.00
Written Response to Enquires	98.00	-	89.60	99.00	100.00	100.00
Emergency Urban Response	100.00	100.00	100.00	100.00	100.00	98.20
Emergency Rural Response	-	-	-	-	-	-
Telephone Call Abandon Rate	3.50	7.60	5.60	4.70	3.10	2.40
Appointment Scheduling	100.00	93.70	98.30	99.40	100.00	100.00
Rescheduling a Missed Appointment	-	-	100.00	100.00	-	-
Service Reliability Indices						
SAIDI-Annual	1.91	1.57	3.16	1.74	6.63	1.45
SAIFI-Annual	0.62	1.10	2.16	1.99	2.40	1.47
CAIDI-Annual	3.09	1.43	1.46	0.87	2.76	0.99

Unitized Statistics For the year ended December 31, 2009 (Alphabetically Listed)	Grimsby Power Incorporated	Guelph Hydro Electric Systems Inc.	Haldimand County Hydro Inc.	Halton Hills Hydro Inc.	Hearst Power Distribution Company Limited	Horizon Utilities Corporation
# of Customers per sq km of Service Area	150.34	530.10	16.70	75.39	29.72	550.86
# of Customers per km of Line	58.56	46.38	12.08	15.54	40.65	69.78
Average Revenue from Distribution						
Per Customer annually	$ 350.18	$ 490.73	$ 663.80	$ 454.99	$ 330.15	$ 378.28
Per Total kWh Purchased	$ 0.020	$ 0.016	$ 0.025	$ 0.019	$ 0.011	$ 0.016
Average Cost of Power						
Per Customer annually	$ 1,334	$ 1,964	$ 1,587	$ 1,704	$ 2,130	$ 1,545
Per Total kWh Purchased	$ 0.076	$ 0.064	$ 0.059	$ 0.072	$ 0.072	$ 0.067
Avg monthly kWh consumed per customer	1,455	2,543	2,249	1,967	2,454	1,935
Avg Peak (kW) per Customer	2.99	4.74	4.46	3.80	4.82	3.48
OM&A Per Customer	$ 172.75	$ 194.07	$ 332.30	$ 209.03	$ 306.37	$ 165.25
Net Income (Loss) Per Customer	$ 35.73	$ 67.87	$ 129.21	$ 83.91	$ (55.16)	$ 48.80
Net Fixed Assets per Customer	$ 1,132	$ 1,838	$ 1,642	$ 1,404	$ 312	$ 1,374
SERVICE QUALITY INDICATORS						
Low Voltage Connections	100.00	100.00	96.70	100.00	100.00	99.80
High Voltage Connections	-	100.00	100.00	-	-	-
Telephone Accessibility	71.00	70.60	80.40	85.60	95.30	81.60
Appointments Met	99.40	96.50	98.70	99.70	100.00	96.30
Written Response to Enquires	100.00	100.00	95.00	99.40	100.00	98.90
Emergency Urban Response	100.00	90.20	100.00	100.00	-	99.20
Emergency Rural Response	100.00	-	93.80	100.00	-	-
Telephone Call Abandon Rate	2.50	-	3.30	3.00	-	-
Appointment Scheduling	100.00	100.00	100.00	100.00	100.00	99.50
Rescheduling a Missed Appointment	-	100.00	92.30	100.00	-	-
Service Reliability Indices						
SAIDI-Annual	0.38	0.68	4.30	2.00	37.50	1.18
SAIFI-Annual	0.27	1.56	1.58	1.48	11.19	1.81
CAIDI-Annual	1.41	0.43	2.72	1.35	3.35	0.65

Unitized Statistics For the year ended December 31, 2009 (Alphabetically Listed)	Hydro 2000 Inc.	Hydro Hawkesbury Inc.	Hydro One Brampton Networks Inc.	Hydro One Networks Inc.	Hydro Ottawa Limited	Innisfil Hydro Distribution Systems Limited
# of Customers per sq km of Service Area	131.56	681.63	487.09	1.84	270.70	50.15
# of Customers per km of Line	56.38	82.62	47.17	9.89	55.48	19.76
Average Revenue from Distribution						
Per Customer annually	$ 291.51	$ 224.23	$ 473.03	$ 885.70	$ 489.53	$ 525.41
Per Total kWh Purchased	$ 0.013	$ 0.007	$ 0.017	$ 0.042	$ 0.019	$ 0.032
Average Cost of Power						
Per Customer annually	$ 1,765	$ 1,953	$ 2,179	$ 1,709	$ 1,967	$ 1,289
Per Total kWh Purchased	$ 0.078	$ 0.059	$ 0.077	$ 0.081	$ 0.076	$ 0.078
Avg monthly kWh consumed per customer	1,894	2,746	2,369	1,760	2,171	1,369
Avg Peak (kW) per Customer	3.81	5.27	4.47	2.47	3.91	2.87
OM&A Per Customer	$ 226.57	$ 144.50	$ 134.21	$ 423.91	$ 173.90	$ 254.06
Net Income (Loss) Per Customer	$ 12.31	$ 30.87	$ 74.01	$ 134.35	$ 86.93	$ 82.47
Net Fixed Assets per Customer	$ 371	$ 360	$ 1,866	$ 3,771	$ 1,715	$ 1,346
SERVICE QUALITY INDICATORS						
Low Voltage Connections	100.00	100.00	100.00	90.50	98.70	94.40
High Voltage Connections	-	100.00	100.00	91.30	100.00	-
Telephone Accessibility	99.60	99.90	82.30	69.70	69.00	100.00
Appointments Met	100.00	100.00	100.00	93.50	99.30	82.40
Written Response to Enquires	100.00	100.00	100.00	99.00	99.80	100.00
Emergency Urban Response	100.00	100.00	98.50	-	95.30	-
Emergency Rural Response	-	-	-	81.00	-	100.00
Telephone Call Abandon Rate	0.40	-	1.40	4.20	5.80	-
Appointment Scheduling	100.00	100.00	99.90	93.10	100.00	100.00
Rescheduling a Missed Appointment	-	-	100.00	96.80	100.00	100.00
Service Reliability Indices						
SAIDI-Annual	10.00	2.80	0.79	9.95	1.50	1.40
SAIFI-Annual	2.56	3.09	1.27	3.57	1.15	1.41
CAIDI-Annual	3.90	0.91	0.62	2.79	1.30	0.99

Unitized Statistics For the year ended December 31, 2009 (Alphabetically Listed)	Kenora Hydro Electric Corporation Ltd.	Kingston Hydro Corporation	Kitchener-Wilmot Hydro Inc.	Lakefront Utilities Inc.	Lakeland Power Distribution Ltd.	London Hydro Inc.
# of Customers per sq km of Service Area	232.46	843.47	212.87	353.11	65.19	348.66
# of Customers per km of Line	56.93	75.61	46.39	82.90	26.82	54.27
Average Revenue from Distribution						
Per Customer annually	$ 391.43	$ 384.06	$ 386.60	$ 458.97	$ 486.90	$ 388.92
Per Total kWh Purchased	$ 0.019	$ 0.014	$ 0.018	$ 0.017	$ 0.021	$ 0.017
Average Cost of Power						
Per Customer annually	$ 1,413	$ 1,999	$ 1,664	$ 2,054	$ 1,739	$ 1,714
Per Total kWh Purchased	$ 0.070	$ 0.073	$ 0.078	$ 0.075	$ 0.074	$ 0.076
Avg monthly kWh consumed per customer	1,688	2,284	1,781	2,282	1,962	1,882
Avg Peak (kW) per Customer	3.13	4.06	3.35	4.21	3.67	3.54
OM&A Per Customer	$ 305.00	$ 196.98	$ 141.90	$ 194.59	$ 300.90	$ 187.87
Net Income (Loss) Per Customer	$ 9.22	$ 43.17	$ 54.26	$ 78.84	$ 35.54	$ 56.72
Net Fixed Assets per Customer	$ 1,229	$ 1,027	$ 1,638	$ 1,138	$ 1,391	$ 1,307
SERVICE QUALITY INDICATORS						
Low Voltage Connections	100.00	100.00	93.50	100.00	89.40	99.90
High Voltage Connections	-	-	100.00	100.00	100.00	100.00
Telephone Accessibility	89.10	67.10	78.00	100.00	81.20	56.30
Appointments Met	100.00	99.30	98.40	100.00	98.90	99.50
Written Response to Enquires	100.00	100.00	99.20	100.00	99.10	100.00
Emergency Urban Response	100.00	97.60	97.90	97.80	100.00	95.20
Emergency Rural Response	-	-	100.00	-	100.00	-
Telephone Call Abandon Rate	-	3.90	2.30	-	3.50	17.10
Appointment Scheduling	100.00	95.70	99.90	100.00	98.30	97.90
Rescheduling a Missed Appointment	-	100.00	98.00	-	100.00	100.00
Service Reliability Indices						
SAIDI-Annual	1.65	3.54	1.42	1.47	3.40	0.89
SAIFI-Annual	1.60	2.58	3.00	1.15	1.40	1.59
CAIDI-Annual	1.03	1.37	0.47	1.27	2.43	0.56

Unitized Statistics For the year ended December 31, 2009 (Alphabetically Listed)	Middlesex Power Distribution Corporation	Midland Power Utility Corporation	Milton Hydro Distribution Inc.	Newmarket - Tay Power Distribution Ltd.	Niagara Peninsula Energy Inc.	Niagara-on-the-Lake Hydro Inc.
# of Customers per sq km of Service Area	304.27	345.25	74.34	443.61	61.45	59.25
# of Customers per km of Line	63.29	60.04	31.76	31.17	26.14	23.11
Average Revenue from Distribution						
Per Customer annually	$ 397.02	$ 481.22	$ 442.05	$ 473.95	$ 541.54	$ 593.94
Per Total kWh Purchased	$ 0.016	$ 0.016	$ 0.017	$ 0.021	$ 0.022	$ 0.026
Average Cost of Power						
Per Customer annually	$ 1,913	$ 2,403	$ 1,916	$ 1,661	$ 1,883	$ 1,606
Per Total kWh Purchased	$ 0.078	$ 0.079	$ 0.075	$ 0.075	$ 0.078	$ 0.071
Avg monthly kWh consumed per customer	2,047	2,535	2,122	1,842	2,014	1,886
Avg Peak (kW) per Customer	3.93	4.89	3.98	2.44	3.66	3.44
OM&A Per Customer	$ 206.64	$ 259.03	$ 195.08	$ 199.39	$ 256.67	$ 230.70
Net Income (Loss) Per Customer	$ 63.70	$ 120.47	$ 88.65	$ 100.60	$ 49.13	$ 89.11
Net Fixed Assets per Customer	$ 1,073	$ 1,355	$ 1,560	$ 1,522	$ 2,249	$ 2,544
SERVICE QUALITY INDICATORS						
Low Voltage Connections	100.00	100.00	93.60	99.40	87.90	100.00
High Voltage Connections	-	-	-	-	90.00	100.00
Telephone Accessibility	-	99.90	70.00	89.30	61.00	89.10
Appointments Met	100.00	100.00	100.00	100.00	100.00	100.00
Written Response to Enquires	100.00	90.60	99.70	100.00	99.80	100.00
Emergency Urban Response	94.00	100.00	100.00	100.00	100.00	100.00
Emergency Rural Response	-	-	100.00	-	92.90	100.00
Telephone Call Abandon Rate	-	-	2.40	1.60	3.60	0.30
Appointment Scheduling	-	-	100.00	100.00	100.00	100.00
Rescheduling a Missed Appointment	-	-	-	-	-	-
Service Reliability Indices						
SAIDI-Annual	2.10	3.07	1.15	0.40	-	0.33
SAIFI-Annual	0.92	0.85	1.23	0.30	-	0.28
CAIDI-Annual	2.28	3.62	0.94	1.34	-	1.20

Unitized Statistics For the year ended December 31, 2009 (Alphabetically Listed)	Norfolk Power Distribution Inc.	North Bay Hydro Distribution Limited	Northern Ontario Wires Inc.	Oakville Hydro Electricity Distribution Inc.	Orangeville Hydro Limited	Orillia Power Distribution Corporation
# of Customers per sq km of Service Area	27.27	72.05	216.75	439.57	654.47	480.07
# of Customers per km of Line	24.70	38.60	16.40	44.02	64.31	42.22
Average Revenue from Distribution						
Per Customer annually	$ 600.98	$ 441.27	$ 427.39	$ 465.36	$ 419.96	$ 529.40
Per Total kWh Purchased	$ 0.030	$ 0.018	$ 0.020	$ 0.019	$ 0.019	$ 0.021
Average Cost of Power						
Per Customer annually	$ 1,522	$ 1,718	$ 1,588	$ 1,662	$ 1,704	$ 1,777
Per Total kWh Purchased	$ 0.076	$ 0.070	$ 0.074	$ 0.068	$ 0.076	$ 0.072
Avg monthly kWh consumed per customer	1,663	2,034	1,799	2,029	1,878	2,061
Avg Peak (kW) per Customer	3.69	3.77	3.30	4.03	3.59	3.68
OM&A Per Customer	$ 239.85	$ 208.44	$ 333.47	$ 162.65	$ 213.62	$ 302.07
Net Income (Loss) Per Customer	$ 110.51	$ 4.06	$ 21.76	$ 44.06	$ 64.51	$ 42.08
Net Fixed Assets per Customer	$ 2,577	$ 1,444	$ 594	$ 1,766	$ 1,230	$ 1,217
SERVICE QUALITY INDICATORS						
Low Voltage Connections	98.60	100.00	100.00	97.20	100.00	100.00
High Voltage Connections	-	100.00	100.00	-	100.00	-
Telephone Accessibility	87.60	52.60	100.00	74.70	100.00	98.70
Appointments Met	99.30	100.00	100.00	99.90	100.00	100.00
Written Response to Enquires	87.00	100.00	-	99.00	100.00	100.00
Emergency Urban Response	100.00	100.00	100.00	-	100.00	100.00
Emergency Rural Response	95.50	100.00	-	-	-	-
Telephone Call Abandon Rate	4.40	9.30	-	5.30	-	-
Appointment Scheduling	95.70	100.00	-	100.00	100.00	100.00
Rescheduling a Missed Appointment	100.00	-	-	100.00	100.00	-
Service Reliability Indices						
SAIDI-Annual	2.88	1.93	3.84	0.77	0.84	2.53
SAIFI-Annual	3.54	1.63	2.75	1.57	0.71	2.47
CAIDI-Annual	0.81	1.18	1.40	0.49	1.18	1.02

Unitized Statistics **For the year ended December 31, 2009** **(Alphabetically Listed)**	Oshawa PUC Networks Inc.	Ottawa River Power Corporation	Parry Sound Power Corporation	Peterborough Distribution Incorporated	Port Colborne Hydro Inc.	PowerStream Inc.
# of Customers per sq km of Service Area	352.27	298.91	225.20	547.45	74.79	397.88
# of Customers per km of Line	55.25	71.66	26.39	63.70	29.15	41.75
Average Revenue from Distribution						
Per Customer annually	$ 378.10	$ 351.46	$ 522.60	$ 408.02	$ 575.43	$ 478.63
Per Total kWh Purchased	$ 0.018	$ 0.018	$ 0.019	$ 0.017	$ 0.027	$ 0.019
Average Cost of Power						
Per Customer annually	$ 1,422	$ 1,363	$ 1,997	$ 1,743	$ 1,603	$ 1,939
Per Total kWh Purchased	$ 0.066	$ 0.072	$ 0.073	$ 0.073	$ 0.075	$ 0.075
Avg monthly kWh consumed per customer	1,786	1,588	2,288	1,984	1,774	2,155
Avg Peak (kW) per Customer	3.44	2.72	4.31	3.75	3.55	4.22
OM&A Per Customer	$ 167.62	$ 231.25	$ 368.79	$ 187.30	$ 379.02	$ 183.72
Net Income (Loss) Per Customer	$ 55.55	$ 33.85	$ (10.78)	$ 53.57	$ 15.86	$ 65.68
Net Fixed Assets per Customer	$ 992	$ 786	$ 1,199	$ 1,381	$ 1,257	$ 2,020
SERVICE QUALITY INDICATORS						
Low Voltage Connections	100.00	100.00	100.00	100.00	100.00	97.60
High Voltage Connections	100.00	-	-	100.00	-	-
Telephone Accessibility	62.70	99.40	100.00	78.30	86.50	69.20
Appointments Met	100.00	100.00	100.00	97.80	95.70	100.00
Written Response to Enquires	100.00	100.00	100.00	99.10	100.00	99.10
Emergency Urban Response	100.00	100.00	100.00	91.90	100.00	87.30
Emergency Rural Response	-	-	100.00	-	100.00	-
Telephone Call Abandon Rate	6.00	0.60	-	2.80	2.00	4.10
Appointment Scheduling	100.00	100.00	100.00	81.50	99.90	100.00
Rescheduling a Missed Appointment	-	-	-	94.90	100.00	-
Service Reliability Indices						
SAIDI-Annual	3.49	3.20	1.54	4.60	1.07	1.97
SAIFI-Annual	1.67	2.87	0.06	1.77	1.17	1.23
CAIDI-Annual	2.09	1.11	24.09	2.60	0.92	1.60

Unitized Statistics For the year ended December 31, 2009 (Alphabetically Listed)	PUC Distribution Inc.	Renfrew Hydro Inc.	Rideau St. Lawrence Distribution Inc.	Sioux Lookout Hydro Inc.	St. Thomas Energy Inc.	Thunder Bay Hydro Electricity Distribution Inc.
# of Customers per sq km of Service Area	95.98	321.54	325.72	5.11	492.21	131.03
# of Customers per km of Line	44.84	76.00	65.88	12.99	66.84	42.09
Average Revenue from Distribution						
Per Customer annually	$ 479.02	$ 396.83	$ 371.21	$ 688.43	$ 393.48	$ 362.88
Per Total kWh Purchased	$ 0.021	$ 0.016	$ 0.018	$ 0.025	$ 0.021	$ 0.018
Average Cost of Power						
Per Customer annually	$ 1,406	$ 1,897	$ 1,531	$ 1,277	$ 1,425	$ 1,489
Per Total kWh Purchased	$ 0.063	$ 0.078	$ 0.076	$ 0.046	$ 0.077	$ 0.073
Avg monthly kWh consumed per customer	1,861	2,033	1,683	2,312	1,544	1,690
Avg Peak (kW) per Customer	3.38	3.99	3.27	4.54	2.11	3.08
OM&A Per Customer	$ 241.85	$ 246.99	$ 275.94	$ 416.08	$ 199.90	$ 233.78
Net Income (Loss) Per Customer	$ 55.47	$ 3.08	$ 40.53	$ 33.98	$ 47.62	$ 93.36
Net Fixed Assets per Customer	$ 1,209	$ 1,043	$ 702	$ 1,670	$ 1,167	$ 1,244
SERVICE QUALITY INDICATORS						
Low Voltage Connections	98.20	100.00	100.00	100.00	100.00	94.80
High Voltage Connections	100.00	-	-	-	-	100.00
Telephone Accessibility	65.10	95.70	97.90	97.90	81.60	92.60
Appointments Met	96.10	100.00	99.10	100.00	99.30	100.00
Written Response to Enquires	91.20	-	100.00	100.00	100.00	99.30
Emergency Urban Response	90.20	100.00	100.00	100.00	100.00	95.50
Emergency Rural Response	-	-	-	100.00	-	100.00
Telephone Call Abandon Rate	6.00	6.60	-	2.10	1.10	2.10
Appointment Scheduling	99.10	100.00	100.00	100.00	94.30	100.00
Rescheduling a Missed Appointment	80.00	-	-	-	50.00	100.00
Service Reliability Indices						
SAIDI-Annual	2.14	2.14	0.29	0.32	0.28	4.40
SAIFI-Annual	2.97	2.18	0.15	0.33	0.65	4.11
CAIDI-Annual	0.72	0.98	1.96	0.99	0.43	1.07

Unitized Statistics For the year ended December 31, 2009 (Alphabetically Listed)	Tillsonburg Hydro Inc.	Toronto Hydro-Electric System Limited	Veridian Connections Inc.	Wasaga Distribution Inc.	Waterloo North Hydro Inc.	Welland Hydro-Electric System Corp.
# of Customers per sq km of Service Area	280.75	1095.62	175.26	194.57	76.03	254.84
# of Customers per km of Line	43.19	70.48	50.88	50.29	33.15	49.47
Average Revenue from Distribution						
Per Customer annually	$ 417.25	$ 698.75	$ 416.16	$ 330.13	$ 504.67	$ 377.77
Per Total kWh Purchased	$ 0.015	$ 0.019	$ 0.018	$ 0.032	$ 0.018	$ 0.020
Average Cost of Power						
Per Customer annually	$ 2,252	$ 2,389	$ 1,762	$ 663	$ 1,565	$ 1,463
Per Total kWh Purchased	$ 0.078	$ 0.065	$ 0.077	$ 0.064	$ 0.057	$ 0.076
Avg monthly kWh consumed per customer	2,395	3,085	1,911	869	2,303	1,596
Avg Peak (kW) per Customer	5.30	5.05	3.55	1.74	4.37	3.24
OM&A Per Customer	$ 278.17	$ 259.12	$ 173.84	$ 168.95	$ 172.31	$ 218.72
Net Income (Loss) Per Customer	$ 24.87	$ 73.89	$ 61.91	$ 62.34	$ 96.85	$ 23.04
Net Fixed Assets per Customer	$ 888	$ 2,798	$ 1,330	$ 733	$ 2,154	$ 955
SERVICE QUALITY INDICATORS						
Low Voltage Connections	100.00	96.60	99.20	100.00	100.00	100.00
High Voltage Connections	-	99.00	100.00	-	100.00	-
Telephone Accessibility	-	84.40	74.10	100.00	87.70	99.90
Appointments Met	100.00	99.70	97.90	100.00	99.80	100.00
Written Response to Enquires	-	99.20	100.00	100.00	100.00	100.00
Emergency Urban Response	-	79.50	96.60	97.20	91.30	100.00
Emergency Rural Response	-	-	100.00	100.00	94.70	-
Telephone Call Abandon Rate	-	0.90	4.20	-	3.30	1.90
Appointment Scheduling	-	98.10	96.40	100.00	100.00	99.90
Rescheduling a Missed Appointment	-	98.80	93.10	-	100.00	100.00
Service Reliability Indices						
SAIDI-Annual	-	2.90	3.69	0.83	1.23	1.04
SAIFI-Annual	-	1.86	2.45	0.75	1.03	1.16
CAIDI-Annual	-	1.56	1.51	1.10	1.19	0.90

Unitized Statistics For the year ended December 31, 2009 (Alphabetically Listed)	Wellington North Power Inc.	West Coast Huron Energy Inc.	West Perth Power Inc.	Westario Power Inc.	Whitby Hydro Electric Corporation	Woodstock Hydro Services Inc.
# of Customers per sq km of Service Area	256.29	470.38	342.00	445.00	266.98	511.66
# of Customers per km of Line	47.21	57.89	57.00	50.01	38.21	60.56
Average Revenue from Distribution						
Per Customer annually	$ 535.85	$ 519.01	$ 432.97	$ 391.07	$ 470.69	$ 454.86
Per Total kWh Purchased	$ 0.021	$ 0.012	$ 0.015	$ 0.018	$ 0.021	$ 0.018
Average Cost of Power						
Per Customer annually	$ 1,499	$ 1,803	$ 2,064	$ 1,349	$ 1,367	$ 1,433
Per Total kWh Purchased	$ 0.058	$ 0.042	$ 0.071	$ 0.061	$ 0.062	$ 0.058
Avg monthly kWh consumed per customer	2,170	3,547	2,415	1,843	1,850	2,071
Avg Peak (kW) per Customer	4.08	6.68	4.62	2.89	3.62	3.98
OM&A Per Customer	$ 320.08	$ 381.43	$ 386.73	$ 209.93	$ 214.00	$ 224.13
Net Income (Loss) Per Customer	$ 137.38	$ 63.49	$ (34.68)	$ 85.03	$ 51.01	$ 39.88
Net Fixed Assets per Customer	$ 1,351	$ 1,145	$ 833	$ 1,350	$ 1,582	$ 1,389
SERVICE QUALITY INDICATORS						
Low Voltage Connections	100.00	100.00	100.00	97.90	100.00	100.00
High Voltage Connections	-	-	-	-	-	-
Telephone Accessibility	100.00	99.70	94.70	88.70	94.50	89.80
Appointments Met	99.70	100.00	100.00	100.00	99.00	100.00
Written Response to Enquires	100.00	99.40	92.90	97.70	100.00	100.00
Emergency Urban Response	100.00	100.00	-	89.20	100.00	100.00
Emergency Rural Response	-	-	-	-	100.00	-
Telephone Call Abandon Rate	-	0.30	2.10	8.10	5.90	1.50
Appointment Scheduling	100.00	98.10	100.00	100.00	97.00	96.60
Rescheduling a Missed Appointment	-	100.00	-	-	100.00	-
Service Reliability Indices						
SAIDI-Annual	4.06	2.29	10.83	1.35	2.25	1.65
SAIFI-Annual	1.52	2.99	4.55	0.89	1.57	1.83
CAIDI-Annual	2.66	0.76	2.38	1.52	1.43	0.90

Statistics by Customer Class For the year ended December 31, 2009 (Alphabetically Listed)	Algoma Power Inc.	Atikokan Hydro Inc.	Bluewater Power Distribution Corporation	Brant County Power Inc.	Brantford Power Inc.	Burlington Hydro Inc.
Residential Customers						
Number of Customers	10,630	1,415	31,420	8,171	34,089	57,578
kWh Billed	88,878,032	10,082,213	256,212,050	78,687,855	289,270,611	544,341,574
Distribution Revenue	$ 6,890,829	$ 758,252	$ 9,157,764	$ 2,804,327	$ 8,301,363	$ 16,289,521
kWh Billed per customer	8,361	7,125	8,154	9,630	8,486	9,454
Distribution Revenue per Customer	$ 648	$ 536	$ 291	$ 343	$ 244	$ 283
General Service <50kW Customers						
Number of Customers	1,010	225	3,505	1,286	2,721	4,974
kWh Billed	27,224,772	5,369,225	112,787,581	35,876,347	104,233,438	180,755,371
Distribution Revenue	$ 311,540	$ 278,858	$ 2,800,099	$ 945,956	$ 1,405,603	$ 3,756,965
kWh Billed per customer	26,955	23,863	32,179	27,898	38,307	36,340
Distribution Revenue per Customer	$ 308	$ 1,239	$ 799	$ 736	$ 517	$ 755
General Service >50kW, Larger User (>5000kW) Customers and Sub Transmission						
Number of General Service Customers	47	22	395	106	413	980
Number of Larger User	1	0	3	0	0	0
Number of Sub Transmission	0	0	0	0	0	0
kWh Billed	69,931,762	8,816,765	634,242,204	153,259,555	551,054,884	915,813,870
Distribution Revenue	$ 313,683	$ 101,856	$ 4,441,480	$ 1,817,161	$ 5,056,916	$ 6,186,875
kWh Billed per customer	1,456,912	400,762	1,593,573	1,445,845	1,334,273	934,504
Distribution Revenue per Customer	$ 6,535	$ 4,630	$ 11,159	$ 17,143	$ 12,244	$ 6,313
Scattered Unmetered Loads Customers						
Number of Connections	0	8	257	51	445	26
kWh Billed	0	7,742	2,155,483	496,256	1,617,777	3,636,552
Distribution Revenue	$ -	$ 26,290	$ 94,221	$ 14,883	$ 81,427	$ 124,733
kWh Billed per connection	-	968	8,387	9,731	3,635	139,867
Distribution Revenue per Connection	-	$ 3,286	$ 367	$ 292	$ 183	$ 4,797

Statistics by Customer Class For the year ended December 31, 2009 (Alphabetically Listed)	Cambridge and North Dumfries Hydro Inc.	Canadian Niagara Power Inc.	Centre Wellington Hydro Ltd.	Chapleau Public Utilities Corporation	Chatham-Kent Hydro Inc.	Clinton Power Corporation
Residential Customers						
Number of Customers	44,805	14,248	5,603	1,144	28,463	1,411
kWh Billed	382,507,290	111,596,385	45,838,418	15,271,942	229,006,740	11,682,740
Distribution Revenue	$ 9,579,085	$ 4,526,265	$ 1,497,545	$ 425,335	$ 7,985,703	$ 280,150
kWh Billed per customer	8,537	7,832	8,181	13,350	8,046	8,280
Distribution Revenue per Customer	$ 214	$ 318	$ 267	$ 372	$ 281	$ 199
General Service <50kW Customers						
Number of Customers	4,620	1,228	714	162	3,102	221
kWh Billed	161,342,744	34,463,437	21,099,696	5,199,427	93,203,879	5,329,361
Distribution Revenue	$ 2,654,337	$ 1,051,668	$ 471,110	$ 124,066	$ 2,056,723	$ 98,833
kWh Billed per customer	34,923	28,065	29,551	32,095	30,046	24,115
Distribution Revenue per Customer	$ 575	$ 856	$ 660	$ 766	$ 663	$ 447
General Service >50kW, Larger User (>5000kW) Customers and Sub Transmission						
Number of General Service Customers	709	131	63	14	410	17
Number of Larger User	2	0	0	0	1	0
Number of Sub Transmission	0	0	0	0	0	0
kWh Billed	862,805,038	127,215,229	85,627,855	7,871,532	367,016,329	11,633,401
Distribution Revenue	$ 7,224,560	$ 2,778,279	$ 589,767	$ 68,389	$ 2,860,875	$ 116,242
kWh Billed per customer	1,213,509	971,109	1,359,172	562,252	892,984	684,318
Distribution Revenue per Customer	$ 10,161	$ 21,208	$ 9,361	$ 4,885	$ 6,961	$ 6,838
Scattered Unmetered Loads Customers						
Number of Connections	65	0	2	6	192	11
kWh Billed	2,132,593	0	418,885	7,212	844,634	60,756
Distribution Revenue	$ 66,931	$ -	$ 9,627	$ 1,592	$ 12,122	$ 1,738
kWh Billed per connection	32,809	-	209,443	1,202	4,399	5,523
Distribution Revenue per Connection	$ 1,030	-	$ 4,813	$ 265	$ 63	$ 158

Statistics by Customer Class For the year ended December 31, 2009 (Alphabetically Listed)	COLLUS Power Corporation	Cooperative Hydro Embrun Inc.	E.L.K. Energy Inc.	Eastern Ontario Power Inc.	Enersource Hydro Mississauga Inc.	EnWin Utilities Ltd.
Residential Customers						
Number of Customers	13,152	1,757	9,843	3,104	168,288	76,528
kWh Billed	114,248,439	19,949,042	88,729,098	29,586,436	1,554,921,855	608,088,215
Distribution Revenue	$ 3,509,127	$ 435,106	$ 843,320	$ 938,784	$ 44,995,913	$ 21,658,067
kWh Billed per customer	8,687	11,354	9,014	9,532	9,240	7,946
Distribution Revenue per Customer	$ 267	$ 248	$ 86	$ 302	$ 267	$ 283
General Service <50kW Customers						
Number of Customers	1,609	172	1,148	422	16,800	6,981
kWh Billed	44,285,112	5,021,569	26,797,991	12,783,861	677,577,787	221,722,944
Distribution Revenue	$ 824,192	$ 95,020	$ 83,377	$ 382,927	$ 15,430,070	$ 5,636,594
kWh Billed per customer	27,523	29,195	23,343	30,294	40,332	31,761
Distribution Revenue per Customer	$ 512	$ 552	$ 73	$ 907	$ 918	$ 807
General Service >50kW, Larger User (>5000kW) Customers and Sub Transmission						
Number of General Service Customers	116	12	121	34	4,442	1,178
Number of Larger User	1	0	0	0	10	10
Number of Sub Transmission	0	0	0	0	0	0
kWh Billed	145,683,395	4,153,840	113,522,904	17,770,088	5,463,947,843	1,365,095,519
Distribution Revenue	$ 674,773	$ 67,223	$ 589,701	$ 497,048	$ 52,663,450	$ 17,387,735
kWh Billed per customer	1,245,157	346,153	938,206	522,650	1,227,302	1,149,070
Distribution Revenue per Customer	$ 5,767	$ 5,602	$ 4,874	$ 14,619	$ 11,829	$ 14,636
Scattered Unmetered Loads Customers						
Number of Connections	30	0	0	0	198	29
kWh Billed	503,922	0	0	0	10,112,471	4,647,072
Distribution Revenue	$ 8,261	$ -	$ -	$ -	$ 522,699	$ 150,546
kWh Billed per connection	16,797	-	-	-	51,073	160,244
Distribution Revenue per Connection	$ 275	-	-	-	$ 2,640	$ 5,191

Statistics by Customer Class For the year ended December 31, 2009 (Alphabetically Listed)	Erie Thames Powerlines Corporation	Espanola Regional Hydro Distribution Corporation	Essex Powerlines Corporation	Festival Hydro Inc.	Fort Frances Power Corporation	Greater Sudbury Hydro Inc.
Residential Customers						
Number of Customers	12,550	2,857	25,817	17,311	3,296	41,926
kWh Billed	112,395,473	33,443,599	261,922,934	139,254,714	39,845,835	412,159,188
Distribution Revenue	$ 3,219,337	$ 768,750	$ 6,786,809	$ 5,103,848	$ 833,635	$ 12,627,666
kWh Billed per customer	8,956	11,706	10,145	8,044	12,089	9,831
Distribution Revenue per Customer	$ 257	$ 269	$ 263	$ 295	$ 253	$ 301
General Service <50kW Customers						
Number of Customers	1,234	477	2,015	2,009	418	3,911
kWh Billed	33,991,973	14,046,543	70,093,598	65,362,603	16,286,574	143,769,627
Distribution Revenue	$ 566,057	$ 298,677	$ 592,848	$ 1,619,721	$ 250,074	$ 3,590,003
kWh Billed per customer	27,546	29,448	34,786	32,535	38,963	36,760
Distribution Revenue per Customer	$ 459	$ 626	$ 294	$ 806	$ 598	$ 918
General Service >50kW, Larger User (>5000kW) Customers and Sub Transmission						
Number of General Service Customers	146	25	222	209	47	512
Number of Larger User	2	0	0	2	0	0
Number of Sub Transmission	3	0	0	0	0	0
kWh Billed	240,083,029	16,963,776	225,116,124	341,075,319	25,300,350	389,924,101
Distribution Revenue	$ 1,671,758	$ 122,572	$ 2,012,993	$ 2,333,615	$ 360,752	$ 5,182,403
kWh Billed per customer	1,589,954	678,551	1,014,037	1,616,471	538,305	761,571
Distribution Revenue per Customer	$ 11,071	$ 4,903	$ 9,068	$ 11,060	$ 7,676	$ 10,122
Scattered Unmetered Loads Customers						
Number of Connections	105	24	148	0	7	190
kWh Billed	516,445	170,432	1,747,060	0	61,333	2,252,111
Distribution Revenue	$ 9,133	$ -	$ 62,755	$ -	$ 2,912	$ 84,899
kWh Billed per connection	4,919	7,101	11,804	-	8,762	11,853
Distribution Revenue per Connection	$ 87	$ -	$ 424	-	$ 416	$ 447

Statistics by Customer Class For the year ended December 31, 2009 (Alphabetically Listed)	Grimsby Power Incorporated	Guelph Hydro Electric Systems Inc.	Haldimand County Hydro Inc.	Halton Hills Hydro Inc.	Hearst Power Distribution Company Limited	Horizon Utilities Corporation
Residential Customers						
Number of Customers	9,222	45,023	18,309	18,924	2,332	212,580
kWh Billed	91,249,172	352,708,669	168,226,691	217,916,715	26,719,860	1,597,158,130
Distribution Revenue	$ 2,414,963	$ 13,114,938	$ 7,584,891	$ 5,365,267	$ 458,257	$ 55,192,117
kWh Billed per customer	9,895	7,834	9,188	11,515	11,458	7,513
Distribution Revenue per Customer	$ 262	$ 291	$ 414	$ 284	$ 197	$ 260
General Service <50kW Customers						
Number of Customers	669	3,650	2,381	1,913	388	19,858
kWh Billed	19,294,424	141,492,398	57,269,262	54,916,651	11,429,892	590,326,105
Distribution Revenue	$ 388,562	$ 2,824,471	$ 1,775,022	$ 1,013,246	$ 134,006	$ 11,711,495
kWh Billed per customer	28,841	38,765	24,053	28,707	29,458	29,727
Distribution Revenue per Customer	$ 581	$ 774	$ 745	$ 530	$ 345	$ 590
General Service >50kW, Larger User (>5000kW) Customers and Sub Transmission						
Number of General Service Customers	101	582	137	207	44	2,216
Number of Larger User	0	4	0	0	0	12
Number of Sub Transmission	0	0	0	0	0	0
kWh Billed	67,099,441	979,482,316	109,770,756	216,553,774	38,236,783	3,051,641,417
Distribution Revenue	$ 472,269	$ 7,236,902	$ 1,773,198	$ 2,474,220	$ 192,367	$ 19,998,502
kWh Billed per customer	664,351	1,671,472	801,246	1,046,153	869,018	1,369,677
Distribution Revenue per Customer	$ 4,676	$ 12,350	$ 12,943	$ 11,953	$ 4,372	$ 8,976
Scattered Unmetered Loads Customers						
Number of Connections	81	40	84	140	0	0
kWh Billed	396,807	2,424,418	481,502	902,443	0	0
Distribution Revenue	$ 5,384	$ 47,550	$ 19,713	$ 27,346	$ -	$ -
kWh Billed per connection	4,899	60,610	5,732	6,446	-	-
Distribution Revenue per Connection	$ 66	$ 1,189	$ 235	$ 195	-	-

Statistics by Customer Class For the year ended December 31, 2009 (Alphabetically Listed)	Hydro 2000 Inc.	Hydro Hawkesbury Inc.	Hydro One Brampton Networks Inc.	Hydro One Networks Inc.	Hydro Ottawa Limited	Innisfil Hydro Distribution Systems Limited
Residential Customers						
Number of Customers	1,027	4,781	121,692	1,084,186	269,288	13,636
kWh Billed	15,905,549	55,896,455	1,121,010,160	11,607,000,000	2,256,567,858	158,478,924
Distribution Revenue	$ 202,810	$ 459,030	$ 35,076,490	$ 626,046,000	$ 80,607,007	$ 5,692,353
kWh Billed per customer	15,487	11,691	9,212	10,706	8,380	11,622
Distribution Revenue per Customer	$ 197	$ 96	$ 288	$ 577	$ 299	$ 417
General Service <50kW Customers						
Number of Customers	140	586	7,684	109,208	23,338	855
kWh Billed	4,981,571	20,862,413	296,392,318	7,290,000,000	731,102,854	29,628,747
Distribution Revenue	$ 80,448	$ 93,635	$ 7,199,552	$ 263,006,000	$ 18,047,373	$ 639,448
kWh Billed per customer	35,583	35,601	38,573	66,753	31,327	34,654
Distribution Revenue per Customer	$ 575	$ 160	$ 937	$ 2,408	$ 773	$ 748
General Service >50kW, Larger User (>5000kW) Customers and Sub Transmission						
Number of General Service Customers	11	81	1,645	0	3,370	72
Number of Larger User	0	1	6	0	11	0
Number of Sub Transmission	0	0	0	373	0	0
kWh Billed	4,958,070	101,345,208	2,278,471,429	2,721,000,000	4,510,883,945	50,032,067
Distribution Revenue	$ 28,113	$ 158,413	$ 18,585,172	$ 8,968,000	$ 44,019,818	$ 750,206
kWh Billed per customer	450,734	1,235,917	1,380,055	7,294,906	1,334,186	694,890
Distribution Revenue per Customer	$ 2,556	$ 1,932	$ 11,257	$ 24,043	$ 13,020	$ 10,420
Scattered Unmetered Loads Customers						
Number of Connections	6	4	0	0	2,848	82
kWh Billed	19,706	192,729	0	0	19,879,033	520,289
Distribution Revenue	$ 1,007	$ 1,203	$ -	$ -	$ 536,070	$ 34,074
kWh Billed per connection	3,284	48,182	-	-	6,980	6,345
Distribution Revenue per Connection	$ 168	$ 301	-	-	$ 188	$ 416

Statistics by Customer Class For the year ended December 31, 2009 (Alphabetically Listed)	Kenora Hydro Electric Corporation Ltd.	Kingston Hydro Corporation	Kitchener-Wilmot Hydro Inc.	Lakefront Utilities Inc.	Lakeland Power Distribution Ltd.	London Hydro Inc.
Residential Customers						
Number of Customers	4,777	23,223	76,755	8,243	7,697	131,734
kWh Billed	39,909,017	200,816,087	647,493,718	77,155,275	82,722,597	1,067,984,894
Distribution Revenue	$ 1,189,685	$ 5,323,895	$ 16,684,101	$ 1,848,574	$ 2,391,505	$ 33,503,321
kWh Billed per customer	8,354	8,647	8,436	9,360	10,747	8,107
Distribution Revenue per Customer	$ 249	$ 229	$ 217	$ 224	$ 311	$ 254
General Service <50kW Customers						
Number of Customers	733	3,255	7,425	1,065	1,547	11,914
kWh Billed	25,617,550	96,953,020	241,562,492	36,853,092	44,672,868	392,901,741
Distribution Revenue	$ 327,550	$ 1,849,197	$ 4,332,529	$ 576,899	$ 968,457	$ 8,450,169
kWh Billed per customer	34,949	29,786	32,534	34,604	28,877	32,978
Distribution Revenue per Customer	$ 447	$ 568	$ 584	$ 542	$ 626	$ 709
General Service >50kW, Larger User (>5000kW) Customers and Sub Transmission						
Number of General Service Customers	69	351	992	132	100	1,647
Number of Larger User	0	3	2	0	0	3
Number of Sub Transmission	0	0	0	0	0	0
kWh Billed	43,611,734	431,258,755	928,173,715	144,257,386	84,181,833	1,660,133,648
Distribution Revenue	$ 434,649	$ 2,295,348	$ 10,459,518	$ 1,201,864	$ 855,712	$ 10,248,092
kWh Billed per customer	632,054	1,218,245	933,776	1,092,859	841,818	1,006,142
Distribution Revenue per Customer	$ 6,299	$ 6,484	$ 10,523	$ 9,105	$ 8,557	$ 6,211
Scattered Unmetered Loads Customers						
Number of Connections	0	159	824	94	43	1,489
kWh Billed	0	2,341,330	3,403,820	790,195	165,657	5,570,493
Distribution Revenue	$ -	$ 47,426	$ 153,879	$ 31,864	$ 10,568	$ 58,174
kWh Billed per connection	-	14,725	4,131	8,406	3,852	3,741
Distribution Revenue per Connection	-	$ 298	$ 187	$ 339	$ 246	$ 39

Statistics by Customer Class For the year ended December 31, 2009 (Alphabetically Listed)	Middlesex Power Distribution Corporation	Midland Power Utility Corporation	Milton Hydro Distribution Inc.	Newmarket - Tay Power Distribution Ltd.	Niagara Peninsula Energy Inc.	Niagara-on-the-Lake Hydro Inc.
Residential Customers						
Number of Customers	6,984	6,052	24,832	29,138	45,167	6,507
kWh Billed	59,459,192	47,639,419	230,386,763	261,208,138	396,244,635	63,529,367
Distribution Revenue	$ 2,087,535	$ 1,808,381	$ 7,107,078	$ 8,091,758	$ 13,491,773	$ 2,214,849
kWh Billed per customer	8,514	7,872	9,278	8,965	8,773	9,763
Distribution Revenue per Customer	$ 299	$ 299	$ 286	$ 278	$ 299	$ 340
General Service <50kW Customers						
Number of Customers	780	729	2,203	2,893	4,389	1,230
kWh Billed	20,481,317	24,772,837	73,566,124	92,853,967	128,615,455	33,919,641
Distribution Revenue	$ 282,773	$ 487,411	$ 1,570,851	$ 2,310,777	$ 3,364,595	$ 1,095,985
kWh Billed per customer	26,258	33,982	33,394	32,096	29,304	27,577
Distribution Revenue per Customer	$ 363	$ 669	$ 713	$ 799	$ 767	$ 891
General Service >50kW, Larger User (>5000kW) Customers and Sub Transmission						
Number of General Service Customers	95	112	286	398	847	121
Number of Larger User	1	0	2	0	0	0
Number of Sub Transmission	0	0	0	0	0	0
kWh Billed	102,832,092	128,992,796	363,265,000	316,486,393	636,588,343	74,700,317
Distribution Revenue	$ 380,152	$ 766,955	$ 2,662,035	$ 3,891,854	$ 8,581,980	$ 1,115,534
kWh Billed per customer	1,071,168	1,151,721	1,261,337	795,192	751,580	617,358
Distribution Revenue per Customer	$ 3,960	$ 6,848	$ 9,243	$ 9,779	$ 10,132	$ 9,219
Scattered Unmetered Loads Customers						
Number of Connections	51	12	183	398	420	22
kWh Billed	310,817	528,948	1,259,845	179,150	2,045,397	202,191
Distribution Revenue	$ 7,091	$ 13,743	$ 36,889	$ -	$ 119,866	$ 11,951
kWh Billed per connection	6,094	44,079	6,884	450	4,870	9,191
Distribution Revenue per Connection	$ 139	$ 1,145	$ 202	$ -	$ 285	$ 543

Statistics by Customer Class For the year ended December 31, 2009 (Alphabetically Listed)	Norfolk Power Distribution Inc.	North Bay Hydro Distribution Limited	Northern Ontario Wires Inc.	Oakville Hydro Electricity Distribution Inc.	Orangeville Hydro Limited	Orillia Power Distribution Corporation
Residential Customers						
Number of Customers	16,653	20,850	5,179	56,419	9,814	11,296
kWh Billed	139,365,167	213,412,762	43,042,148	583,830,856	84,392,286	108,280,800
Distribution Revenue	$ 6,962,430	$ 5,534,543	$ 1,556,635	$ 17,558,909	$ 2,986,225	$ 3,165,109
kWh Billed per customer	8,369	10,236	8,311	10,348	8,599	9,586
Distribution Revenue per Customer	$ 418	$ 265	$ 301	$ 311	$ 304	$ 280
General Service <50kW Customers						
Number of Customers	2,071	2,629	798	4,887	1,148	1,359
kWh Billed	60,541,483	87,404,596	20,012,505	179,197,074	35,466,556	48,101,672
Distribution Revenue	$ 2,114,481	$ 1,892,314	$ 427,800	$ 3,985,324	$ 705,587	$ 1,167,744
kWh Billed per customer	29,233	33,246	25,078	36,668	30,894	35,395
Distribution Revenue per Customer	$ 1,021	$ 720	$ 536	$ 815	$ 615	$ 859
General Service >50kW, Larger User (>5000kW) Customers and Sub Transmission						
Number of General Service Customers	169	276	73	873	129	154
Number of Larger User	0	0	0	0	0	0
Number of Sub Transmission	0	0	0	0	0	0
kWh Billed	159,314,312	247,871,397	58,783,293	768,596,138	121,491,113	149,477,236
Distribution Revenue	$ 1,812,098	$ 2,281,600	$ 329,251	$ 6,034,339	$ 697,577	$ 1,613,116
kWh Billed per customer	942,688	898,085	805,251	880,408	941,792	970,631
Distribution Revenue per Customer	$ 10,722	$ 8,267	$ 4,510	$ 6,912	$ 5,408	$ 10,475
Scattered Unmetered Loads Customers						
Number of Connections	2	21	19	679	35	153
kWh Billed	496,200	311,871	129,179	4,143,540	373,171	846,523
Distribution Revenue	$ -	$ 9,587	$ 4,204	$ 119,036	$ 12,798	$ 40,790
kWh Billed per connection	248,100	14,851	6,799	6,102	10,662	5,533
Distribution Revenue per Connection	$ -	$ 457	$ 221	$ 175	$ 366	$ 267

Statistics by Customer Class For the year ended December 31, 2009 (Alphabetically Listed)	Oshawa PUC Networks Inc.	Ottawa River Power Corporation	Parry Sound Power Corporation	Peterborough Distribution Incorporated	Port Colborne Hydro Inc.	PowerStream Inc.
Residential Customers						
Number of Customers	47,769	8,851	2,751	30,680	8,170	283,665
kWh Billed	490,807,351	79,726,454	34,644,939	283,366,850	63,037,704	2,693,171,018
Distribution Revenue	$ 10,503,425	$ 2,025,174	$ 937,164	$ 7,729,832	$ 2,843,518	$ 77,327,995
kWh Billed per customer	10,275	9,008	12,594	9,236	7,716	9,494
Distribution Revenue per Customer	$ 220	$ 229	$ 341	$ 252	$ 348	$ 273
General Service <50kW Customers						
Number of Customers	3,897	1,394	540	3,609	874	29,594
kWh Billed	134,251,798	34,976,027	16,578,434	117,563,108	23,936,127	1,017,353,775
Distribution Revenue	$ 2,789,117	$ 623,517	$ 303,333	$ 2,153,680	$ 674,350	$ 21,418,543
kWh Billed per customer	34,450	25,090	30,701	32,575	27,387	34,377
Distribution Revenue per Customer	$ 716	$ 447	$ 562	$ 597	$ 772	$ 724
General Service >50kW, Larger User (>5000kW) Customers and Sub Transmission						
Number of General Service Customers	517	144	68	363	80	4,654
Number of Larger User	1	0	0	2	0	1
Number of Sub Transmission	0	0	0	0	0	0
kWh Billed	495,241,670	77,293,266	37,828,107	381,906,239	101,400,949	4,510,511,478
Distribution Revenue	$ 4,550,193	$ 820,651	$ 418,864	$ 2,860,209	$ 1,415,139	$ 42,401,537
kWh Billed per customer	956,065	536,759	556,296	1,046,318	1,267,512	968,961
Distribution Revenue per Customer	$ 8,784	$ 5,699	$ 6,160	$ 7,836	$ 17,689	$ 9,109
Scattered Unmetered Loads Customers						
Number of Connections	304	73	19	383	0	2,781
kWh Billed	2,963,094	2,376,275	59,160	1,713,817	0	12,752,938
Distribution Revenue	$ 66,781	$ 9,053	$ 4,210	$ 84,857	$ -	$ 438,584
kWh Billed per connection	9,747	32,552	3,114	4,475	-	4,586
Distribution Revenue per Connection	$ 220	$ 124	$ 222	$ 222	-	$ 158

Statistics by Customer Class For the year ended December 31, 2009 (Alphabetically Listed)	PUC Distribution Inc.	Renfrew Hydro Inc.	Rideau St. Lawrence Distribution Inc.	Sioux Lookout Hydro Inc.	St. Thomas Energy Inc.	Thunder Bay Hydro Electricity Distribution Inc.
Residential Customers						
Number of Customers	29,028	3,613	4,974	2,296	14,374	44,443
kWh Billed	348,619,359	30,635,928	45,271,935	33,747,939	115,181,982	348,392,935
Distribution Revenue	$ 8,375,415	$ 849,085	$ 1,156,502	$ 1,049,004	$ 742,203	$ 10,704,867
kWh Billed per customer	12,010	8,479	9,102	14,699	8,013	7,839
Distribution Revenue per Customer	$ 289	$ 235	$ 233	$ 457	$ 52	$ 241
General Service <50kW Customers						
Number of Customers	3,341	503	774	392	1,672	4,486
kWh Billed	91,450,221	13,000,400	20,399,815	16,172,932	37,210,577	138,834,577
Distribution Revenue	$ 2,278,648	$ 247,632	$ 375,059	$ 339,855	$ 1,076,514	$ 2,675,518
kWh Billed per customer	27,372	25,846	26,356	41,257	22,255	30,948
Distribution Revenue per Customer	$ 682	$ 492	$ 485	$ 867	$ 644	$ 596
General Service >50kW, Larger User (>5000kW) Customers and Sub Transmission						
Number of General Service Customers	439	64	66	39	192	524
Number of Larger User	0	0	0	0	0	0
Number of Sub Transmission	0	0	0	0	0	0
kWh Billed	258,998,141	52,230,300	43,072,665	21,993,284	133,678,548	481,807,121
Distribution Revenue	$ 3,630,937	$ 284,351	$ 354,195	$ 308,481	$ 3,861,714	$ 3,093,591
kWh Billed per customer	589,973	816,098	652,616	563,930	696,242	919,479
Distribution Revenue per Customer	$ 8,271	$ 4,443	$ 5,367	$ 7,910	$ 20,113	$ 5,904
Scattered Unmetered Loads Customers						
Number of Connections	17	0	49	13	5	469
kWh Billed	823,448	0	348,019	42,486	9,288	1,995,125
Distribution Revenue	$ 24,220	$ -	$ 16,617	$ 3,620	$ 612	$ 134,844
kWh Billed per connection	48,438	-	7,102	3,268	1,858	4,254
Distribution Revenue per Connection	$ 1,425	-	$ 339	$ 278	$ 122	$ 288

Statistics by Customer Class For the year ended December 31, 2009 (Alphabetically Listed)	Tillsonburg Hydro Inc.	Toronto Hydro-Electric System Limited	Veridian Connections Inc.	Wasaga Distribution Inc.	Waterloo North Hydro Inc.	Welland Hydro-Electric System Corp.
Residential Customers						
Number of Customers	5,907	611,357	101,547	11,010	45,113	19,803
kWh Billed	51,473,373	5,037,152,555	942,215,878	67,145,248	397,106,489	152,795,281
Distribution Revenue	$ 1,653,970	$ 193,430,604	$ 27,976,891	$ 2,752,651	$ 13,521,851	$ 5,402,478
kWh Billed per customer	8,714	8,239	9,279	6,099	8,802	7,716
Distribution Revenue per Customer	$ 280	$ 316	$ 276	$ 250	$ 300	$ 273
General Service <50kW Customers						
Number of Customers	675	64,781	8,501	801	5,300	1,725
kWh Billed	24,437,614	2,223,765,510	302,228,227	12,946,028	179,259,397	54,842,891
Distribution Revenue	$ 500,966	$ 60,336,439	$ 6,464,083	$ 340,326	$ 3,777,338	$ 902,878
kWh Billed per customer	36,204	34,327	35,552	16,162	33,823	31,793
Distribution Revenue per Customer	$ 742	$ 931	$ 760	$ 425	$ 713	$ 523
General Service >50kW, Larger User (>5000kW) Customers and Sub Transmission						
Number of General Service Customers	87	12,953	1,049	33	661	172
Number of Larger User	0	47	4	0	1	2
Number of Sub Transmission	0	0	0	0	0	0
kWh Billed	107,671,901	17,158,962,810	1,202,171,868	15,477,900	774,171,690	187,757,826
Distribution Revenue	$ 495,519	$ 201,544,335	$ 8,935,284	$ 275,966	$ 7,382,623	$ 1,441,330
kWh Billed per customer	1,237,608	1,319,920	1,141,664	469,027	1,169,444	1,079,068
Distribution Revenue per Customer	$ 5,696	$ 15,503	$ 8,486	$ 8,363	$ 11,152	$ 8,284
Scattered Unmetered Loads Customers						
Number of Connections	69	1,105	893	25	14	214
kWh Billed	93,288	57,731,695	5,832,532	167,496	1,943,333	1,170,354
Distribution Revenue	$ 18,514	$ 2,449,890	$ 181,472	$ 2,240	$ 120,883	$ 41,404
kWh Billed per connection	1,352	52,246	6,531	6,700	138,810	5,469
Distribution Revenue per Connection	$ 268	$ 2,217	$ 203	$ 90	$ 8,635	$ 193

Statistics by Customer Class For the year ended December 31, 2009 (Alphabetically Listed)	Wellington North Power Inc.	West Coast Huron Energy Inc.	West Perth Power Inc.	Westario Power Inc.	Whitby Hydro Electric Corporation	Woodstock Hydro Services Inc.
Residential Customers						
Number of Customers	3,056	3,231	1,786	19,033	36,762	13,429
kWh Billed	25,181,847	25,808,454	15,500,136	220,302,768	347,011,249	93,622,824
Distribution Revenue	$ 865,937	$ 899,422	$ 414,577	$ 4,543,177	$ 11,826,831	$ 3,851,591
kWh Billed per customer	8,240	7,988	8,679	11,575	9,439	6,972
Distribution Revenue per Customer	$ 283	$ 278	$ 232	$ 239	$ 322	$ 287
General Service <50kW Customers						
Number of Customers	480	474	241	2,435	1,926	1,170
kWh Billed	11,485,058	14,454,059	8,193,778	74,730,675	74,119,383	41,369,827
Distribution Revenue	$ 297,891	$ 313,302	$ 138,361	$ 1,276,314	$ 1,715,967	$ 825,248
kWh Billed per customer	23,927	30,494	33,999	30,690	38,484	35,359
Distribution Revenue per Customer	$ 621	$ 661	$ 574	$ 524	$ 891	$ 705
General Service >50kW, Larger User (>5000kW) Customers and Sub Transmission						
Number of General Service Customers	49	53	20	276	435	200
Number of Larger User	0	1	0	0	0	0
Number of Sub Transmission	0	0	0	0	0	0
kWh Billed	49,673,928	113,936,823	32,104,699	173,599,014	411,691,886	203,912,523
Distribution Revenue	$ 559,777	$ 793,795	$ 194,019	$ 1,886,930	$ 3,766,927	$ 1,585,466
kWh Billed per customer	1,013,754	2,109,941	1,605,235	628,982	946,418	1,019,563
Distribution Revenue per Customer	$ 11,424	$ 14,700	$ 9,701	$ 6,837	$ 8,660	$ 7,927
Scattered Unmetered Loads Customers						
Number of Connections	3	4	5	61	390	39
kWh Billed	9,305	94,310	16,368	370,057	2,431,741	647,213
Distribution Revenue	$ 218	$ 3,352	$ 68	$ 23,596	$ 123,686	$ 8,113
kWh Billed per connection	3,102	23,578	3,274	6,067	6,235	16,595
Distribution Revenue per Connection	$ 73	$ 838	$ 14	$ 387	$ 317	$ 208

Glossary of Terms

FINANCIAL INFORMATION

	Aggregation of Trial Balance (RRR section 2.1.7) accounts
Cash & cash equivalents	1005-1070
Receivables	1100-1170
Inventory	1305-1350
Inter-company	1200+1210
Other current assets	1180-1190
Property plant & equipment	1605-2075
Accumulated depreciation & amortization	2105-2180
Regulatory assets (net)	1505-1595
Inter-company	1480-1490
Other non-current assets	1405-1475
Accounts payable & accrued charges	2205-2220 + 2250-2256 +2294
Current Portion of Future Income Taxes	2296
Other current liabilities	2285 - 2292 +2264
Inter-company	2240+2242
Loans and notes payable, and current portion of long term debt	2225+ 2260-2262 + 2268-2272
Long-term debt	2505-2525
Inter-company debt & advances	2530-2550
Regulatory liabilities	2405+2425
Other deferred amounts & customer deposits	2305 + 2308-2348 + 2410+2415+2435
Employee future benefits	2306
Future income taxes	2350
Shareholders' Equity	3005-3065
Power and distribution revenue	4006-4245
Cost of power and related costs	4705-4750
Other income	4305-4415 +6305
Operating	4505-4565 + 4805-4850 + 5005-5096
Maintenance	4605-4640 + 4905-4965 + 5105-5195
Administrative	5305-5695
Other	5205-5215
Depreciation and amortization	5705-5740
Financing	6005-6045
Current Income Tax	6110
Future Income Tax	6115

Glossary of Terms

FINANCIAL RATIOS

Liquidity Ratios measure the availability of cash to pay debt.

Current Ratio is a financial ratio that measures whether or not a firm has enough resources to pay its debts over the next 12 months.

Leverage Ratios are the financial statement ratios which show the degree to which the business is leveraging itself through its use of borrowed money. Long-term debt and long-term intercompany financing.

Debt Ratio indicates what proportion of long-term debt and long-term intercompany financing a company has relative to its assets.

Debt to Equity Ratio is a financial ratio indicating the relative proportion of equity and long-term debt plus long-term intercompany financing used to finance a company's assets.

Interest Coverage Ratio is used to determine a firm's ability to pay interest on outstanding debt.

Profitability Ratios measure the firm's use of its assets and control of its expenses to generate an acceptable rate of return.

Return on Equity measures the rate of return on the ownership interest (shareholders' equity) of the common stock owners and a firm's efficiency at generating profits from every dollar of net assets, and shows how well a company uses investment dollars to generate earnings growth. This is not regulatory return.

Glossary of Terms

GENERAL STATISTICS

Population Served is the estimated number of people served as customers of the utility.

Municipal Population is the Stats Canada population of the municipalities served. May not equal Population Served as other utilities may also serve the same community.

Seasonal Population represents cottagers etc.

Total kWh Purchased equals "Total kWh sold (excluding losses)" plus "Distribution System Losses".

Total kWh Sold (excluding losses) is the total kWh consumed within service territory.

Distribution System Losses is the sum of distribution system line losses, metering error, and energy theft.

Residential Customers applies to an account taking electricity at 750 volts or less where the electricity is used exclusively in a separate metered living accommodation.

General Service < 50 kW Customers applies to a non residential account taking electricity at 750 volts or less whose average monthly maximum demand is less than, or is forecast to be less than, 50 kW.

General Service > 50 to 5,000 kW Customers applies to a non residential account whose average monthly maximum demand used for billing purposes is greater than, or is forecast to be greater than, 50 kW but less than 5,000 kW.

Large User Customers applies to an account whose average monthly maximum demand used for billing purposes is greater than, or is forecast to be greater than, 5,000 kW.

Sub-Transmission applies to an account who has embedded supply to Local Distribution Companies or an account that is directly connected to and supplied by the Distributors assets.

Unmetered Scattered Load refers to certain instances where connections can be provided without metering.

Winter Peak (kW) is the peak load on the distributor system from October to March.

Summer Peak (kW) is the peak load on the distributor system from April to September.

Average Peak (kW) is the average of daily peaks throughout the year.

Capital Additions represents the investment for assets placed in-service.

Glossary of Terms

SERVICE QUALITY INDICATORS

Low Voltage Connections is the percentage of new low voltage (<750 Volts) connection requests where the connection is made within 5 working days of all prerequisites (engineering, safety, etc.) being met. Must be met 90% of the time.

High Voltage Connections is the percentage of new high voltage (>=750 Volts) connection requests where the connection is made within 10 working days of all prerequisites (engineering, safety, etc.) being met. Must be met 90% of the time.

Telephone Accessibility is the percentage of calls to the utility's general inquiry number that are answered in person within 30 seconds. Must be met 65% of the time.

Appointments Met is the percentage of appointments involving a customer premises visit where the appointment date and time (morning or afternoon) is met. Must be met 90% of the time

Written Response to Enquires is the percentage of customer inquiries relating to a customer's account and requiring a written response where the response is provided within 10 working days of receipt of the inquiry. Must be met 80% of the time.

Emergency Urban Response is the percentage of emergency (fire, police, etc.) trouble calls where a qualified service person is on site within 60 minutes of the call. Urban areas are defined by the respective municipality. Must be met 80% of the time.

Emergency Rural Response is the percentage of emergency (fire, police, etc.) trouble calls where a qualified service person is on site within 120 minutes of the call. Rural areas are defined by the respective municipality. Must be met 80% of the time.

Telephone Call Abandon Rate is the percentage of qualified calls (abandoned after 30 seconds) to a distributor's customer care telephone number that are abandoned before they are answered. Must be less than 10%.

Appointment Scheduling is the percentage of when a customer requests an appointment with a distributor, the distributor shall schedule the appointment to take place with in 5 business days. Must be met 90% of the time.

Rescheduling a Missed Appointment is the percentage of missed appointments that the customer is contacted within 1 business day to reschedule the appointment. Must be met 100% of the time.

SAIDI is the average forced sustained interruption duration per customer served per year (measured in hours). Calculation is "Total Customer Hours of Interruptions" divided by "Total Number of Customers".

SAIFI is the average number of forced sustained interruptions experienced per customer served per year (measured in outages). Calculation is the "Total Customer Interruptions" divided by "Total Number of Customers".

CAIDI is the average forced sustained interruption duration experienced by interrupted customers per year (measured in hours). Calculation is SAIDI divided by SAIFI.

INTERROGATORIES OF ENERGY PROBE RESEARCH FOUNDATION

INTERROGATORY 36:

Reference(s): Exhibit D1, Tab 8, Schedule 1, page 5

This page contains a statement from the Capgemini study that "poor reliability may discourage some companies from locating in Toronto".

a) Please elaborate on the basis for the statement.

b) Is THESL relying on this statement for justification of its capital program?

c) Does THESL have other studies showing that companies interested in locating in Toronto have been dissuaded by poor reliability? If so, please provide them.

RESPONSE:

a) The City of Toronto is the economic capital of Canada which is part of the G8 world economic powers which prompted THESL to compare itself to an international peer group at similar level. The following reports provide evidence of the global competition that international cities, like Toronto, face:

- Towards an Agenda for Prosperity: Toronto's Place in the World – Greg Clark 2007
- World Cities and Economic Development: Case Studies in Economic Strategies to Address Globalisation in Established and Emerging Cities – Greg Clark 2007
- Benchmarking Toronto's Economic Performance – City of Toronto 2007

Studies show that power outage is the most common factor of business interruptions resulting in significant losses for a company. This is supported by the "Capgemini study" and the Business Continuity Management Benchmarking Reports:

INTERROGATORIES OF ENERGY PROBE RESEARCH FOUNDATION

- Business Continuity Study Benchmark Report – Contingency Planning & Management/KPMG 2002
- Business Continuity Management Benchmarking Report – Continuity Insights and KPMG Advisory Services 2008

b) The current 2011 THESL proposed capital program does not use this statement as justification. The statement is used to communicate the important relationship between service reliability and economic impact to the City of Toronto.

c) No.

INTERROGATORIES OF ENERGY PROBE RESEARCH FOUNDATION

INTERROGATORY 37:

Reference(s): Exhibit D1, Tab 8, Schedule 1, page 10

Chart 3 on this page shows an improving trend for reliability performance of underground equipment. This appears to be at odds with statements in the schedule that underground cable replacements need to be accelerated due to reliability concerns.

Please explain.

RESPONSE:

Though Chart 3 does show that underground equipment reliability is improving, it can be seen in Exhibit B1, Tab 14, Schedule 1, Chart 10/11, that the majority of this improvement comes from other types of equipment while underground cables are still a significant SAIFI/SAIDI contributor.

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INTERROGATORY 38:

Reference(s): Exhibit D1, Tab 8, Schedule 1, page 11

Chart 4 on this page shows direct buried cable contribution to reliability indices.

a) Is THESL relying on this reliability data to support its increasing capital program to replace direct buried cables?

b) Contribution to SAIFI and SAIDI appears to be stable with 2008 and 2009 at least as good or better than performance in 2005 and 2006. Please explain why expanded cable replacement programs are necessary when reliability does not appear to support an accelerated program.

RESPONSE:

a) THESL does use the reliability data presented in Table 4 but does not solely rely on this data to support the increasing capital. From Table 4, it can be seen that over a five-year period, the trend has not shown any significant rise or fall, but is fluctuating. This shows that there is no clear indication about a steady increase or decrease in SAIDI or SAIFI contribution from direct-buried cable which still remain at an unacceptable high level. THESL, in addition to the reliability data, also reviews the age, end-of-life, failure history, and asset condition of underground direct-buried cables as per the methodology described in Exhibit C1, Tab 6, Schedule 1.

b) Reliability numbers over a five-year trend have shown that SAIDI and SAIFI for direct-buried cables remain at an unacceptably high level. The five-year trend has produced a consistent set of cable failures despite the number of direct-buried cables

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that have been replaced. Cable failures are still occurring at a consistent rate despite the decrease in direct-buried cables when compared to 2005.

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INTERROGATORY 39:

Reference(s): Exhibit D1, Tab 8, Schedule 1, page 13

Chart 7 on this page shows the SAIFI trend for underground system related outages for the period 2005 to 2009.

a) Is THESL relying on this reliability data to support its increasing capital program to replace direct buried cables?

b) Contribution to SAIFI appears to be stable with 2008 and 2009 at least as good or better than performance in 2005 and 2006. Please explain why expanded cable replacement is necessary when reliability does not appear to support an accelerated program.

RESPONSE:

a) and b) Please see response to Energy Probe Interrogatory 38 at Exhibit R1, Tab 6, Schedule 38.

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INTERROGATORY 40:

Reference(s): Exhibit D1, Tab 8, Schedule 1, page 14

This page describes the increased investment in PILC cable replacement. An undersupply of PILC cable manufacturers and a lack of skills among the workforce to install and maintain this cable type.

a) How many cable manufacturers are still providing PILC cable?

b) Is THESL providing training to its maintenance staff on PILC cable? If yes, please explain why maintaining these skills is a problem. If no, please explain why it is not possible to continue the training.

RESPONSE:

a) There are currently two manufacturers offering PILC cable:
- Okonite
- Prysmian

Okinite is the only North American supplier and is the only supplier approved by THESL. Prysmian's manufacturing operations are currently located in Malaysia.

b) THESL provides training for its maintenance staff on PILC cable and will need to continue to do so as needed, until all PILC cable has been replaced. This training is very specific, compared to work on other cable types, and requires specific resource designation which may limit THESL productivity in the future. With less and less PILC cable in the system less specifically trained resources will be required.

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INTERROGATORY 41:

Reference(s): Exhibit D1, Tab 8, Schedule 6.1

Page 2 of this schedule contains the statement that "The increased capital cost for 2011 is required primarily to support further efforts to "green" THESL's fleet – i.e., reduce greenhouse gas emissions through reductions in fuel consumption."

a) Is the greening of the fleet initiative a legislative or regulatory requirement?
b) Please describe the consequences of not investing in greening the fleet?
c) What annual emissions reductions are associated with the greener fleet options vs. the conventional fleet alternatives?
d) How much could the proposed expenditures of $13.3 M in 2011 shown in Table 1 be reduced if greening of the fleet was not pursued?

RESPONSE:

a) No. Greening the fleet is a key initiative within the Toronto Hydro Corporate Responsibility Plan. The initiative is also driven as an effort to continue to modernize the utility.

b)
   i. Lost opportunity to benefit from operational cost savings associated with lower fuel consumption of hybrid and advanced technology vehicles.
   ii. Prevent the fleet from meeting GHG reduction targets set as part of the Corporate Responsibility Plan.
   iii. Prevent Toronto Hydro from acting as a public example of environmental and social responsibility, as fleet vehicles are highly visible to the public at large.

INTERROGATORIES OF ENERGY PROBE RESEARCH FOUNDATION

iv. Prevent Toronto Hydro from introducing advanced technologies such as Electric Vehicles into the fleet as part of its Electric Vehicle program.

c) By purchasing hybrid vehicles in 2011 as part of an effort to green the fleet, emissions reductions of approximately 113 tonnes CO2e would be expected in the full year of 2012.

d) $2,012,000.

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INTERROGATORY 42:

Reference(s): Exhibit D1, Tab 9, Schedule 8

This schedule describes the Energy Storage Project with a projected cost of $30.0 M all of which is planned for 2011.

a) Page 2 of G1-2-1 also lists an Energy Storage Project with $1.1 M planned for 2011. Please explain the differences between these two projects.

b) The description of the Energy Storage Project in D1-9-8 does not include an analysis of the consequences of delaying the project beyond 2011. Please provide the analysis.

RESPONSE:

a) The $1.1M Energy Storage project in Exhibit G1, Tab 2, Schedule 1 is a demonstration project for new advances in technology, including state-of-the-art lithium-ion and lithium-polymer battery systems. In co-operation with universities, advances in battery management systems and power conversion and conditioning systems will also be developed and demonstrated. The storage system will be highly integrated with other smart grid components, including transformer smart meters, power line monitors, self-healing switches, and energy management systems.

In contrast, the $30.0M energy storage system in Exhibit D1, Tab 9, Schedule 8 incorporates 4MW capacity at a downtown station using commercially available sodium-sulphur battery technology to support grid reliability. These systems have been deployed in other utilities such as American Electric Power to improve grid reliability and defer conventional reinforcement. This $30.0M Energy Storage

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Project is viewed as early commercialization to confirm distribution grid benefits for Toronto.

b) The consequences of delaying the Energy Storage Project in Exhibit D1, Tab 9, Schedule 8 beyond 2011 are difficult to assess. Station outages or area outages, which could be mitigated by implementation of the Energy Storage Project will occur, but the frequency and duration of these outages are difficult to predict because they are subject to many external factors.

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INTERROGATORY 43:

Reference(s): Exhibit D1, Tab 8, Schedule 11 – Asset Condition Assessment

On Pages 2-3 of the ACA, a list of 21 asset classes is presented.

For each of these classes please provide the criteria used to assess condition and the relative weighting of each criterion.

RESPONSE:

Refer to the attached summary table for the relative weights by asset class and condition criteria. It should be noted that where applicable, multiple assets that had identical criteria and weights were grouped into a single asset class. Accordingly, the following assets are presented within the table as a single asset class titled "Circuit Breakers": Air Blast Circuit Breakers, Air Magnetic Circuit Breakers, Oil Circuit Breakers, Oil KSO Circuit Breakers, SF6 Circuit Breakers and Vacuum Circuit Breakers.

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Condition Criteria	Assets & Asset Classes														
	Station Transformers	Station Switchgear	Circuit Breakers	Network Transformers	Submersible Transformers	Padmounted Transformers	ATS	Cable Chambers	Wood Poles	3φ Man. O/H Switches	3φ Rem. O/H Switches	SCADA Switches	Pad Switches	Network Vaults	U/G Cable
Age	4	4	3	3	3	3	3						3	2	1
Corrosion & Paint	1			1	1	2							2		
Oil Leaks	1			2	2	1									
Dirt/Debris/ Contamination		1		1										1	
Bushings	1			1	1	2									
Fuses														1	
Grounding/Shunt Contact					1	1		1		1	1	1	1	1	
Other	2		2	2			2								
Breaker Contact Resistance			3												
Breaker Trip/Close			3												
Breaker Interlocks/ Drive Rods			3												
Pothead Termination				1											

Witness Panel(s): 3

INTERROGATORIES OF ENERGY PROBE RESEARCH FOUNDATION

Condition Criteria	Assets & Asset Classes														
	Station Transformers	Station Switchgear	Circuit Breakers	Network Transformers	Submersible Transformers	Padmounted Transformers	ATS	Cable Chambers	Wood Poles	3ϕ Man. O/H Switches	3ϕ Rem. O/H Switches	SCADA Switches	Pad Switches	Network Vaults	U/G Cable
Phase Barriers					1	1	1						1		
Switch Unit				2											
Switch Insulator										2	2	2			
Mechanism										3	3	3			
Blade/Arm Mounting												2			
Arc Suppressors/ Interrupters/Horns										2	2	2	2		
Operations										2	2	2			
Remote Open/Close											4	4			
Transformer Gaskets				1	1	2	1								
Concrete Base						2							2		
Latches/Handles/ Locks/Doors/Entry						1		1		1	1	1		1	
Floor/Roof Walls/Slabs								4						2	
Ducts/Cable								1						1	

INTERROGATORIES OF ENERGY PROBE RESEARCH FOUNDATION

Condition Criteria	Assets & Asset Classes														
	Station Transformers	Station Switchgear	Circuit Breakers	Network Transformers	Submersible Transformers	Padmounted Transformers	ATS	Cable Chambers	Wood Poles	3ϕ Man. O/H Switches	3ϕ Rem. O/H Switches	SCADA Switches	Pad Switches	Network Vaults	U/G Cable
Racking															
Working Space								3							
Drain/Sump Pump														1	
Vents/Grills/ Ventilation														1	
Flooding								1						2	
Wood Pole Strength									5						
Cross Arm Rot									2						
Overall Condition									3						
Connections/ Terminations/ IR Scan		3			1	2				1	1	1	3		
Oil Quality Analysis	3														
Dissolved Gas Analysis	4														
Fault Rate															2

Witness Panel(s): 3

INTERROGATORIES OF ENERGY PROBE RESEARCH FOUNDATION

INTERROGATORY 44:

Reference(s): Exhibit D1, Tab 8, Schedule 11 – Asset Condition Assessment

On page 3 of the ACA the following statement appears:

> "Also, since the condition information for Underground Cables has not yet been incorporated into the Calculator, the 2010 data were compiled and assessed separately, using the same methodology as in 2009"

Please explain the methodology used in 2009.

RESPONSE:

The methodology used in 2009, and applied to the 2010 data, involved calculating health index using cable age and the historical count of faults seen by the cable over a nine-year span.

INTERROGATORIES OF ENERGY PROBE RESEARCH FOUNDATION

INTERROGATORY 45:

Reference(s): **Exhibit D1, Tab 8, Schedule 11 – Asset Condition Assessment**

On page 12 of the ACA the following statement appears:

> "As age remains an important parameter for many assets, a systematic age verification process has been undertaken"

a) How important is age of an asset in the health index computation?

b) Using the example of direct buried underground cables, please explain how age is used in the health index computation.

RESPONSE:

a) Age can be an important component of the health index computation, specifically where limited objective testing or condition information is available. The rationale is that the longer an asset has been in service, there is a greater likelihood that the asset would be exposed to electrical stresses, and there is a greater risk of failure.

b) For details on the condition parameters, weights and condition criteria, refer to the attached figures taken from the 2009 Asset Condition Assessment, used in support of the EB-2009-0139 application.

INTERROGATORIES OF ENERGY PROBE RESEARCH FOUNDATION

Item	Condition Parameter	Weight
1	Cable Failures	2
2	Age	1

Figure 1: Condition Parameters and Weights

Condition Factor	Cable Failures (faults/yr/km)	Age (years)
4	0	<=17
3	0.006696	
2	0.013393	>17 && <=20
1	0.044643	>20 && <=25
0	0.071429	>25

For age (or install date) the condition factor 3 was not used.

Figure 2: Condition Criteria