INTERROGATORIES OF ONTARIO ENERGY BOARD STAFF

INTERROGATORY 1:

Reference(s): C1/T2/S1/p1

The following is stated with respect to the Board's direction in its EB-2007-0680 Decision directing THESL to file a complete and updated Rudden study at the Company's next complete COS application and THESL's subsequent filing of a letter with the Board dated June 15, 2009 requesting that THESL be relieved of the requirement to fulfill that directive due to subsequent organization consolidation:

"As a result of these organizational changes, THESL takes the view that the substance of any shared services study that it might now perform has been so reduced that it would no longer be of any significant value to the Board, stakeholders, or THESL, and that any costs so undertaken would be arguably imprudent."

a) Please state whether or not THESL is planning any further organizational changes that would further reduce the level of shared services between THESL and its affiliates.

b) Please elaborate on why THESL is of the view that any costs so undertaken would be arguably imprudent. Please include discussion of the costs of such a study relative to the magnitude of the continuing shared services and their costs. Has THESL investigated any government training funds for applicability to their situation? If so, what were the outcomes? If not why not?

RESPONSE:

a) At this time, THESL is not planning any further organizational changes that would further reduce the level of shared services.

INTERROGATORIES OF ONTARIO ENERGY BOARD STAFF

b) THESL is of the view that any costs so undertaken would be arguably imprudent due to the significant decrease in shared services costs for 2010. THESL has not obtained an estimate for the undertaking of such a shared services study.

INTERROGATORIES OF ONTARIO ENERGY BOARD STAFF

INTERROGATORY 2:

Reference(s): Q1/T4/S1-1/p.2

In response to the Board's direction to THESL in its EB-2007-0680 Decision that the Board expected that THESL "conduct a study into the capability, costs and benefits of incorporating into the Applicant system, a significant (up to 300MW) component of bi-directional distributed generation in Toronto," THESL provided a study by Navigant Consulting Inc. entitled "Distributed Generation in Central and Downtown Toronto."

It is stated that "During the course of the study, the Ontario government passed the Green Energy Act which further enhances Ontario's focus on renewable generation, DG and CDM."

Please state the extent to which the study reflects the impact of the Green Energy Act, and if it is not fully reflected, please state whether or not Navigant believes the passage of the Act would have any significant impact on the conclusions of its study.

RESPONSE:

The study reflects the impact of the Green Energy Act. The study used the Feed-In-Tariffs proposed in March 2009 to understand the potential market penetration of Feed-In-Tariff eligible generation for Toronto. Please refer to pages 18, 23, 24 and Table 5 of Exhibit Q1, Tab 4 Schedule 1-2 (Manager's Report) for more details. The Feed-In-Tariff contract prices announced by the Ontario Power Authority on September 30, 2009 were unchanged from those used in the study. The capacity size range for the 71.3 cents/kWh contract price changed from the 10 kW to 100 kW range used in the study to 10 kW to

INTERROGATORIES OF ONTARIO ENERGY BOARD STAFF

250 kW range. This small change does not have a material impact on the study results or conclusions.

INTERROGATORIES OF ONTARIO ENERGY BOARD STAFF

INTERROGATORY 3:

Reference(s): Q1/T5/S1

In response to the Board's direction to THESL in its EB-2007-0680 Decision that the Board expected that THESL "will develop the ability to track productivity gains throughout its operations in a programmatic manner that will appropriately inform its next rebasing application", THESL filed a report prepared by KeyWillow Consulting entitled "An Analysis of Productivity Improvements at Toronto Hydro-Electric System Limited."

a) Please state whether in undertaking its analysis, KeyWillow did any comparative assessments of THESL's productivity relative to that of other comparable utilities. If such analysis was undertaken, please provide the results. If not, please state why not.
b) Please state whether or not THESL has quantitative means of tracking productivity gains throughout its operations. If yes, please state how it does this, if not, please state how THESL is developing the ability to track productivity gains throughout its operations in a programmatic manner.

RESPONSE:

a) No comparative assessment was done for reasons stated in the study on page 3, par 2.

b) The environment that THESL is operating in is changing rapidly. In addition, there are variable conditions within the work program. Consequently, traditional quantitative metrics prove to be misleading when comparing year-over-year changes to assess trends. It is for this reason that THESL has not produced these types of analyses.

INTERROGATORIES OF ONTARIO ENERGY BOARD STAFF

Rather, THESL's programmatic approach is to incorporate strong business discipline into its operation to achieve continuous improvement. This discipline is applied through the Management Control and Reporting System ("MCRS"), which establishes scorecards involving Key Performance Indicators ("KPIs"), sets targets and stretch goals for each, manages the program through regular KPI reviews to achieve short interval control, and rewards staff for performance against the targets/stretch goals. Through these techniques, THESL is able to improve its operations in all areas of the business over time.

INTERROGATORIES OF ONTARIO ENERGY BOARD STAFF

INTERROGATORY 4:

Reference(s): C1/ T4/ S1, App. B, p.5

When discussing its financial projections for its application, THESL provides a projected CPI rate for 2010 of 2.3%, which is stated as provided by the Conference Board of Canada.

a) Please confirm that this number came from page 4 of the Conference Board of Canada report "Economic Insights Into 27 Canadian Metropolitan Economies" from Spring 2009 included as Exhibit C1, Tab 4, Schedule 2, Appendix A.

b) Please state whether or not this is the most recent version of this report and, if not, please provide the most recent version.

RESPONSE:

a) Confirmed.

b) The latest available version of the Conference Board of Canada Metropolitan report at this point is from Autumn 2009. It is provided as Appendix A.

Based on the most recent report, the projected CPI rate for 2010 is 2.4%.

Based on the numbers from the most recent report Table 1 in Exhibit C1, Tab 4, Schedule 2 will look as follows:

INTERROGATORIES OF ONTARIO ENERGY BOARD STAFF

Table 1: Toronto Economic Indicators

	GDP Growth (%)	Consumer Price Index Growth (%)	Population Growth (%)	Employment Growth (%)	Unemployment Rate (%)	Retail Sales Growth (%)	Housing Starts (000s)
2006	3.0	1.6	2.1	1.4	6.6	3.2	37,080
2007	2.8	1.9	1.8	2.3	6.8	5.3	33,293
2008	0.3	2.4	1.8	1.9	6.9	4.2	42,212
2009	-2.7	0.9	1.8	-1.1	9.3	-5.7	23,092
2010	3.2	2.4	1.9	1.9	9.6	4.4	29,606

Source: Conference Board of Canada, August 2009

The Conference Board of Canada
Insights You Can Count On

Toronto Hydro-Electric System Limited
EB-2009-0139
Exhibit R1
Tab 1
Schedule 4
Appendix A
Filed: 2009 Nov 30
(24 pages)

Metropolitan Outlook 1 Autumn 2009

Economic Insights Into 27 Canadian Metropolitan Economies

ECONOMIC PERFORMANCE AND TRENDS

Metropolitan Outlook 1: Economic Insights Into 27 Canadian Metropolitan Economies
by *Mario Lefebvre, Alan Arcand, Greg Sutherland, Maxim Armstrong, Robin Wiebe,* and *Jane McIntyre*

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Forecast completed Aug. 7, 2009.
Based on Jun. 1, 2009, Canadian Economic Accounts.
Published in Canada
ISSN 1481-0247 • Agreement No. 40063028
*Incorporated as AERIC Inc.

This Issue

Book 1 covers Halifax, Québec City, Montréal, Ottawa–Gatineau, Toronto, Hamilton, Winnipeg, Regina, Saskatoon, Calgary, Edmonton, Vancouver, and Victoria.

Book 2 deals with St. John's, Saint John, Saguenay, Trois-Rivières, Sherbrooke, Kingston, Oshawa, St. Catharines–Niagara, Kitchener, London, Windsor, Greater Sudbury, Thunder Bay, and Abbotsford.

This publication is available through the Internet at www.conferenceboard.ca/edata.htm. For more information about the forecast, please contact our Information Specialists at 613-526-3090 ext. 444 or e-mail metro@conferenceboard.ca.

Contents

Highlights

- **Toronto**'s economy will shrink by 2.7 per cent this year, pulled down by the effects of the global recession.

Map

The census metropolitan areas (CMAs) are composed (defined by Statistics Canada) of the main city and the surrounding municipalities, towns, townships, villages, and parishes. The map shows the position of the CMA relative to other CMAs within the province.

Thumbs Up (Thumbs Down)

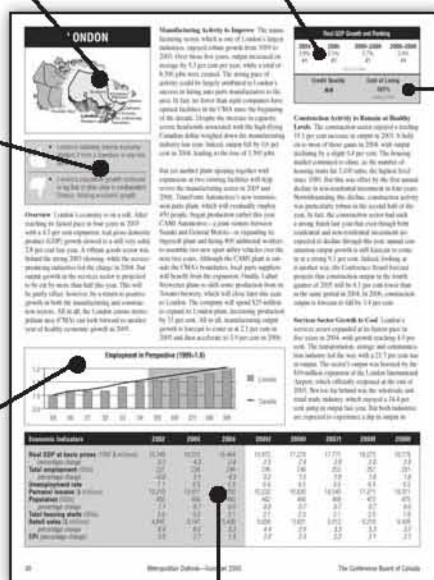
A thumbs up (down) indicates a favourable (unfavourable) element/event that has occurred within the census metropolitan area or that will certainly occur in the near future. It can also indicate a positive (negative) economic climate within the CMA.

Employment in Perspective

Using a base year (2002, for example) as a benchmark, this graph plots total employment growth against time. The shaded area of the graph represents the forecast horizon, and the forecast years are marked by the letter "f." The value 1.0 is given to the base year, and each subsequent year is used as a comparison; hence, the growth is clearly schemed. For analytical purposes, employment in perspective is shown with metropolitan and Canadian data. Canadian employment growth is represented by a line graph, while CMA employment growth is depicted by a bar graph.

Real GDP Growth and Ranking

The table displays four GDP growth rates: the last historical year, the current forecast year, the rest of the forecast period, and finally, a 10-year period comprising both historical and forecast data. Below each growth rate is a ranking that shows how the CMA fares against the other census metropolitan areas featured in the current edition of the *Metropolitan Outlook*.



Credit Quality

The credit rating is a current opinion (e.g., Dominion Bond Rating Service or Standard & Poor's) of the city's overall financial capacity (its creditworthiness) to pay its financial obligations. The rating applies to one of the individual cities within the CMA.

Debt Rating Service Scales

Dominion Bond Rating Service

Highest credit quality	AAA
Superior credit quality	AA
Satisfactory credit quality	A
Adequate credit quality	BBB
Speculative	BB
Highly speculative	B
Very highly speculative	CCC

Standard & Poor's

Highest quality	AAA™
Very good quality	AA
Good quality	A
Medium quality	BBB
Lower medium quality	BB
Poor quality	B
Speculative quality	C
Default	D
Rating suspended	Suspended

Cost of Living

Here the cost of living is shown as a ratio comparing the consumer price index (CPI) level of the CMA and that of Canada.

Economic Indicators

Industrial Classification

Statistics Canada compiles data on gross domestic product and employment following the North American Industrial Classification System (NAICS). Within this system, two aggregate sectors exist—goods and services—each of which is subdivided into industrial sectors based on major type of production activity. The goods-producing sector includes the primary, manufacturing, construction, and utilities industries, whereas the services sector aggregates transportation and communication; wholesale and retail trade; finance, insurance, and real estate; commercial services; non-commercial services; public administration; and defence.

Real GDP at Basic Prices

Gross domestic product at the CMA level is calculated using a weighted share of employment in both the CMA and the province and in provincial GDP. Hence, we are making the hypothesis that productivity is constant within an industry in different parts of a province. Total GDP is estimated by summing all the industrial GDP values. Values are posted in units of 2002 millions of dollars; hence, inflation effects are eliminated.

Total Employment

Total employment is the sum of employment in all industries. Data are presented in units of thousands, and an annual percentage growth value is also provided.

Unemployment Rate

The unemployment rate is the ratio of the number of unemployed workers to the total labour force.

Personal Income Per Capita

Personal income per capita is the sum of all revenues (wages, dividends, self-employment, etc.) received in a year. Data are in millions of dollars and not corrected for inflation (current dollars).

Population

The population data include inhabitants of all municipalities that make up the CMA.

Total Housing Starts

Total housing starts represent the sum of multiple and single housing construction starts. Multiple housing includes any type of building that can lodge more than one household. Examples: apartment complex, condominium, duplex, and triplex.

Retail Sales

Retail sales are quoted in units of millions of dollars and are not adjusted for inflation (current dollars).

Consumer Price Index (CPI)

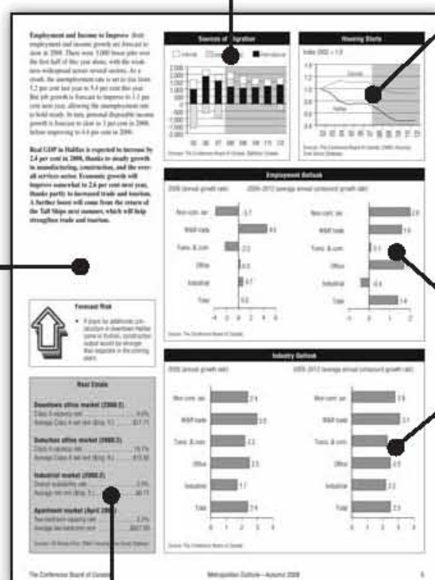
This index measures the cost of living for a typical urban family. It is composed of several goods priced after taxes. A benchmark year (1992, for example) is given the value 1.0. A value of 1.11 in 1999 is then interpreted as a growth of 11 per cent in the CPI between 1992 and 1999. Annual percentage growth rates are posted in italics below the CPI values.

Sources of Migration

Statistics Canada collects data for three types of population migration patterns: intercity, interprovincial, and international. Intercity migration is defined as the flow of population moving out of or into the metropolitan area to or from other cities in the province. Interprovincial migration represents population movements between the metropolitan area and other Canadian provinces, excluding the province in which the metropolitan area lies. International migration is the population movement between other countries and the metropolitan area. The graph plots the net values for the three demographic variables. The values can be read by matching the borderline of the bar to the left scale.

Housing Starts

The graph demonstrates the growth in housing starts over a period of time. The base year (for example, 2002) is given the value 1.0. Hence, the following yearly data represent the growth value in comparison with 2002. For example, the value 1.2 means that housing starts have increased by 20 per cent since 2002. Two lines are shown in the graph, one for the metropolitan area and one for Canada.



Forecast Risk

To gauge the likelihood of the economic forecast unfolding, we indicate whether there is an upside or downside risk. As indicated by the arrow, the overall forecast is conditional on key assumptions that may boost or dampen the outlook.

Employment Outlook and Industry Outlook

Employment growth percentages for five specific sectors are shown for the current year and for an average yearly value over the next four years. The office sector is defined by these industries: finance, insurance, and real estate (FIRE); commercial services; and public administration. The industrial sector includes the primary, manufacturing, construction, and utilities industries.

Real Estate

Depending on the availability of data, real estate information may include:

Downtown Office Market
The vacancy rate is the percentage of units available to lease in the CMA’s downtown core. The average lease rate is quoted per square foot in a downtown Class A location.

Suburban Office Market
The vacancy rate is the percentage of units available to lease in the CMA’s suburban areas. The average lease rate is quoted per square foot in a suburban Class A location.

Retail Market—Shopping Centre
The retail market consists of shopping centres, department stores, supermarkets, convenience stores, and power centres. The average lease rate is quoted per square foot in a prime street-front location.

Industrial Market
The industrial market consists of building units or assets devoted to production. The vacancy rate is the percentage of units available to lease, while the overall availability rate is the percentage of units available for sale. Average net rents or land values are quoted for the CMA’s most active land markets.

New Housing Market
Absorptions refer to the number of newly completed housing units that are sold or rented. Growth in absorptions or prices refers to the percentage change from the previous year.

Resale Housing Market
Unit sales are the number of existing homes sold on the multiple listings service (MLS). Growth in sales or prices refers to the percentage change from the previous year.

Apartment Market
The apartment market consists of building units devoted to residential dwellings. Average rents are quoted for a two-bedroom apartment.

Comparative Employment
Employment is disaggregated into five sectors: industrial; office; transportation and communication; wholesale and retail trade; and non-commercial services. This table shows the share of each employment component relative to the total.

Dominant Industries
Using the North American Industrial Classification System (NAICS), this table presents the most important industries for the CMA, ranked by employment. Industrial disaggregation is done at the four-digit level. The number of employees is quoted in units of thousands.

Large Employers
The Conference Board of Canada lists the CMA's major employers in the private and institutional sectors. These are not necessarily the largest employers, but taken together, they portray the metro job market.

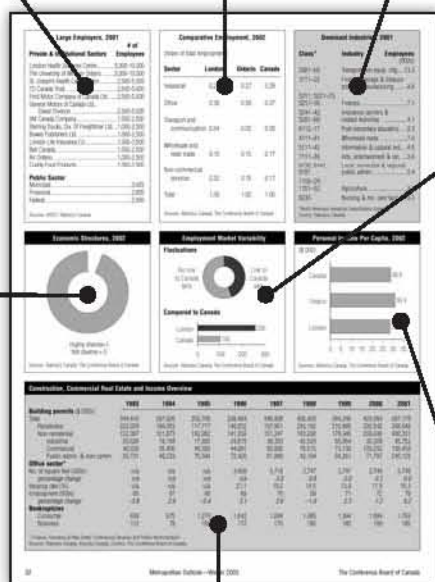
Employment Market Variability

Fluctuations
Fluctuation linked to Canada is an indication of the degree of correlation between changes in employment in the CMA and changes in employment in Canada between 1987 and the current year.

Fluctuation not linked to Canada is an indication of the degree of correlation between changes in employment in the CMA and changes in factors other than employment changes in Canada.

Compared to Canada
This bar chart represents the ratio of the standard deviation of total employment growth in the CMA to the standard deviation of total employment growth in Canada. The interpretation of this ratio is that the higher the number on the bar chart, the more volatile the labour market in the CMA relative to Canada.

Economic Structure
Canada is set as the benchmark for economic diversity. It is proposed that the Canadian economy is well diversified; hence, a comparison can be made between the CMAs and the Canadian economy. The value 1 is given to a metropolitan area that has the same industrial structure as Canada. A value of 0 means that the CMA has a totally different economic structure and thus implicitly lacks diversity.



Personal Income Per Capita
Personal income per capita is presented at the CMA, provincial and national levels. The information is presented in thousands of current (nominal) dollars.

Construction, Commercial Real Estate, and Income Overview

Building Permits
Historical data are in units of thousands for the number of building permits issued and are presented on a disaggregated level. Total building permits can be split into two main categories: residential and non-residential. Furthermore, the non-residential sector is divided into three sub-components: industrial; commercial and public administration; and non-commercial.

Office Sector
The total CMA office sector is quoted in units of thousands of square feet. This value evolves over time, and an annual growth percentage value is listed. The vacancy rate measures the amount of physically vacant space as a percentage of total inventory. Employment in thousands of units for the office sector is also quoted. The office sector is defined by these industries: finance, insurance, and real estate (FIRE); commercial services; and public administration.

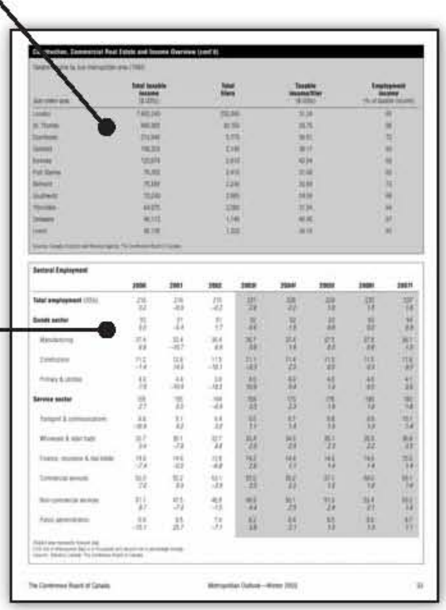
Bankruptcies
Business and consumer bankruptcy figures are available from Industry Canada.

Taxable Income by Sub-Metropolitan Area

The latest data available from Revenue Canada have been used to compile the total taxable income for sub-metropolitan areas, in units of thousands of dollars, The average taxable income per filer is calculated according to the number of people who file a tax report. Furthermore, the portion of taxable income that comes from employment income is highlighted.

Sectoral Employment

The most important industries for employment are listed, based on NAICS data. Industrial disaggregation is done at the four-digit level. The number of employees is quoted in units of thousands.



GLOSSARY OF ECONOMIC TERMS

Gross domestic product (GDP): A measure of the overall economic activity (value of goods and services produced) within an economy.

GDP at market prices: Represents the value of GDP as paid by final consumers; excludes subsidies but includes indirect taxes.

GDP at basic prices: Equivalent to GDP at market prices plus subsidies (product related) and minus indirect taxes (property and payroll but not sales taxes). It measures the value of producers' output. GDP at basic prices replaced GDP at factor cost, which was discontinued in January 2002.

Real* versus *nominal dollars: Real dollar economic measures such as GDP adjust for price changes and measure activity in a base year (e.g., 2002 $). Year-to-year changes in real or constant dollars reflect changes in quantities produced. Nominal dollar measures reflect quantities produced in prevailing prices (e.g., $ 000s). Year-to-year changes in nominal or current dollars reflect changes in both quantity and market prices.

Inflation: A sustained rise in the average level of all prices. The Consumer Price Index is one measure of inflation and is used as a proxy for inflation at the urban level.

Labour force: The total number of persons employed in both civilian and military jobs, plus the number of persons who are unemployed.

Participation rate: The total labour force expressed as a percentage of the population aged 15 years and over.

Canadian Census Metropolitan Areas

St. John's
Conception Bay South T
Portugal Cove-St. Philip's T
Pouch Cove T
Flatrock T
Torbay T
Logy Bay-Middle Cove-Outer Cove T
Bauline T
Paradise T
St. John's C
Mount Pearl C
Petty Harbour-Maddox Cove T
Bay Bulls T
Witless Bay T

Halifax
Cole Harbour 30 R
Shubenacadie 13 R
Halifax RGM
Sheet Harbour 36 R

Saint John
Saint Martins PAR
St. Martins VL
Simonds PAR
Saint John C
Musquash PAR
Lepreau PAR
Petersville PAR
Upham PAR
Hampton PAR
Hampton T
Rothesay PAR
Westfield PAR
Kingston PAR
Grand Bay–Westfield T
Greenwich PAR
Rothesay T
Quispamsis T

Saguenay
Saint-Fulgence M
La Baie V
Laterrière V
Chicoutimi V
Tremblay CT
Saint-Honoré M
Shipshaw M
Jonquière V
Lac-Kénogami M
Larouche M

Québec
Beaumont M
Saint-François P
Sainte-Famille P
Saint-Jean P
Saint-Laurent-de-l'Île-d'Orléans M
Saint-Pierre-de-l'Île-d'Orléans M
Sainte-Pétronille VL
Château-Richer V
L'Ange-Gardien P
Boischatel M
Sainte-Catherine-de-la-Jacques-Cartier V
Fossambault-sur-le-Lac V
Lac-Saint-Joseph V
Shannon M
Saint-Gabriel-de-Valcartier M
Lac-Delage V
Stoneham-et-Tewkesbury CU
Lac-Beauport M
Sainte-Brigitte-de-Laval M
Beauport V
Vanier V
Notre-Dame-des-Anges P
Sillery V
Québec V
Charlesbourg V
Saint-Émile V
Lac-Saint-Charles V
Loretteville V
Val-Bélair V
L'Ancienne-Lorette V
Sainte-Foy V
Cap-Rouge V
Saint-Augustin-de-Desmaures M
Wendake R
Pintendre M
Saint-Joseph-de-la-Pointe-de-Lévy P
Lévis V
Saint-Lambert-de-Lauzon P
Saint-Étienne-de-Lauzon M
Sainte-Hélène-de-Breakeyville P
Saint-Jean-Chrysostome V
Saint-Romuald V
Charny V
Saint-Rédempteur V
Saint-Nicolas V

Sherbrooke
Ascot Corner M
Stoke M
Saint-Denis-de-Brompton P
Waterville V
Lennoxville V
Ascot M
Fleurimont V
Bromptonville V
Sherbrooke V
Rock Forest V
Deauville M
Saint-Élie-d'Orford M
Compton M
North Hatley VL
Hatley CT

Trois-Rivières
Champlain M
Saint-Maurice P
Sainte-Marthe-du-Cap V
Cap-de-la-Madeleine V
Saint-Louis-de-France V
Trois-Rivières V
Trois-Rivières-Ouest V
Pointe-du-Lac M
Bécancour V
Wôlinak 11 R

Montréal
Lavaltrie VL
Saint-Antoine-de-Lavaltrie P
Richelieu V
Saint-Mathias-sur-Richelieu M
Chambly V
Carignan V
Saint-Bruno-de-Montarville V
Saint-Basile-le-Grand V
McMasterville M
Otterburn Park V
Mont-Saint-Hilaire V
Beloeil V
Saint-Mathieu-de-Beloeil M
Brossard V
Saint-Lambert V
Greenfield Park V
Saint-Hubert V
LeMoyne V
Longueuil V
Boucherville V
Sainte-Julie V
Saint-Amable M
Varennes V
Charlemagne V
Le Gardeur V
Repentigny V
Saint-Sulpice P
L'Assomption V
Lachenaie V
Terrebonne V
Mascouche V
La Plaine V
Laval V
Montréal-Est V
Anjou V
Saint-Léonard V
Montréal-Nord V
Montréal V
Westmount V
Verdun V
LaSalle V
Montréal-Ouest V
Côte-Saint-Luc C
Lachine V
Hampstead V
Outremont V
Mont-Royal V
Saint-Laurent V
Dorval C
L'Île-Dorval V
Pointe-Claire V
Kirkland V
Beaconsfield V
Baie-d'Urfé V
Sainte-Anne-de-Bellevue V
Senneville VL
Pierrefonds V
Sainte-Geneviève V
Dollard-des-Ormeaux V
Roxboro V
L'Île-Bizard V
Saint-Mathieu M
Saint-Philippe M
La Prairie V
Candiac V
Delson V
Sainte-Catherine V
Saint-Constant V
Saint-Isidore P
Mercier V
Châteauguay V
Léry V
Kahnawake 14 R
Maple Grove V

Beauharnois V
Melocheville VL
Les Cèdres M
Pointe-des-Cascades VL
L'Île-Perrot V
Notre-Dame-de-l'Île-Perrot M
Pincourt V
Terrasse-Vaudreuil M
Vaudreuil-Dorion V
Vaudreuil-sur-le-Lac VL
L'Île-Cadieux V
Hudson V
Saint-Lazare P
Saint-Eustache V
Deux-Montagnes V
Sainte-Marthe-sur-le-Lac V
Pointe-Calumet M
Saint-Joseph-du-Lac M
Oka M
Saint-Placide M
Kanesatake R
Boisbriand V
Sainte-Thérèse V
Blainville V
Rosemère V
Lorraine V
Bois-des-Filion V
Sainte-Anne-des-Plaines V
Mirabel V
Saint-Colomban P
Bellefeuille V
Saint-Jérôme V
Saint-Antoine V
Lafontaine V
Gore CT

Ottawa–Gatineau
Buckingham V
Masson-Angers V
Gatineau V
Hull V
Aylmer V
Val-des-Monts M
Cantley M
Chelsea M
Pontiac M
La Pêche M
Clarence-Rockland C
Russell TP
Ottawa C

Kingston
Frontenac Islands TP
Kingston C
South Frontenac TP
Loyalist TP

Oshawa
Whitby T
Oshawa C
Clarington T

Toronto
Pickering C
Ajax T
Uxbridge TP
Vaughan C
Markham T
Richmond Hill T
Whitchurch-Stouffville T
Aurora T
Newmarket T
King TP
East Gwillimbury T
Georgina T
Chippewas of Georgina Island First Nation R
Toronto C
Mississauga C
Brampton C
Caledon T
Mono T
Orangeville T
Oakville T
Milton T
Halton Hills T
New Tecumseth T
Bradford West Gwillimbury T

Hamilton
Burlington C
Hamilton C
Grimsby T

St. Catharines–Niagara
Fort Erie T
Port Colborne C
Wainfleet TP
Pelham T
Welland C
Thorold C
Niagara Falls C
Niagara-on-the-Lake T
St. Catharines C
Lincoln T

Kitchener
North Dumfries TP
Cambridge C
Kitchener C
Waterloo C
Woolwich TP

London
Central Elgin TP
St. Thomas C
Southwold TP
Strathroy-Caradoc TP
Thames Centre TP
Middlesex Centre TP
London C

Windsor
Amherstburg T
LaSalle T
Windsor C
Tecumseh T
Lakeshore T

Greater Sudbury
Whitefish Lake 6 R
Greater Sudbury C
Wahnapitei 11 R

Thunder Bay
Neebing TP
Fort William 52 R
Thunder Bay C
Oliver Paipoonge TP
Gillies TP
O'Connor TP
Conmee TP
Shuniah TP

Winnipeg
Taché RM
Ritchot RM
St. François Xavier RM
Winnipeg C
Headingley RM
Springfield RM
East St. Paul RM
West St. Paul RM
St. Clements RM
Brokenhead 4 R
Rosser RM

Regina
Pense No. 160 RM
Belle Plaine VL
Pense VL
Sherwood No. 159 RM
Regina C
Grand Coulee VL
Edenwold No. 158 RM
White City T
Pilot Butte T
Balgonie T
Edenwold VL
Lumsden No. 189 RM
Disley VL
Buena Vista VL
Lumsden T
Lumsden Beach RV
Regina Beach T

Saskatoon
Thode RV
Dundurn No. 314 RM
Dundurn T
Shields RV
Corman Park No. 344 RM
Saskatoon C
Langham T
Warman T
Blucher No. 343 RM
Martensville T
Bradwell VL
Allan T
Dalmeny T
Elstow VL
Osler T
Colonsay No. 342 RM
Clavet VL
Meacham VL
Colonsay T
White Cap 94 R
Vanscoy No. 345 RM
Delisle T
Vanscoy VL
Asquith T

Calgary
Rocky View No. 44 MD
Calgary C
Chestermere T

Canadian Census Metropolitan Areas

Cochrane T
Airdrie C
Irricana VL
Beiseker VL
Crossfield T
Tsuu T'ina Nation 145 R

Edmonton
Bruderheim T
Leduc County CM
Beaumont T
New Sarepta VL
Leduc C
Devon T
Calmar T
Sundance Beach SV
Thorsby VL
Itaska Beach SV
Golden Days SV
Warburg VL
Parkland County CM
Seba Beach SV
Betula Beach SV
Point Alison SV
Lakeview SV
Kapasiwin SV
Wabamun VL
Autumn Lake VL
Stony Plain T
Spruce Grove C
Strathcona County SM
Fort Saskatchewan C
Sturgeon County MD
Edmonton C
St. Albert C
Gibbons T
Redwater T
Bon Accord T
Morinville T
Legal T
Stony Plain 135 R
Alexander 134 R
Wabamun 133A R

Abbotsford
Abbotsford C
Mission DM
Fraser Valley H RDA
Upper Sumas 6 R
Matsqui Main 2 R

Vancouver
Langley DM
Langley C
Surrey C
White Rock C
Delta DM
Richmond C
Greater Vancouver A RDA
Vancouver C
Burnaby C
New Westminster C
Coquitlam C
Belcarra VL
Anmore VL
Port Coquitlam C
Port Moody C
North Vancouver DM
North Vancouver C
West Vancouver DM
Bowen Island IM
Lions Bay VL
Pitt Meadows DM
Maple Ridge DM
Semiahmoo R
Tsawwassen R
Musqueam 2 R
Coquitlam 2 R
Coquitlam 1 R
Burrard Inlet 3 R
Mission 1 R
Capilano 5 R
Barnston Island 3 R
Musqueam 4 R
Seymour Creek 2 R
Katzie 2 R
McMillan Island 6 R
Matsqui 4 R
Katzie 1 R
Langley 5 R
Whonnock 1 R

Victoria
North Saanich DM
Sidney T
Central Saanich DM
Saanich DM
Oak Bay DM
Victoria C
Esquimalt DM
Colwood C
Metchosin DM
Langford DM
View Royal T
Highlands DM
Sooke DM
Capital H RDA
Cole Bay 3 R
Union Bay 4 R
East Saanich 2 R
South Saanich 1 R
Becher Bay 1 R
Esquimalt R 10000
New Songhees 1A R
T'Sou-ke 1 R
T'Sou-ke 2 R

Abbreviations:
C = City
CM = County (Municipality)
CT = Canton (Municipalité de)
CU = Cantons unis (Municipalité de)
DM = District Municipality
IM = Island Municipality
M = Municipalité
MD = Municipal District
P = Paroisse (Municipalité de)
PAR = Parish
R = Indian Reserve
RDA = Regional District Electoral Area
RGM = Regional Municipality
RM = Rural Municipality
RV = Resort Village
SV = Summer Village
T = Town
TP = Township
V = Ville
VL = Village

Note: The 2001 census metropolitan areas reflect the agglomeration of several individual municipalities into one jurisdiction. For example, Halifax CMA now encompasses Halifax Regional Municipality, Cole Harbour, Shubenacadie, and Sheet Harbour. The Halifax Regional Municipality includes Bedford, Dartmouth, and Halifax, which were listed separately in the 1996 definition of the Halifax CMA.

In 2001, Statistics Canada increased the number of CMAs to 27. Abbotsford and Kingston were added.

Cross-City Comparison

Real GDP growth (per cent) 2008		Real GDP growth (per cent) 2009f		Real GDP growth (per cent) 2010f–2013f	
Saskatoon	5.9	Halifax	1.4	Toronto	4.2
Regina	4.1	Winnipeg	0.8	Calgary	4.1
Halifax	2.8	Québec City	0.1	Edmonton	4.1
Winnipeg	2.6	Regina	–0.1	Vancouver	3.6
Québec City	2.1	Saskatoon	–0.3	Hamilton	3.4
Victoria	1.6	Ottawa–Gatineau	–0.5	Ottawa–Gatineau	3.2
Edmonton	1.3	Victoria	–1.0	Saskatoon	3.1
Montréal	1.1	Montréal	–1.0	Regina	2.9
Ottawa–Gatineau	0.8	Edmonton	–1.9	Winnipeg	2.9
Calgary	0.4	Calgary	–2.1	Montréal	2.8
Toronto	0.3	Vancouver	–2.6	Halifax	2.6
Vancouver	–0.1	Toronto	–2.7	Victoria	2.5
Hamilton	–1.3	Hamilton	–4.1	Québec City	2.4

CANADA

- The recession has spread all the way to Canadian households, with consumer spending forecast to contract in 2009.
- Exporters are still struggling and will have to hope that next year brings better results.

Overview It's now official—Canada's economy entered recession in the fourth quarter of 2008. In retrospect, however, various sectors of the Canadian economy have been in difficulty since U.S. real estate markets began unwinding back in late 2005. The steep and steady erosion in U.S. home values has damaged U.S. household net worth and confidence, forcing consumers to step up their saving and hold back on spending. Canadian firms have been hit hard by the fallout. Exports of lumber and other construction material fell off sharply, and exports of autos and parts followed soon after, pounding Canada's auto industry. Overall, Canada's real gross domestic product is forecast to contract by 1.9 per cent this year. For next year, recovering commodity prices and growth in U.S. household spending will serve to bolster Canada's economy. Moreover, the full effect of government stimulus packages will further prop up the economy. Real GDP growth of 2.7 per cent is expected for 2010.

Exporters Hopeful for Next Year Battered and beaten, Canadian exporters of lumber and construction materials have now been through the worst of the current business cycle. U.S. housing starts averaged just 527,000 units (annualized) over the first half of 2009—far below demographic requirements estimated at between 1.3 million and 1.6 million units per year. New home construction can only come up from its current rock-bottom levels. Still, the recovery will be tenuous, and normal construction levels will not be reached again until late in the forecast horizon. The situation is similar for automakers. U.S. vehicle sales averaged annualized levels of less than 9.7 million units over the first six months of the year. This is well below normal scrappage rates of roughly 10 million to 12 million units per year. Overall, a modest recovery in U.S. residential construction and auto sales will help reverse the tide for Canadian exports. Export volumes are forecast to post growth of 2.8 per cent next year following a 14.2 per cent decline in 2009.

Household Spending on Pace to Contract With the U.S. recession spreading north, Canadian consumers have also tightened their purse strings. Households in Canada have been hit by the effects of falling equity values and home prices and of dwindling confidence. Moreover, employment losses are mounting. Between November and July, the Canadian economy shed 414,000 jobs. The effects on labour income will be further amplified by low wage gains and by a reduction in average hours worked as companies replace full-time workers with part-time staff. Despite muted inflation and tax cuts by various levels of government, real after-tax income is expected to shrink by 0.5 per cent this year. This will be a shock to Canadian consumers who, over the past six years, have grown accustomed to real disposable income growth averaging a handsome 3.7 per cent annually. As Canadians struggle to add to savings, real household spending is forecast to contract by 0.7 per cent this year.

A Positive Contribution From Government Spending For this year, the only positive contribution to Canada's domestic economy will come from the government sector. Federal and provincial governments have committed, in varying degrees, to strong infrastructure stimulus and other incentives to try to prop up the economy. Even as growth in direct program spending is moderating in light of prudent provincial budgets, and even though peak spending is not expected to occur until next year, the infrastructure stimulus will be timely. But when economic growth recovers, government deficits will be difficult to correct. The federal government has calculated that the combination of sustained spending and shrinking revenues will result in a $50-billion deficit in the current fiscal year. And while the federal situation is cause for serious concern, provincial governments as a whole are in even worse shape.

Stimulus packages the world over are starting to be felt during the second half of 2009. While infrastructure spending has been slow in coming and will peak only next year, it will still be timely. Economic growth in Canada is forecast to resume over the second half of 2009. Still, real GDP will contract by 1.9 per cent this year before recovering with growth of 2.7 per cent in 2010.

Forecast Risk

- While the global recovery will be helped along by the concerted efforts of policy makers, its strength will be muted over the next 18 months by the fragile pickup in U.S. consumer spending. Indeed, the U.S. economy needs to regain balance on many fronts. In addition to troubled real estate and financial markets, the U.S. economy still has underlying problems with respect to its large external trade deficit and its now huge budgetary deficit.

Real GDP Growth

2008	2009	2010–2013	2004–2013
0.4%	–1.9%	3.6%	2.4%

Credit Quality

AAA

Standard & Poor's

Economic Indicators	2006	2007	2008	2009f	2010f	2011f	2012f	2013f
Real GDP at basic prices (2002 $ millions)	1,283,419	1,315,907	1,321,360	1,295,922	1,330,595	1,377,911	1,434,981	1,490,051
percentage change	*2.9*	*2.5*	*0.4*	*–1.9*	*2.7*	*3.6*	*4.1*	*3.8*
Total employment (000s)	16,485	16,865	17,123	16,823	16,894	17,344	17,810	18,081
percentage change	*1.9*	*2.3*	*1.5*	*–1.8*	*0.4*	*2.7*	*2.7*	*1.5*
Unemployment rate	6.3	6.0	6.1	8.4	9.2	8.2	6.8	6.3
Personal income per capita	34,003	35,604	36,878	36,757	37,459	38,864	40,472	42,007
Population (000s)	32,532	32,882	33,260	33,607	33,931	34,275	34,631	35,001
percentage change	*1.0*	*1.1*	*1.2*	*1.0*	*1.0*	*1.0*	*1.0*	*1.1*
Single-family housing starts (000s)	121.3	118.9	93.2	68.7	87.2	101.4	104.1	100.6
Multi-family housing starts (000s)	106.1	109.4	117.9	66.6	77.5	92.3	97.2	97.6
Retail sales ($ millions)	389,485	412,037	426,047	408,349	422,165	446,908	477,544	505,223
percentage change	*6.4*	*5.8*	*3.4*	*–4.2*	*3.4*	*5.9*	*6.9*	*5.8*
CPI (2002 = 1.000)	1.091	1.114	1.141	1.150	1.180	1.209	1.237	1.262
percentage change	*2.0*	*2.1*	*2.4*	*0.8*	*2.6*	*2.5*	*2.3*	*2.0*

ONTARIO

- Despite unprecedented fiscal stimulus, a deteriorating international trade balance and worsening labour market conditions have left Ontario's economy in recession this year.
- Roughly 178,600 net jobs have been lost in Ontario since December last year—244,200 in full-time employment.

Overview Recession has become a four-letter word in Ontario's manufacturing heartland this year, after the province posted several quarters of negative growth in real gross domestic product. The province has been battered by the global recession. However, despite the litany of bad news stories about the virtual disappearance of new business investment, widespread full-time job losses, and automaker bankruptcies, some green shoots are finally emerging in the economic environment. Although real GDP is on pace to contract by 3.1 per cent in 2009, it is forecast to rebound by 3.2 per cent next year.

Public Stimulus: A Double-Edged Sword Public expenditures will be almost the only source of growth in Ontario's economy this year. In the near term, total program expenses of $27.4 billion over this year and next will cause government spending on goods and services to increase by 5.3 per cent in 2009 and a further 6.2 per cent next year. Unfortunately, this will also mean that Ontario's deficit is expected to soar to $14.1 billion in the 2009–10 fiscal year—the largest provincial deficit in history.

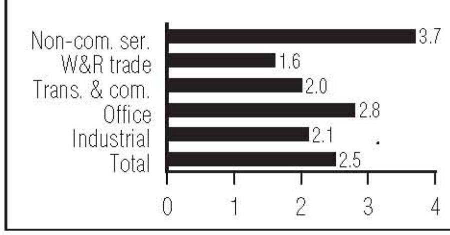
Household Sector Still in Limbo Since December 2008, Ontario's economy has shed 178,600 positions, with full-time employment down by 244,200. Job losses are set to ebb in the third quarter of 2009, with net gains forecast as early as the final quarter of this year. Workers who remain employed will see marginal gains in real wages, although the unemployment rate will average 9.2 per cent in 2009 and peak at 10.2 per cent in 2010. Disposable incomes are forecast to retreat modestly this year as labour markets loosen, but they will recover in 2010 as employment conditions stabilize. Accordingly, Ontario consumers have tightened their purse strings, cutting back on real spending by an anticipated 1.1 per cent in 2009.

Auto Sector Feeling the Pain Ontario's auto sector has arguably been the hardest hit by the financial crisis in the U.S., the ensuing pullback in consumer spending, and the added difficulty of a strong petro-loonie. U.S. sales of new motor vehicles averaged fewer than 9.7 million annualized units in the first half of 2009, even below typical scrappage rates of 10 million to 12 million units. Accordingly, real automotive exports are forecast to contract by 47.5 per cent this year. With both Chrysler and General Motors finalizing Chapter 11 bankruptcy transactions and U.S. consumer demand having hit bottom, the sector will recover at a double-digit pace in the medium term. However, that won't be enough to restore industry exports to pre-bankruptcy levels, and employment will trend below historical levels to reflect higher per-worker productivity as new plant investments are secured.

Real GDP in Ontario is expected to contract by 3.1 per cent in 2009, despite increased public spending. The fiscal stimulus program designed to help the province weather the global recession will not be enough to offset weak international trade, particularly in the auto sector. Employment losses and slower income growth are contributing to a weak consumer sector this year as well. But stronger growth worldwide in 2010 will help push Ontario's economy back up by 3.2 per cent next year.

Industry Outlook, 2009–2013

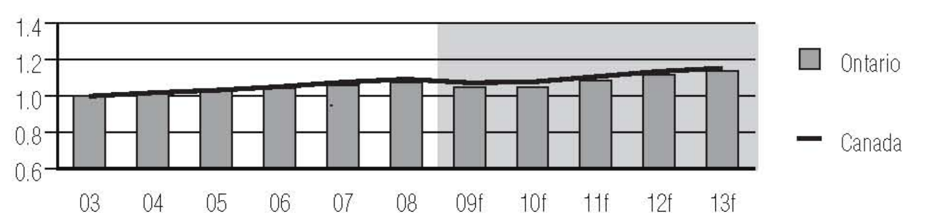
(average annual compound growth rate)



Forecast Risk

- Possible delays in either GM's or Chrysler's restructuring are a downside risk for Ontario's auto sector.

Employment in Perspective (2003 = 1.0)



Real GDP Growth

2008	2009	2010–2013	2004–2013
–0.2%	–3.1%	3.9%	2.2%

Credit Quality

AA

Standard & Poor's

Economic Indicators	2006	2007	2008	2009f	2010f	2011f	2012f	2013f
Real GDP at basic prices (2002 $ millions)	482,489	492,897	491,833	476,723	492,202	511,114	533,485	556,483
percentage change	*2.4*	*2.2*	*–0.2*	*–3.1*	*3.2*	*3.8*	*4.4*	*4.3*
Total employment (000s)	6,492	6,592	6,687	6,508	6,530	6,739	6,951	7,087
percentage change	*1.5*	*1.5*	*1.4*	*–2.7*	*0.3*	*3.2*	*3.1*	*2.0*
Unemployment rate	6.3	6.4	6.5	9.2	10.2	9.0	7.4	7.1
Personal income per capita	34,987	36,305	37,305	36,933	37,565	38,968	40,560	42,091
Population (000s)	12,645	12,775	12,910	13,025	13,162	13,327	13,504	13,693
percentage change	*1.1*	*1.0*	*1.1*	*0.9*	*1.1*	*1.3*	*1.3*	*1.4*
Single-family housing starts (000s)	38.3	37.9	31.1	22.2	32.2	40.5	43.2	42.2
Multi-family housing starts (000s)	35.1	30.2	44.0	26.1	32.2	41.3	45.4	46.3
Retail sales ($ millions)	140,808	146,252	151,390	145,864	151,273	161,027	172,677	183,459
percentage change	*4.1*	*3.9*	*3.5*	*–3.7*	*3.7*	*6.4*	*7.2*	*6.2*
CPI (2002 = 1.000)	1.088	1.108	1.133	1.141	1.168	1.201	1.228	1.253
percentage change	*1.8*	*1.8*	*2.3*	*0.7*	*2.4*	*2.8*	*2.3*	*2.0*

TORONTO

- The recession has sparked fear in consumers, leading to significant declines in wholesale and retail trade activity.
- Housing starts are forecast to fall by more than 45 per cent this year, with the decline evenly split between singles and multiples.

Overview Toronto's economy is expected to contract by 2.7 per cent in 2009, pulled down by the global recession. The goods sector will be hard hit, falling by 12 per cent. Manufacturing output is set to drop for the fourth year in a row this year, because of weaker demand both at home and abroad, while construction output will feel the pinch of lower residential and non-residential investment. At the same time, the services sector, the cornerstone of growth in the Toronto economy in recent years, is expected to rise by just 0.1 per cent. Despite decent growth in the finance, insurance, real estate, and public sectors, the overall services sector is being held back by a big drop in wholesale and retail trade. But with local and global conditions expected to improve in 2010, real gross domestic product in Toronto is forecast to rebound and post 3.2 per cent growth next year.

Manufacturing Sector Still Feeling the Pain
This year will mark the fourth annual decline in manufacturing output in Toronto, and the largest by far at –14.5 per cent. This weakness has led to thousands of manufacturing job losses in the region over the past few years. Indeed, since peaking in 2004, manufacturing employment has fallen by more than 130,000, a nearly 30 per cent drop. While the sector was initially hard hit by the rapid rise in the Canadian dollar, making exports of goods manufactured here more expensive, its larger problem over the past year has been the global downturn, which has reduced demand in Canada and worldwide. But with GDP growth in both Canada and the U.S. expected to pick up in 2010, Toronto's manufacturing sector will finally begin to turn around next year. Still, although 3.5 per cent output growth is forecast for 2010, and a 5.6 per cent annual average increase is expected over the medium term, manufacturing output will remain about 9 per cent below 2000 levels in 2013.

Housing Takes a Tumble Even though overall economic growth had already started to deteriorate last year, housing starts still climbed 26.8 per cent. But that number was almost entirely due to a huge increase in multiple-unit housing starts in the first quarter of the year, brought about by the construction of a number of new high-rise buildings in the downtown core, many of which had been pre-sold under better market conditions. Indeed, by the fourth quarter, starts had already fallen back 20 per cent from their first-quarter levels (at annualized rates). Housing starts have since dropped another 55 per cent over the first half of 2009. While activity is set to improve over the last half of this year, starts are still expected to fall by a whopping 45.3 per cent in 2009 as a whole. Specifically, construction is expected to begin on only 23,100 new homes this year, the fewest since 1998. And despite the pickup in sales in recent weeks, it was recently announced that a planned 80-storey condominium and hotel project at 1 Bloor is now in doubt because the developer has put the land up for sale. But as the economy starts to regain its footing in 2010, the new housing market will also improve, with starts projected to rise by 28.2 per cent next year. Starts are forecast to remain on an upward trend through the medium term, moving more in line with demographic requirements. By the end of the forecast period, housing starts will once again have reached pre-recession levels, hitting 44,500 units in 2013.

While non-residential construction is also forecast to slow this year, there are still several large projects under way, including the RBC Centre and the TELUS tower. Other major projects in the downtown core include the Bell Lightbox, Trump Tower, Maple Leaf Square, and the Shangri-La hotel and condominium high-rise. Additional planned projects such as the second and third towers of the Bay-Adelaide Centre will keep non-residential construction humming through the medium term as well. In total, real construction output is expected to fall by 6.5 per cent in 2009, before increasing by 3.5 per cent next year.

Real GDP Growth and Ranking

2008	2009	2010–2013	2004–2013
0.3%	–2.7%	4.2%	2.6%
#11	#12	#1	#7

Out of 13 CMAs

Credit Quality	Cost of Living
AA	*99%*
City of Toronto Standard & Poor's	Canada = 100%

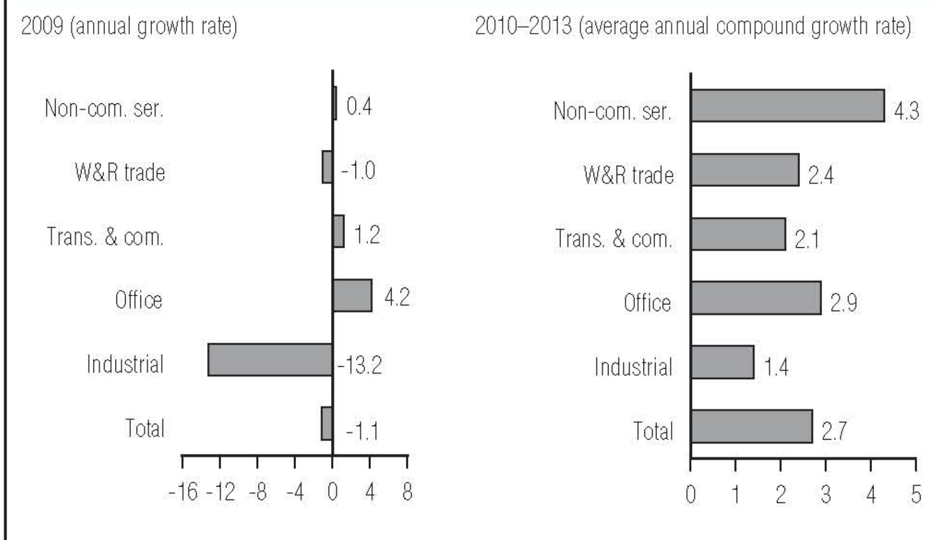
Economic Indicators	2006	2007	2008	2009f	2010f	2011f	2012f	2013f
Real GDP at basic prices (2002 $ millions)	214,456	220,482	221,182	215,259	222,092	232,008	242,920	254,175
percentage change	*3.0*	*2.8*	*0.3*	*–2.7*	*3.2*	*4.5*	*4.7*	*4.6*
Total employment (000s)	2,802	2,866	2,921	2,890	2,945	3,032	3,141	3,218
percentage change	*1.4*	*2.3*	*1.9*	*–1.1*	*1.9*	*3.0*	*3.6*	*2.4*
Unemployment rate	6.6	6.8	6.9	9.3	9.6	9.2	7.8	7.4
Personal income per capita	37,226	38,166	39,037	38,793	39,645	40,974	42,603	44,113
percentage change	*4.6*	*2.5*	*2.3*	*–0.6*	*2.2*	*3.4*	*4.0*	*3.5*
Population (000s)	5,337	5,432	5,531	5,628	5,733	5,850	5,975	6,108
percentage change	*2.1*	*1.8*	*1.8*	*1.8*	*1.9*	*2.0*	*2.1*	*2.2*
Total housing starts	37,080	33,293	42,212	23,092	29,606	37,791	42,795	44,497
Retail sales ($ millions)	55,078	57,984	60,423	56,988	59,481	63,764	68,669	73,250
percentage change	*3.2*	*5.3*	*4.2*	*–5.7*	*4.4*	*7.2*	*7.7*	*6.7*
CPI (2002 = 1.0)	1.084	1.105	1.131	1.141	1.169	1.201	1.229	1.254
percentage change	*1.6*	*1.9*	*2.4*	*0.9*	*2.4*	*2.8*	*2.3*	*2.0*

Shaded area represents forecast data.
Sources: Statistics Canada; CMHC Housing Time Series Database; The Conference Board of Canada.

Services Sector Growth Halted by Weak Trade
Weakened consumer confidence wreaked havoc on Toronto's wholesale and retail trade output from the final quarter of 2008 and through the first half of this year. As a result, wholesale and retail trade output is forecast to drop a substantial 9 per cent in 2009, limiting growth in overall services sector output to just 0.1 per cent. What strength there is in the services sector is coming mainly from the finance, insurance, and real estate sector and the public sector. Finance, insurance, and real estate output is expected to increase by 2.1 per cent, despite the battered housing market. Meanwhile, non-commerical services and public administration output are set to rise by 3.2 per cent and 3.4 per cent, respectively. Improved economic conditions in 2010 will allow for more widespread growth in the services sector, leading to a 3.1 per cent increase next year.

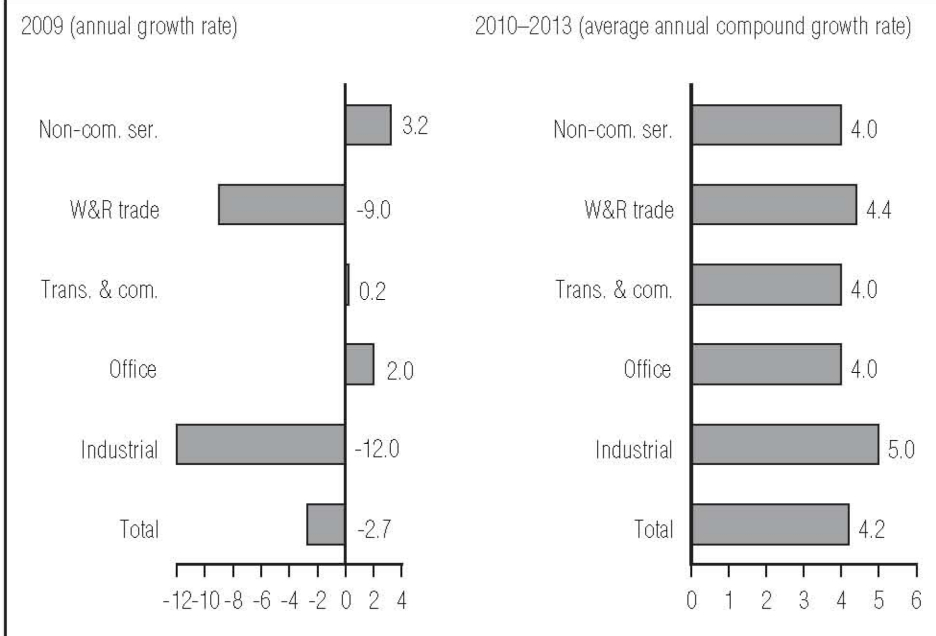
Toronto's real GDP is expected to fall by 2.7 per cent this year as the global recession lowers demand, pushing down output in manufacturing, construction, and wholesale and retail trade. Better economic conditions in 2010 will allow real GDP to bounce back by 3.2 per cent next year.

Employment Outlook

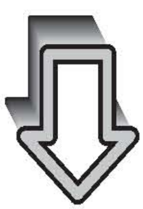


Source: The Conference Board of Canada.

Industry Outlook



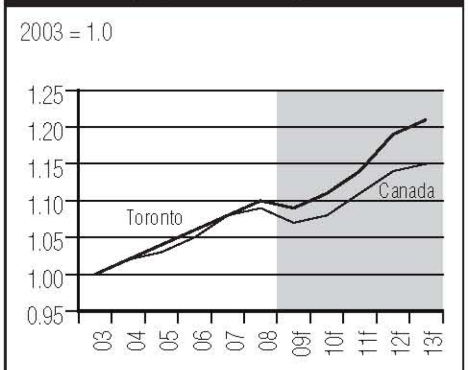
Source: The Conference Board of Canada.



Forecast Risk

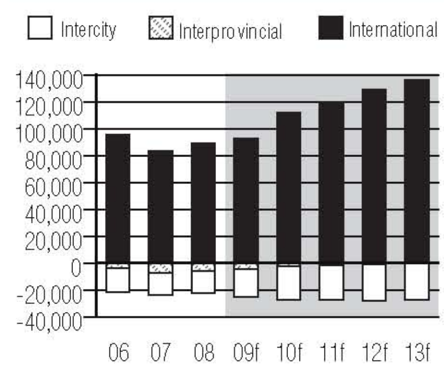
- Delays in large residential and non-residential construction projects due to the recent economic downturn would lead to lower near-term growth in construction output.

Employment in Perspective



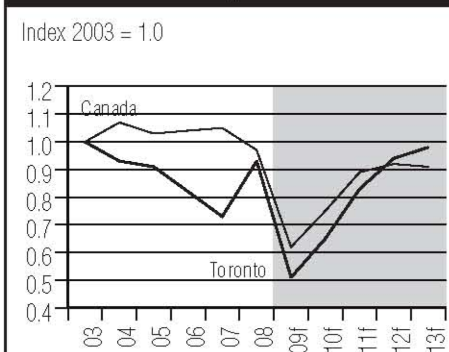
Sources: Statistics Canada; The Conference Board of Canada.

Sources of Migration



Sources: Statistics Canada; The Conference Board of Canada.

Housing Starts



Sources: The Conference Board of Canada; CMHC Housing Time Series Database.

Real Estate

Downtown office market (2008:4)

Class A vacancy rate	4.5%
Average Class A net rent ($/sq. ft.)	$24.74

Suburban office market (2008:4)

Class A vacancy rate	8.8%
Average Class A net rent ($/sq. ft.)	$16.14

Industrial market (2008:4)

Overall availability rate	5.3%
Average net rent ($/sq. ft.)	$5.22

Apartment market (April 2009)

Two-bedroom vacancy rate	2.4%
Average two-bedroom rent	$1,093.00

Sources: CB Richard Ellis; CMHC Housing Time Series Database.

Comparative Employment, 2008

(share of total employment)

Sector	Toronto	Ontario	Canada
Industrial	0.21	0.23	0.23
Office	0.39	0.36	0.35
Transport and communication	0.09	0.08	0.07
Wholesale and retail trade	0.16	0.15	0.16
Non-commercial services	0.15	0.18	0.18
Total	1.00	1.00	1.00

Sources: Statistics Canada; The Conference Board of Canada.

Dominant Industries, 2008

Class*	Industry	Employees (000s)
4411–4543	Retail trade	328.6
2311–29	Construction	183.4
5211, 5221–23, 5231–39	Finance	162.2
7221–24	Food & beverage services	133.0
4111–91	Wholesale trade	125.3
6111	Primary & sec. schools	124.5
5111–42	Info. & cultural ind.	99.0
5511, 5611–12, 5615–17, 5619 5621–29	Other management & administrative services	93.1
6211–19	Ambulatory health care serv.	92.4
5415	Computer sys. design serv.	92.3

*North American Industrial Classification System
Source: Statistics Canada.

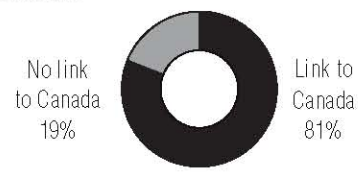
Economic Structure, 2008

Highly diverse = 1
Not diverse = 0

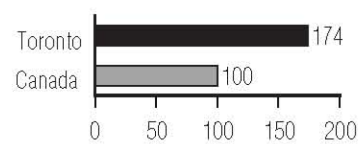
Sources: Statistics Canada; The Conference Board of Canada.

Employment Market Variability

Fluctuations



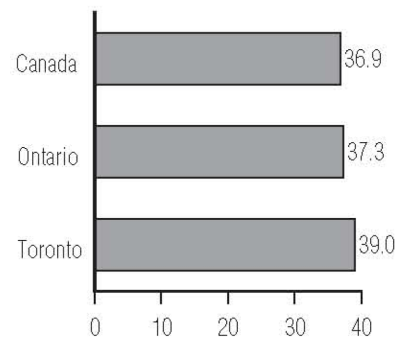
Compared to Canada



Sources: Statistics Canada; The Conference Board of Canada.

Personal Income Per Capita, 2008

($ 000s)



Sources: Statistics Canada; The Conference Board of Canada.

Construction, Commercial Real Estate, and Income Overview

	2000	2001	2002	2003	2004	2005	2006	2007	2008
Building permits ($ 000s)									
Total	8,539,456	9,534,905	10,525,171	11,642,394	12,148,850	11,421,317	11,022,330	13,291,434	12,234,166
Residential	5,291,578	5,999,354	7,256,279	7,417,823	7,650,693	7,496,343	7,120,759	8,106,246	7,112,561
Non-residential	3,247,878	3,535,551	3,268,892	4,224,571	4,498,157	3,924,974	3,901,571	5,185,188	5,121,605
Industrial	801,588	663,585	561,471	963,349	911,916	679,156	725,652	915,017	728,565
Commercial	1,853,542	1,805,487	1,501,855	1,883,140	2,198,456	2,186,671	2,386,161	3,114,836	3,214,770
Public admin. & non-comm.	592,748	1,066,479	1,205,566	1,378,082	1,387,785	1,059,147	789,758	1,155,335	1,178,270
Office sector*									
No. of square feet (000s)	68,290	71,361	73,489	74,165	73,495	75,739	74,316	74,335	74,625
percentage change	*4.1*	*4.5*	*3.0*	*0.9*	*–0.9*	*3.1*	*–1.9*	*0.0*	*0.4*
Vacancy rate (%)	6.0	9.6	12.1	14.2	13.5	9.6	7.6	5.6	4.9
Employment (000s)	930	944	987	1,026	1,026	1,049	1,075	1,126	1,153
percentage change	*3.5*	*1.6*	*4.5*	*3.9*	*0.0*	*2.3*	*2.5*	*4.8*	*2.4*
Bankruptcies**									
Consumer	7,677	8,477	9,210	10,321	10,691	10,983	10,349	10,597	12,208
Business	1,047	1,307	1,112	1,106	1,016	1,089	1,093	1,085	1,122

*Finance, insurance, & real estate, commercial services, and public administration.
**Beginning in 2006, the geographic boundaries changed from major urban centre to census metropolitan area.
Sources: Statistics Canada; Industry Canada; Colliers; The Conference Board of Canada.

Construction, Commercial Real Estate, and Income Overview (cont'd)

Taxable income by sub-metropolitan area (2006)

Sub-metro area	Total taxable income ($ 000s)	Total filers	Taxable income/filer ($ 000s)	Employment income (% of taxable income)
Toronto	82,088,443	1,888,240	43.47	64
Mississauga	19,639,634	502,820	39.06	75
Markham	11,424,204	266,670	42.84	70
Brampton	10,652,351	322,320	33.05	79
Oakville	8,172,706	121,950	67.02	71
Vaughan	5,800,849	129,980	44.63	76
Richmond Hill	5,787,889	133,380	43.39	73
Pickering	2,800,887	62,330	44.94	77
Ajax	2,753,665	65,900	41.79	81
Newmarket	2,614,490	56,100	46.60	76
Caledon	2,189,275	41,680	52.53	72
Milton	2,164,354	43,450	49.81	77
Halton Hills	2,073,651	41,490	49.98	75
Aurora	2,002,606	33,600	59.60	74
Orangeville	1,076,538	25,650	41.97	72
King	1,056,544	13,890	76.07	62
Georgina	1,043,522	28,910	36.10	74
Rest of Toronto CMA	3,956,312	84,400	46.88	69

Sources: Canada Revenue Agency; The Conference Board of Canada.

Sectoral Employment

	2006	2007	2008	2009f	2010f	2011f	2012f	2013f
Total employment (000s)	2,802	2,866	2,921	2,890	2,945	3,032	3,141	3,218
	1.4	*2.3*	*1.9*	*–1.1*	*1.9*	*3.0*	*3.6*	*2.4*
Goods sector	614	601	607	527	525	535	547	558
	–5.8	*–2.1*	*1.0*	*–13.2*	*–0.5*	*2.0*	*2.2*	*2.1*
Primary	11.9	12.2	12.2	11.4	11.2	11.9	12.2	12.6
	–1.7	*3.1*	*–0.3*	*–6.1*	*–2.5*	*6.2*	*2.8*	*3.6*
Manufacturing	423.1	404.4	391.8	353.9	349.6	350.7	352.1	351.0
	–8.3	*–4.4*	*–3.1*	*–9.7*	*–1.2*	*0.3*	*0.4*	*–0.3*
Construction	166.8	168.8	183.4	145.6	147.7	155.5	164.8	176.5
	2.4	*1.2*	*8.6*	*–20.6*	*1.5*	*5.3*	*6.0*	*7.1*
Utilities	12.2	15.5	19.6	16.3	16.1	16.8	17.5	17.9
	–22.0	*27.4*	*26.5*	*–17.1*	*–1.0*	*4.3*	*4.0*	*2.5*
Services sector	2,188	2,265	2,314	2,363	2,420	2,497	2,595	2,660
	3.6	*3.5*	*2.2*	*2.1*	*2.4*	*3.2*	*3.9*	*2.5*
Transport & communications	244.5	233.8	262.7	266.0	268.8	274.1	282.8	288.5
	9.0	*–4.4*	*12.4*	*1.2*	*1.1*	*2.0*	*3.2*	*2.0*
Wholesale & retail trade	459.3	464.4	453.9	449.5	455.0	466.3	483.8	495.1
	3.3	*1.1*	*–2.2*	*–1.0*	*1.2*	*2.5*	*3.8*	*2.3*
Finance, insurance, & real estate	286.8	286.0	284.2	304.7	304.8	315.1	327.6	335.9
	5.4	*–0.3*	*–0.6*	*7.2*	*0.0*	*3.4*	*4.0*	*2.5*
Commercial services	701.0	748.9	762.2	795.9	815.0	839.9	872.4	895.4
	2.1	*6.8*	*1.8*	*4.4*	*2.4*	*3.1*	*3.9*	*2.6*
Non-commercial services	409.3	440.0	443.9	445.8	472.5	493.0	513.6	526.7
	4.1	*7.5*	*0.9*	*0.4*	*6.0*	*4.3*	*4.2*	*2.5*
Public administration	87.3	91.6	107.0	101.2	104.1	108.6	114.5	118.3
	–3.9	*5.0*	*16.8*	*–5.5*	*2.9*	*4.3*	*5.4*	*3.3*

Shaded area represents forecast data.
First line of employment data is in thousands and second line is percentage change.
Sources: Statistics Canada; The Conference Board of Canada.

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INTERROGATORY 5:

Reference(s): B1/T14/S1

a) Please provide THESL's achieved reliability performance for the period 2006 to 2008 for SAIDI, SAIFI and CAIDI, with and without Loss of Supply interruptions but including Major Event Days (MEDs), by filling out the following table.

	All Service Interruptions			Service Interruptions excluding Loss of Supply (Cause Code 2)		
	SAIDI	SAIFI	CAIDI	SAIDI	SAIFI	CAIDI
2006						
2007						
2008						

b) Please provide any information THESL has about the incident of MEDs in other North American utilities comparable to THESL for the period from mid 2003 to mid 2009.

RESPONSE:

a) Please see the following tables for THESL's achieved reliability performance for the period 2006 to 2008 for SAIDI, SAIFI and CAIDI, with and without Loss of Supply interruptions but including Major Event Days ("MEDs"):

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Table 1: Reliability Performance with Loss of Supply but including Major Event Days (MEDs)

Service Reliability Indicators Performance Measures (with Loss of Supply but including Major Event Days)	2006 Actual	2007 Actual	2008 Actual
SAIDI (number of hours of interruption per customer)	1.57	1.95	1.24
SAIFI (number of customer per interruption)	2.17	2.28	1.76
CAIDI (number of hours per interruption)	0.72	0.86	0.70

Table 2: Reliability Performance without Loss of Supply but including Major Event Days (MEDs)

Service Reliability Indicators Performance Measures (without Loss of Supply but including Major Event Days)	2006 Actual	2007 Actual	2008 Actual
SAIDI (number of hours of interruption per customer)	1.38	1.85	1.21
SAIFI (number of customer per interruption)	1.91	2.04	1.66
CAIDI (number of hours per interruption)	0.72	0.91	0.73

b) THESL has information about comparable Major Event Days experienced by other North American utilities from the CEA (Canadian Electricity Association) from

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2003 to 2008. 2009 information has not been compiled by CEA. However, due to the confidentiality agreement between participating utilities in CEA, we are not in the position to share other participants' data.

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INTERROGATORY 6:

Reference(s): **J1/T1/S2, p.9**
J1/ T2/ S10, p. 2
M1/T2/S2

In the first reference, it is stated that: "THESL proposes a $/kWh rate rider for each class. Since the RSVA Global Adjustment balances have been based on energy usage for all classes, this is the appropriate way to dispose of the balances.

The treatment proposed by THESL for billing the regulatory asset recoveries is in line with the Board's EDDVAR report." The second reference provides THESL's development of the global adjustment rate rider.

a) Please state why THESL believes that its proposed treatment for billing the regulatory asset recoveries is in line with the Board's EDDVAR report.
b) The second reference includes a line item "Distribution kWh for Global Adjustment Recovery." Please state how this was calculated.
c) The second reference includes a line item "2009 Approved Distribution Revenue (2009 Filed DRO)". Please state how these numbers are used in the calculations.
d) The second reference states that the allocator used is "2008 Non-RPP Allocation in each Rate Class." Please state why this allocator was used and how it was calculated.
e) Please provide an explanation of the "Allocator Percentages" shown for "2008 of Non-RPP KWH as a % of the total Rate Class kWh."
f) Please state why a three-year mitigation plan is incorporated.
g) Please explain how THESL is identifying non-RPP customers.
h) Please state why THESL did not include an explanation of the applicability of the "Global Adjustment Rate Rider" on its proposed "Tariff of Rates and Charges"

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effective May 1, 2010.

RESPONSE:

a) The Board EDDVAR Report was released on July 31, close to the filing of THESL's evidence. THESL believes its evidence on the treatment of the deferral and variance accounts in the main follows the details of the EDDVAR Report. THESL's proposed class allocation of the regulatory asset recoveries is mostly in accordance with "Table 1 – Summary of the Default Allocation Factors" of the Board's EDDVAR report. THESL has proposed a Rate Rider which is volumetric based which is in accordance with the EDDVAR report.

	Accounts	*OEB's Default Allocation factors*	*THESL Allocation factors*
1580	RSVA - Wholesale Market Service Charge	kWh	kWh
1582	RSVA - One-time Wholesale Market Service	kWh	kWh
1584	RSVA - Retail Transmission Network Charge	kWh	kWh
1586	RSVA - Retail Transmission Connection Charge	kWh	kWh
1588	RSVA - Power (excluding Global Adjustment)	kWh	kWh
1588	RSVA - Power (Global Adjustment)	kWh for non-RPP Customers	kWh for non-RPP Customers
1508	Other Regulatory Assets - Sub-Account - Intangible Assets	Dist Rev	Dist Rev
1550	LV Variance Account	kWh	kWh
1592	2006 PILs & Taxes Variance	Case by case	Dist Rev

b) On a monthly basis, reports are generated from THESL's billing system that summarize both the RPP and Non-RPP kWh by rate class. Based on the historical

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proportions of Non-RPP kWh, the 2010 estimate of Non-RPP kWh is estimated to calculate the Rate Riders.

c) "2009 Approved Distribution Revenue (2009 Filed DRO)" were used to allocate the 1508 and 1592 balances.

d) The ratios "2008 Non-RPP Allocation in each rate class" is the rate class percentage share of the total Non-RPP kWh from all rate classes. These values were used to allocated the 1588 Global Adjustment balances to the rate classes.

e) The ratios "2008 of Non-RPP kWh as a % of the total Rate Class kWh" is the rate class Non-RPP kWh as a percentage of the rate class total kWh. Please see the explanations for b) above.

f) The total of the Regulatory Assets proposed for disposition is a significant amount. In THESL's opinion, spreading the disposition of these amounts over three years provides for a smoother transition of rates to customers.

g) Non-RPP and RPP customers are identified with a unique rate code in THESL's billing system.

h) THESL will include an explanation of the applicability of the "Global Adjustment Rate Rider" on its updated "Tariff of Rates and Charges".

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INTERROGATORY 7:

Reference(s): K1/ T1/ S1, p. 6

THESL stated that economic conditions are captured in its model by the customer, population, and time trend variables:

a) Please provide further explanation as to how the linear trend variable is developed.
b) The time trend variable has a negative co-efficient. This suggests that as the value of the variable increases, the resulting volume would decrease. Given this relation, how is it appropriate that as economic conditions improve, volume declines?
c) Please provide an alternate scenario excluding the linear trend variable.
d) Please provide an alternate scenario including other economic indicators such as Toronto area real GDP monthly index numbers.
e) THESL states that "one of the significant drivers of these decreases is believed to be the impact of conservation…" Please provide an explanation as to why CDM is captured by an economic variable.

RESPONSE:

a) The trend variables are traditionally used when there is a need to reflect continuous historic growth/decline in a dependant variable. The necessity and reasonability of adding trend variables to THESL class loads regression models were tested for each customer class independently.

   As the first step, class historic loads were analysed on an annual and monthly basis. Based on the analysis, determinations were made on the customer class loads that had been showing a declining trend (residential, GS<50 kW, GS 1-5 MW and Large

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Users), and which of them appeared to be stable (GS 50-1000 kWh, Street Lighting, USL).

Then, based on the load behaviour, a number of linear time trend variables were generated for each customer class. Trend variables were distinguished and defined by the month when a decline started to take place.

Generated trend variables were tested for statistical significance along with other explanatory variables in the regression models for each customer class independently. Based on the results of statistical estimation (trend variables significance in the models and adjusted R^2) "the best-fitted" trend variables were chosen for those customer classes which demonstrated a decline in a recent history: July 2002 for Residential and GS<50 kW, Jan 2007 for GS 1-5 kW and Large Users. For monthly values of the trend variables please refer to Table 1, Exhibit K1, Tab 2, Schedule 1 (Columns 12 and 13).

b) The time trend variable is not meant to directly reflect the impact of improving / worsening economic conditions on loads since it is not a "pure" economic indicator (as opposed to Toronto GDP). The usage of such variables implies that the general pattern of dependent variable will stay the same for the forecasting horizon.

The fact that the trend variable is significant and has a negative coefficient is a statistical proof of the declining tendency in class loads over recent history, which is expected to be in place at least for the forecast horizon based on the slow recovery of economy and conservation activities held in the City of Toronto.

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If as time goes by economic conditions improve, and THESL loads for any given customer class start picking up (or are expected to pick up within the forecasting horizon), the trend variable will be reconsidered (modified, replaced or complemented with other variables) to reflect structural changes in the load behaviour.

c) Table 7.1 below represents class model estimations with trend variables excluded from the list of explanatory variables (for those customer classes where trend variables were originally used). All other variables were left the same as in the filed forecast. The table contains:

1) Coefficients' estimations and probabilities to reflect their significance/insignificance (in brackets below the estimation).
2) R^2 Adjusted criterion values for each customer class.

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Table 7.1: Alternative scenario "No trend variable" – regression models by class

Variables	Residential	GS<50 kW	GS 1-5 MW	Large Users
CDD18 per day	887,105 (0.0000)	292,874 (0.0000)	321,789 (0.0000)	156,242 (0.0025)
HDD10 per day	272,042 (0.0000)	82,820 (0.0000)	161,273 (0.0000)	92,417 (0.0000)
Dew	n/a	8,186 (0.2349)	92,058 (0.0000)	45,834 (0.0068)
Business Days %	n/a	10,269 (0.0130)	65,607 (0.0000)	26,396 (0.0059)
Customer numbers	n/a	196 (0.0001)	7,581 (0.0016)	n/a
Population	- 4,878 (0.0000)	- 3,840 (0.0000)	n/a	n/a
Trend Jul 2002	Excluded	Excluded	n/a	n/a
Trend Jan 2007	n/a	n/a	Excluded	Excluded
Blackout Dummy	- 1,208,205 (0.0000)	- 363,379 (0.0000)	- 980,245 (0.0000)	- 277,493 (0.0047)
Intercept	23,399,473 (0.0000)	747,855 (0.8424)	4,701,571 (0.0006)	4,694,738 (0.0000)
R^2 Adjusted	93.64%	94.4%	88.2%	53.9%

Compared to original regression models provided in Exhibit K1, Tab 2, Schedule 2, Page 1-3 of the filed evidence, all models of the alternative scenario performed worse: R^2-Adjusted lowered, population with negative coefficients "trying" to reflect declining load pattern.

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Although THESL does not see any rationale to produce a load forecast based on the models which are significantly worse than the ones in the filed evidence, the load forecast outcome is still provided as requested.

Table 7.2 below represents load forecast values (total system and each customer class separately) produced by the regression models with the linear trend variable excluded. The table also contains values of the originally filed forecast.

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Table 7.2: Alternative scenario "No trend variable" vs filed forecast: loads by class

Customer Class	2009		2010	
	No trend variable scenario	Filed forecast	No trend variable scenario	Filed forecast
Residential, kWh	5,392,530,254	5,325,249,346	5,379,273,208	5,272,075,340
GS<50 kW, kWh	2,385,464,984	2,363,253,024	2,349,955,607	2,313,304,620
GS 50-1000 kW, kWh	10,467,082,781		10,515,391,404	
GS 1-5 MW, kWh	5,258,126,225	5,129,549,319	5,326,131,067	5,064,154,889
Large Users, kWh	2,601,557,004	2,481,159,250	2,662,443,492	2,422,593,201
Street Lighting, kWh	112,747,163		113,408,585	
USL, kWh	54,418,934		54,384,061	
Total Purchased Energy, kWh	**26,271,927,345**	**25,933,459,818**	**26,400,987,424**	**25,755,312,099**
Note 1. Loads are before losses				

Total Purchased Energy forecast for the test 2010 year under this scenario is higher than 2008 and 2007 historic THESL load (refer to Table 1 Exhibit K1, Tab 1, Schedule 1, Page 1) which THESL does not believe is appropriate given the ongoing declining trend in THESL's total load experienced in the recent years.

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d) As no specific directions were provided on which economic variables to use (except for Toronto GDP), and whether to keep trend variables or not, two alternative scenarios were run.

In the first scenario a GDP variable was added to the original set of explanatory variables (for those customer classes where GDP variable is applicable).

A second scenario was built excluding trend variables and replacing them with Toronto GDP variable where applicable. For 50-1000 kW customer class specification for this scenario is the same as for the first scenario as no trend variable was originally used in the filed forecast for this customer class.

Alternative scenario I: Toronto GDP added as a variable to the original set of explanatory variables

Table 7.3 below represents class models estimations with GDP variable added to the original set of variables. The table contains:

1) Coefficients' estimations and probabilities to reflect their significance/insignificance (in brackets below the estimation).
2) R^2-Adjusted and Schwartz criterion values for each customer class.

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Table 7.3: Alternative scenario “Toronto GDP added” regression models by class

Variables	Residential	GS<50 kW	GS 50-1000 kW	GS 1-5 MW	Large Users
CDD18 per day	851,720 (0.0000)	272,332 (0.0000)	931,759 (0.000)	347,887 (0.0000)	186,198 (0.0000)
HDD10 per day	279,875 (0.0000)	87,626 (0.0000)	410,185 (0.000)	144,459 (0.0000)	71,117 (0.0004)
Dew	n/a	9,281 (0.0790)	87,059 0.000	75,745 0.0000	26,673 0.0872
Business Days %	n/a	8,517 (0.0181)	39,965 (0.000)	63,530 (0.0000)	23,022 (0.0189)
Customer numbers	n/a	89 (0.0451)	695 (0.008)	10,841 (0.0290)	n/a
Population	8,991 (0.0076)	1,792 (0.0406)	n/a	n/a	n/a
Blackout Dummy	- 1,225,388 (0.0000)	- 322,598 (0.0000)	- 1,654,553 (0.000)	- 947,740 (0.0000)	- 344,838 (0.0009)
Trend Jul 2002	- 23,260 (0.0034)	- 16,145 (0.0000)	n/a	n/a	n/a
Trend Jan 2007	n/a	n/a	n/a	- 22,032 (0.0001)	- 17,181 (0.0012)
Intercept	- 593,934 (0.9314)	- 4,361,959 (0.1603)	13,641,739 (0.000)	2,499,724 (0.0571)	5,271,700 (0.0001)
Toronto GDP	- 23 (0.0138)	4 (0.3696)	3 (0.782)	4 (0.5582)	- 1 (0.9047)
R^2 Adjusted	94.8%	96.1%	96.4%	91.71%	61.6%

Compared to original regression models provided in Exhibit K1, Tab 2, Schedule 2, Page 1-3 of the filed evidence, all models of the alternative scenario performed worse: R^2-Adjusted lower for all customer classes (GS<50 kW – stayed the

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same), and GDP coefficient is highly insignificant for all customer class (except for Residential) and negative for LU (which doesn't make economic sense). All the above support the decision not to include GDP indicator as a variable for any of the class models.

Although THESL does not see any rationale to produce a load forecast based on the models which are significantly worse than the ones in the filed evidence, the load forecast outcome is still provided as requested.

Table 7.4 below represents load forecast values (total system and each customer class separately) produced by the regression models with the GDP variable added to the original set of variables. The table also contains values of the originally filed forecast.

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Table 7.4: Alternative scenario "Toronto GDP added" vs filed forecast: loads by class

Customer Class	2009		2010	
	"Toronto GDP added" scenario	Filed forecast	"Toronto GDP added" scenario	Filed forecast
Residential, kWh	5,390,886,291	5,325,249,346	5,346,511,179	5,272,075,340
GS<50 kW, kWh	2,351,834,699	2,363,253,024	2,300,830,639	2,313,304,620
GS 50-1000 kW, kWh	10,459,238,310	10,467,082,781	10,509,352,147	10,515,391,404
GS 1-5 MW, kWh	5,121,176,358	5,129,549,319	5,057,311,087	5,064,154,889
Large Users, kWh	2,483,050,445	2,481,159,250	2,425,464,154	2,422,593,201
Street Lighting, kWh	112,747,163		113,408,585	
USL, kWh	54,418,934		54,384,061	
Total Purchased Energy, kWh	**25,973,352,200**	**25,933,459,818**	**25,807,261,851**	**25,755,312,099**

Total Purchased Energy forecast for the test 2010 year turned out to be 25,807,261,851 kWh which is not significantly higher than originally filed forecast. Given that the quality of the models got worse THESL sees no reason to replace its originally filed forecast with the proposed scenario.

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Alternative scenario II: Trend variables were replaced with Toronto GDP (where applicable); all other variables left the same.

Table 7.5 below represents class models estimations with trend variables replaced by GDP variable (Residential, GS<50 kW, GS 1-5 MW and Large Users). For GS 50-1000 kW customer class, GDP was added to the original set of variables as no trend was used for this customer class in the filed forecast. The table contains:

1. Coefficients' estimations and probabilities to reflect their significance/insignificance (in brackets below the estimation).
2. R^2-Adjusted and Schwartz criterion values for each customer class.

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Table 7.5: Alternative scenario "Trend variables replaced with Toronto GDP" regression models by class

Variables	Residential	GS<50 kW	GS 50-1000 kW	GS 1-5 MW	Large Users
CDD18 per day	877,278 (0.0000)	281,056 (0.0000)	931,759 (0.0000)	312,782 (0.0000)	165,490 (0.0002)
HDD10 per day	274,553 (0.0000)	88,301 (0.0000)	410,185 (0.0000)	167,192 (0.0000)	84,093 (0.0000)
Dew		12,566 (0.0645)	87,059 (0.000)	97,300 (0.0000)	39,435 (0.0111)
Business Days %		9,628 (0.0228)	39,965 (0.0000)	65,743 (0.0000)	24,330 (0.0209)
Customer numbers		216 (0.0000)	695 (0.0080)	19,778 (0.0004)	
Population	1,807 (0.3312)	- 2,130 (0.0103)	n/a		
Blackout Dummy	- 1,318,831 (0.0000)	- 392,579 (0.0000)	- 1,654,553 (0.0000)	- 1,025,246 (0.0000)	- 399,662 (0.0001)
Trend Jul 2002	Excluded	Excluded	n/a	n/a	n/a
Trend Jan 2007	n/a	n/a	n/a	Excluded	Excluded
Intercept	17,204,134 (0.0000)	- 2,306,148 (0.5200)	13,641,739 (0.0000)	1,924,370 (0.2324)	6,747,568 (0.0000)
Toronto GDP	- 39 (0.0005)	- 9 (0.0231)	3 (0.782)	- 16 (0.0206)	- 9 (0.0271)
R^2 Adjusted	**94.3%**	**94.6%**	**96.4%**	**88.7%**	**56.6%**

Compared to original regression models provided in Exhibit K1, Tab 2, Schedule

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2, Page 1-3 of the filed evidence, all models of the alternative scenario performed significantly worse: R^2-Adjusted was lower for all customer classes, and the GDP coefficient was either insignificant or has unreasonable negative coefficients. Additionally, the population variable has a negative coefficient for certain classes. This evidence supports the fact that GDP is not accurately reflecting loads.

Although THESL does not see any rationale to produce a load forecast based on the models which are significantly worse than the ones in the filed evidence, the load forecast outcome is still provided for the sake of consistency.

Table 7.6 below represents load forecast values (total system and each customer class separately) produced by the regression models with trend variables being replaced by GDP variable.

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Table 7.6: Alternative scenario "Trend variables replaced with Toronto GDP" vs filed forecast: loads by class

Customer Class	2009		2010	
	"Toronto GDP instead of Trend" scenario	Filed forecast	"Toronto GDP instead of Trend" scenario	Filed forecast
Residential, kWh	5,477,306,945	5,325,249,346	5,463,806,069	5,272,075,340
GS<50 kW, kWh	2,404,751,026	2,363,253,024	2,368,241,066	2,313,304,620
GS 50-1000 kW, kWh	10,459,238,310	10,467,082,781	10,509,352,147	10,515,391,404
GS 1-5 MW, kWh	5,262,268,685	5,129,549,319	5,296,142,533	5,064,154,889
Large Users, kWh	2,580,742,130	2,481,159,250	2,598,171,441	2,422,593,201
Street Lighting, kWh	112,747,163		113,408,585	
USL, kWh	54,418,934		54,384,061	
Total Purchased Energy, kWh	**26,351,473,192**	**25,933,459,818**	**26,403,505,903**	**25,755,312,099**

Total Purchased Energy forecast for the test 2010 year turned out to be higher than 2008 and 2007 historic THESL load (refer to Table 1 Exhibit K1, Tab 1, Schedule 1, Page 1). Overall the tested scenario proves to be unacceptable.

e) THESL did not state that CDM impact was captured by the economic variables in THESL regression models. Trend variables are not pure economic indicators (such as

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GDP), but constructed integer variables incorporating time trends into the models. They are aimed to capture and reflect an ongoing decline in loads evident for certain customer classes. Built as a linear time trend this variable indirectly incorporates various factors contributing to the ongoing load decrease. However, THESL assumes that among these factors, recent economic decline as well as ongoing and growing conservation activity are the most crucial to loads behaviour. Therefore, by having significant trend variables included in the set of explanatory variables, THESL ensures that the impact of those factors is being captured and transferred into the forecast.

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INTERROGATORY 8:

Reference(s): K1/ T2/ S1, p. 1-3

This exhibit provides an overview of the model input data. Purchased energy per day, kWh is allocated by customer class.

Please describe how purchased energy was allocated to each customer class.

RESPONSE:

Purchased energy is allocated by customer class based on the historic billed kWh percentage. The process of purchased energy allocation consists of the following steps:

1) Historic billed kWh are collected for each customer class.
2) Billed kWh for each customer class are prorated to the months of actual consumption.
3) Percentage of class prorated kWh in total prorated kWh is calculated for each customer class
4) Derived percentages are applied to historic total purchased energy to get purchased energy by customer class.

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INTERROGATORY 9:

Reference(s): K1/ T1/ S1, p. 6

THESL states that the standard definition of HDD, which uses 18 degrees Celsius as the point at which loads start to be impacted by temperature, was not as effective as a measure which uses 10 degrees Celsius as the "balance point".

a) The acceptable standard for HDD for both electricity distributors as well as gas distributors is a balancing point of 18 degrees Celsius. Please provide further evidence supporting a change of this standard to 10 degrees Celsius.
b) Does a reduction of the balancing point from 18 degrees Celsius to 10 degrees Celsius effectively lower THESL's load forecast?
c) Please re-run the load forecast using the standard HDD 18 degrees Celsius in the regression model and subsequent regression equation.

RESPONSE:

a) THESL accepts that HDD based on 18 degrees Celsius has been the "norm" for quite some time. In developing its load forecast, THESL is interested in developing the best statistical relationships between observed variables and loads. Depending on the service area, the load-temperature relationship may have changed over time due to the improving technology, change in insulation standards, housing stock and energy end-users behaviour.

   Prior to developing its load forecasting models THESL did research on the degree day calculation issue, including communicating with meteorological services as well as discussing the issue at load forecasting conferences. Based on the information collected, THESL believed that it was reasonable to question whether HDD based on

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the 18 degrees Celsius balance point is an accurate reflection of weather-related load patterns.

The THESL load-temperature relationship presented on the graph in Exhibit K1, Tab 1, Schedule 1, page 7 of the filed evidence clearly illustrates that, on average the heating portion of Toronto's load starts to grow when temperatures fall below 10 degrees, not 18 Degrees. Also, as the graphs below illustrate, HDD10 is more suitable for use in linear regression as the HDD10-load relationship has a linear shape. On the contrary, the HDD18-load relationship, at lower values, forms a parabolic-type curve, which might worsen its performance in linear regression models.

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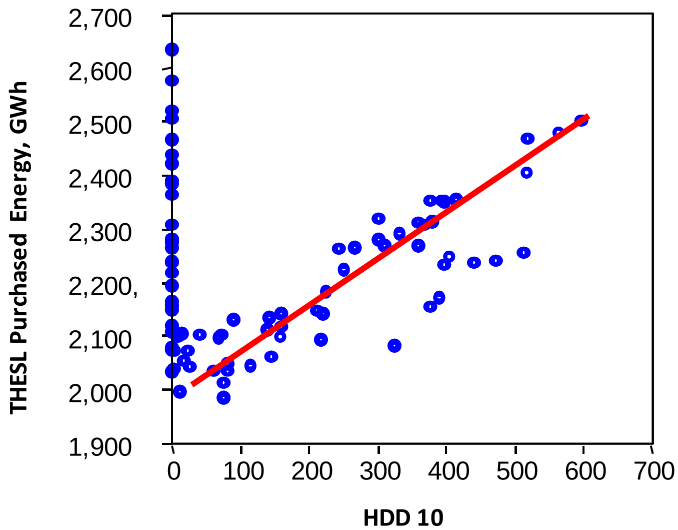

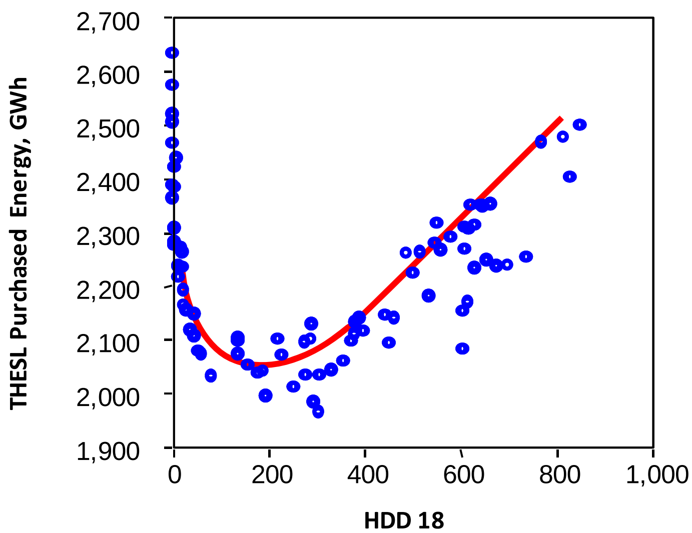

Based on the preliminary analysis of its loads, THESL chose a set of HDD and CDD balance point temperatures, and statistically tested their performance in customer class regressions (as stated on Page 7 of Exhibit K1, Tab 1, Schedule 1 of the filed evidence).

The results enabled THESL to confirm that CDD18 still properly reflected the

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cooling portion of the load-temperature relationship, whereas the results suggest that the HDD balance temperature should be shifted from 18 to 10 Degree Celsius for better modeling of class loads.

b) No, the usage of a 10 degree Celsius balancing point instead of an 18 degree Celsius for HDD calculations does not reduce THESL's load forecast. On the contrary, it makes Total Purchased Energy amount projected for 2009 and 2010 years higher when compared to the model variation using an 18 degree HDD balancing point. For more detailed comparison please refer to question 9-c, Table 9.2, below.

c) Table 9.1 below represents class models estimations with HDD 10 replaced by standard HDD18 degree Celsius where applicable. The table contains:
   1) Coefficient estimations and probabilities to reflect their significance/insignificance (in brackets below each estimation).
   2) R^2-Adjusted values for each customer class.

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Table 9.1: Alternative scenario "HDD18 instead of HDD10" regression models by class

Variables	Residential	GS<50 kW	GS 50-1000 kW	GS 1-5 MW	Large Users
CDD18	1,122,939 (0.0000)	344,372 (0.0000)	1,249,569 (0.000)	472,456 (0.0000)	237,185 (0.0000)
HDD18 (instead of HDD10)	219,108 (0.0000)	75,487 (0.0000)	358,834 (0.000)	109,923 (0.0000)	67,827 (0.0012)
Dew	n/a	18,917 (0.0587)	133,887 (0.030)	74,987 (0.0049)	40,526 (0.0558)
Business Days %	n/a	8,470 (0.1299)	38,597 (0.068)	61,340 (0.0000)	23,362 (0.0253)
Customer numbers	n/a	129 (0.0383)	689 (0.000)	12,981 (0.0000)	n/a
Population	3,615 (0.3381)	432 (0.7596)	n/a	n/a	n/a
Trend Jul 2002	- 21,656 (0.0146)	- 11,157 (0.0024)	n/a	n/a	n/a
Trend Jan 2007	n/a	n/a	n/a	- 23,013 (0.0000)	- 18,176 (0.0000)
Blackout Dummy	- 1,215,076 (0.0000)	- 363,604 (0.0000)	- 1,732,190 (0.000)	- 989,178 (0.0000)	- 349,088 (0.0001)
Intercept	4,932,416 (0.5235)	- 3,788,999 (0.4029)	12,286,990 (0.000)	1,978,811 (0.1999)	4,708,617 (0.0000)
R^2 Adj	93.9%	92.7%	89.5%	85.8%	60.1%

Compared to the filed regression models provided in Exhibit K1, Tab 2, Schedule 2, Page 1-3 of the filed evidence, all models of the alternative HDD18 scenario

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performed worse: R^2 Adjusted declined for all customer classes.

Table 9.2 below presents load forecast values (total system and each customer class separately) produced by the regression models with the HDD10 variable replaced by HDD18 where applicable.

Table 9.2: Alternative scenario "HDD18 instead of HDD10" vs filed forecast: loads by class

Customer Class	2009		2010	
	"HDD18 instead of HDD10" scenario	Original model outcome (HDD 10)	"HDD18 instead of HDD10" scenario	Original model outcome (HDD 10)
Residential, kWh	5,323,373,420	5,325,249,346	5,268,260,988	5,272,075,340
GS<50 kW, kWh	2,364,368,276	2,363,253,024	2,313,013,860	2,313,304,620
GS 50-1000 kW, kWh	10,452,477,734	10,467,082,781	10,485,559,600	10,515,391,404
GS 1-5 MW, kWh	5,112,657,832	5,129,549,319	5,029,624,579	5,064,154,889
Large Users, kWh	2,476,636,729	2,481,159,250	2,412,166,865	2,422,593,201
Street Lighting[1], kWh	112,747,163		113,408,585	
USL[1], kWh	54,418,934		54,384,061	
Total Purchased Energy, kWh	**25,896,680,088**	**25,933,459,818**	**25,676,418,538**	**25,755,312,099**

[1] HDD variable modification is not applicable

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INTERROGATORY 10:

Reference(s): K1/ T2/ S1, p. 1

Table 1 Note 1 indicates that THESL has applied a loss factor to convert purchased energy to billed energy by class. Please confirm that this is what THESL has done and provide details of this conversion including the loss factor used.

RESPONSE:

There is no such note in Table 1, Exhibit K1, Tab 2, Schedule 1. However, Note 1 underneath Table 1 Exhibit K1, Tab 3, Schedule 1 states "Loads are after losses". That implies that losses were applied to the class loads to convert purchased energy by class to sales by class. To perform these calculations the OEB-approved loss factors were used for each customer class. Table 10-1 below represents Loss Factors by customer class used for the calculation:

Table 10.1: Customer class loss factors applied to convert purchased energy to sales by class

Residential	GS<50 kW	GS 50-1000 kW	GS 1-5 MW	Large Users	Street Lighting	USL
1.0376	1.0376	1.0376	1.0376	1.0187	1.0376	1.0376

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INTERROGATORY 11:

Reference(s): **K1/ T3/ S2, p. 1**

THESL has indicated that is has normalized load by class using Test Year HDD and CDD. However, it is unclear to staff if HDD is based on a balancing point of 10 degrees Celsius or 18 degrees Celsius.

a) Please describe how THESL has weather-normalized the test year load.

b) Please confirm that the term "normalized" means "weather-normalized". Has THESL investigated any government training funds for applicability to their situation? If so, what were the outcomes? If not why not?

RESPONSE:

a) Test Year Loads are already weather normalized, as they incorporate the forecasted HDD and CDD. The normalization is applied to the actual and forecast years to put them on the same "weather basis" as the test year. Weather-normalization was performed using HDD based on the balancing point of 10 degrees Celsius. Weather normalization was performed for each customer class separately using historic monthly values of CDD and HDD10, CDD and HDD10 "normals" and corresponding regression model CDD and HDD10 coefficients. For example, to weather normalize monthly residential load the following CDD and HDD10 coefficients were used:
HDD10 per day: 280,208.
CDD per day: 849,055.

In accordance to the regression models specification, weather normalization was performed on a "load per day" basis. Resulting normalized load values were multiplied by the number of days in a given month. For example, to get weather

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normalized values for Residential July 2002 load the following calculation was performed:

(19,069,484 + (0 – 0) x 280,208 + ((4.3 – 6.2) x 849,055)) x 31
= 541,518,230 kWh (541,144,664 kWh due to rounding)

(For historic residential purchased energy per day, HDD10 and CDD data for July 2002 please see Table 1, ExhibitK1, Tab 2, Schedule 1, Line 4).

c) Yes, the term "normalization" means "weather-normalization" or "weather-correction", in other words, the conversion of an actual historic load which was influenced by the weather fluctuations to an equivalent load that is based on "typical" weather.

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INTERROGATORY 12:

Reference(s): K1/ T1/ S1, p. 10

THESL states that the forecast of customers for the residential sector in 2009 through 2010 includes an estimate for new individually-metered condominium suites, as well as the conversion of some condominiums from bulk-metered to individual suite-metering.

a) What is the percentage of new individually-metered suite meters and what is the percentage of converted individually suite meter from bulk meters?

b) Please provide an estimate of how many bulk meters are added each year.

c) Please provide an estimate of how many individually-metered suite meters result from a bulk meter.

d) Please provide a customer count forecast excluding the individual suite meters.

RESPONSE:

a)

Percentage of individually metered suites converted from bulk-metered condo (retrofits) in the total number of expected individually-metered suites	80%
Percentage of new individually-metered suites (new construction) in the total number of expected individually-metered suites	20%

This percentage was assumed at the time when the forecast was built based on the economy conditions and construction market expectations.

b) The number of new bulk or check meters installed at condominiums varies according to developer requests, but recently has been approximately 22 per year.

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c) The number of individually-metered suites resulting from a bulk meter conversion may vary anywhere from 20 to 300 suites depending on the size of the condominium, but would typically be about 175 suites.

d)

Year	Individually-Metered Suites (cumulative)	Residential Customers Forecast (year-end)	Residential Customers Forecast excluding individually-metered suites
2009	4,964	611,640	606,676
2010	8,564	618,042	609,478

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INTERROGATORY 13:

Reference(s): I1/ T1/ S1, pp. 3-5

THESL has forecast a decline in Other Income from $10.3 million in the 2008 historical year to zero in the 2010 test year. On page 3 THESL states that "THESL earns revenue by providing services to customers and third parties, gains on the sale of scrap metal, and earns interest income from short-term investments of its idle cash balances". Please break down these components of Other Income to demonstrate how the three factors referenced above have contributed to Other Income. Please provide this breakdown for the 2004 to 2008 Historical years, the 2009 Bridge and 2010 Test years. Please include:

a) the amount of any gains on the sales of scrap metal as well its book value at the time of sale.
b) the level of available cash for short-term investment
c) revenue earned by providing services to customers and third parties including revenue and expenses from Merchandise and Jobbing for the past five historic years.

RESPONSE:

The table below extends the data shown in Exhibit I1, Tab 1, Schedule 3, lines 32-36 for the requested years.

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Other Income and Deductions ($000s)							
	2004 Actual	2005 Actual	2006 Actual	2007 Actual	2008 Actual	2009 Bridge	2010 Test Year
Merchandising and Jobbing Revenue	8,917	12,064	11,963	20,594	14,337	9,433	8,596
Merchandising and Jobbing Costs	-8,650	-9,501	-9,270	-9,581	-10,498	-8,020	-8,596
Gain/Loss on Disposals	84	2,964	299	1,698	130	0	0
Foreign Exchange Gain/Loss	-27	-19	376	-703	360	0	0
Investment Interest Income	10,324	10,485	8,709	8,159	6,020	1,016	0
Total	10,649	15,993	12,078	20,167	10,349	2,428	0

a) Gains on sale of scrap metal are included in the Merchandising and Jobbing amounts. The net gains for the periods requested are shown in the following table. Scrap metals are salvaged from equipment and facilities that have served their useful life. There is no separate record of the book value of these scrap metals.

Gains on Sale of Scrap Metals (revenues minus expenses) ($000s)							
	2004 Actual	2005 Actual	2006 Actual	2007 Actual	2008 Actual	2009 Bridge	2010 Test Year
	1,499	1,288	1,975	3,229	2,720	1,204	0

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b) The average level of cash available for investing is shown in the following table.

Average cash available for Investing ($millions)							
	2004 Actual	2005 Actual	2006 Actual	2007 Actual	2008 Actual	2009 Bridge	2010 Test Year
	Not available	Not available	208.7	224.7	192.8	148.7	75.4

c) See table in answer to (a) above.

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INTERROGATORY 14:

Reference(s): **D1/T3/S1**
F1/T1/S1
F2/T1/S1
J1/T2/S1

In each of these Exhibits, different presentations of OM&A numbers are provided.

Exhibit D1 provides distribution expenses based on the Board's reporting categories.

Exhibit F1 provides operations and maintenance distribution expenses, while Exhibit F2 provides administration and general expenses. When these numbers are totaled, they are different from the total in Exhibit D1.

Exhibit J1 provides distribution expenses before PILs. These numbers are different from both those of Exhibits F1 and F2 and from Exhibit D1.

a) Please provide a schedule reconciling the differences between these numbers for all years contained in the application.
b) Please provide a breakdown of the drivers of the increases in THESL's OM&A costs in the format of Appendix 2-I of Chapter 2 of the Board's "Filing Requirements for Transmission and Distribution Applications" for the years 2008, 2009 Bridge and 2010 Test year.

RESPONSE:

a) Please see Tables 1 and 2 below.

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Table 1: Distribution Expense ($ millions)

	2008 Board-Approved	2008 Historical	2009 Board-Approved	2009 Bridge	2010 Test
Exhibit D1/T3/S1/Table 1	**338.1**	**331.6**	**350.0**	**352.6**	**387.9**
Less: Provincial Capital Taxes	(5.9)	(8.0)	(5.0)	(5.5)	(2.0)
Less: CDM Recoveries Gross vs. Net	(0.3)				
Rounding		(0.1)		0.2	(0.1)
Exhibit J1/T2/S1/Table 1	**331.9**	**323.5**	**345.0**	**347.3**	**385.8**

Table 2: Distribution Expense ($ millions)

	2008 Historical	2009 Bridge	2010 Test
Exhibit F1/T1/S1/Table 1	155.9	169.3	187.6
Less: Recoveries (Facilities / Fleet / Procurement)	(42.4)	(44.3)	(44.1)
Add: Exhibit F2/T1/S1/Table 1	68.8	70.2	78.0
Add: Amortization Expense	149.0	158.4	167.0
Less: Special Events & Donations		(1.0)	(0.6)
Add: Rounding	0.3		
Exhibit D1/T3/S1/Table 1	331.6	352.6	387.9

b) Appendix 2-I of Chapter 2 of the Board's "Filing Requirements for Transmission and Distribution Applications" references a Regulatory Cost Schedule. Refer to Board Staff 27 b for aforementioned schedule.

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INTERROGATORY 15:

Reference(s): F1/T1/S2/p4

It is stated that: "The total preventative maintenance program cost increased by $3.4 million from 2009 to 2010 to capture costs needed for street lighting asset verification in preparation for inclusion into THESL and an increase in the units and costs for scheduled preventative maintenance work as described in Exhibit F1, Tab 1, Schedule 3."

a) Please state why street lighting asset verification costs are included in the category of total preventative maintenance.

b) Please state whether the reference to "street lighting asset verification in preparation for inclusion into THESL" relates to the application presently before the Board relating to the reintegration of street lighting services in THESL. If yes, please state whether these costs would need to have been incurred in the absence of this application and to what extent, if any, the verification process relates to non-THESL assets. If no, please state what this reference means.

RESPONSE:

a) The asset verification referred to addresses verification of <u>THESL distribution equipment</u> necessary to connect street lighting equipment and supply points and does not include verification of the street lighting equipment itself.

b) The reference to "street lighting asset verification in preparation for inclusion into THESL" is related to the application presently before the Board relating to the reintegration of the street lighting services into THESL. In the absence of that application, THESL would still need to incur these costs to verify the conditions of

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the THESL distribution equipment used to connect street lighting equipment and supply points.

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INTERROGATORY 16:

Reference(s): F1/T1/S3/p4

It is stated that: "As is detailed in Exhibit C2, Tab 3 Schedule 3, THESL engages a number of qualified external entities to perform preventative maintenance tasks for several programs. External contractors are engaged to provide these services due to the seasonal nature of the work and the specialized expertise and equipment required. This practice of using external contracts is considered utility best practice in meeting seasonal maintenance requirements."

a) Please identify the basis for the statement that the use of external contracts "is considered utility best practice in meeting seasonal maintenance requirements" and whether or not THESL is aware of any utilities that meet these requirements internally.

b) Please state whether or not THESL's use of external contractors is based on a cost-benefit analysis. If so, please state the amount of annual savings, if not please identify the basis for outsourcing.

RESPONSE:

a) Based on past experience THESL considers the use of external experts for seasonal work a best practice to achieve cost efficiencies within time constraints for the following reasons:

Companies contracted by THESL for seasonal maintenance requirements are specifically trained and certified in their field of expertise. They own and operate equipment that meets or exceeds THESL specifications and have experience performing maintenance for many different utilities. The resources of these

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contractors are released at the end of the maintenance cycle when they are no longer required. This approach is more efficient than retaining full-time staff to perform these functions.

THESL is not aware of any similarly-sized utilities that perform this maintenance work internally.

b) THESL has not performed a cost-benefit analysis comparing THESL resources with third-party vendors specifically for seasonal contract work.

External contractors are used to perform seasonal work because they have specialized skills and can be deployed on a large-scale seasonally. This provides THESL with the advantage of rapid mobilisation to ensure timely and effective completion of each maintenance programme. Outsourcing also allows THESL to disengage surplus resources in a cost-effective manner, thus saving THESL from retaining equipment and staff that are limited to seasonal use. The cost of developing and maintaining staff with specific competencies for seasonal use is not cost-effective. For example, THESL has found efficiencies in maintaining a small team of specialised foresters to respond to immediate needs, with large scale mobilisation outsourced.

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INTERROGATORY 17:

Reference(s): F1/T1/S4/p4

It is stated that: "THESL uses a ten-year inspection cycle for testing and treatment of its inventory of 159,000 wood poles." Please state whether the ten-year inspection cycle is an industry standard and if not, how it was determined.

RESPONSE:

The Canadian Electrical Association does not have any recommendations for a testing cycle for wood poles. THESL follows a ten-year inspection cycle because that is the manufacturer specified lifespan of our wood pole remedial treatment chemicals. The chemicals used by THESL's pole testing contractor meet or exceed the ten-year lifespan.

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INTERROGATORY 18:

Reference(s): F1/T1/S4/pp5-7

It is stated on page 5 that: "THESL has elected to employ mobile contact voltage scanning technology. Power Survey Company, which owns the rights to the technology, has been selected to perform scans of the distribution system in Toronto…"

Subsequently on pages 6 and 7 it is stated when discussing the 2010 predictive maintenance costs that: "In the test year however, there is a significant increase in spending due to the introduction of the Contact Voltage Scan program of $4 million as well as $0.2 million in underground high voltage cable partial discharge testing and minor variations in other predictive maintenance programs."

a) Please confirm that the $4 million in costs referenced above relates to the services performed by Power Survey Company, or, if not, what portion of the costs relates to this contract and what the remainder is for.
b) Please provide a detailed breakdown of these costs.
c) Please describe the process by which Power Survey Company was selected, including whether or not there was a competitive bidding process and, if not, why not.
d) Please state whether or not the decision to hire Power Survey Company was based on any cost/benefit analyses. If so, please provide the results, if not, please explain why not.

RESPONSE:

a) Yes, the $4 million cost referenced above is related to services performed by the Power Survey Company for the Contact Voltage Scan program.

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b) This is a lump-sum contract amount to perform contact voltage scanning in the City of Toronto in 2010.

c) Power Survey Company has been conducting contact voltage scans successfully for major cities in the United States, including New York City. They have proprietary technology that has been proven in the field to be effective and efficient in identifying locations where contact voltage is present. During the 2009 Level III emergency event, they were engaged to conduct a survey of the streets in Toronto. 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 Power Survey Company to perform regularly scheduled contact voltage scans in 2010, since they hold the patent to this scanning technology. There is no comparable technology available in the marketplace. The Power Survey Company's cost was evaluated and found to be reasonable.

d) The reasons for selecting Power Survey Company are provided above in response to part c) of this question.

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INTERROGATORY 19:

Reference(s): F1/T1/S5/p3

Table 1: Corrective Maintenance Costs shows an increase in External Contracts in the 2010 Test year to $0.9 million from the $0.5 million levels in the 2009 Bridge and 2008 Historical years. Please state the reason for this increase.

RESPONSE:

The increase in external corrective maintenance spending is a restoration of funding to levels approaching that of 2006 and 2007. This amount better reflects ongoing requirements.

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INTERROGATORY 20:

Reference(s): **F1/T1/S6/p2-3**

It is stated that: "While spending on emergency maintenance in 2008 was impacted by the reduction in adverse weather experienced in that year as shown in Figure 1 below; overall adverse weather is trending upward. Moreover, the frequency of localized volatile weather conditions is increasing. As a result, the budget for emergency maintenance in 2009 has been increased by $0.4 million above 2008 spending."

Please state the basis for the statements above that overall adverse weather is trending upward and the frequency of localized volatile weather conditions is increasing. If these statements were derived from a study or studies, please state which study or studies and provide a brief overview of any such studies and their key conclusions.

Please provide a breakdown of emergency spending costs on an equivalent basis to that of Table 1 for the years 2004 to 2007.

RESPONSE:

a) THESL is not aware of any climatic analyses/studies that cover a time interval of this short duration. THESL has however recognised an unusually large volume of plant damage caused by weather related incidents in 2008 despite the anomalous lack of major event days during that year. On this basis an increase in 2009 emergency maintenance spending is warranted.

b) Below is a breakdown of emergency spending costs on an equivalent basis to that of Table1 for the years 2005 to 2007 only. Equivalent 2004 data is not available.

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Table 1: Emergency Maintenance Costs 2005 -2007 ($ millions)

Emergency	2005	2006	2007
OH/UG DISTRIBUTION ASSETS	6.67	6.54	6.26
STATION ASSETS	0.30	0.37	0.28
EXTERNAL CONTRACTS	N/A	N/A	N/A
TOTAL	6.97	6.91	6.54

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INTERROGATORY 21:

Reference(s): F1/T2/S1/p3

Table 1 presents Fleet and Equipment Services ("FES") costs for 2008 Historical, 2009 Bridge and 2010 Test years. Please provide these numbers for the years 2004 to 2007.

RESPONSE:

The operating expenses for Fleet and Equipment Services for the years 2004 to 2007 are listed in Table 1.

Table 1: Operating Expenses for Equipment Services 2004 -2007 ($ millions)

	2004	2005	2006	2007
FES Costs	7.1	9.2	8.1	9.6

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INTERROGATORY 22:

Reference(s): F1/T2/S1/p5

Table 1 presents Laboratory Service Operating Costs for 2008 Historical, 2009 Bridge and 2010 Test years. Please provide these numbers for the years 2004 to 2007.

RESPONSE:

The operating expenses for Laboratory Services are listed in Table 1 for the years 2005 to 2007 only.

Table 1: Operating Expenses for Laboratory Services 2005 -2007 ($ millions)

	2005	2006	2007
Glove Lab	0.8	1.0	1.1

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INTERROGATORY 23:

Reference(s): Exhibit F1, Tab 7, Schedule 1, page 6

When discussing the increase in customer service costs, it is stated that among the items responsible for the increase in 2009 year-end costs is "$1.90 million in the bad debt account. (In 2008, the bad debt provision was re-established, increasing $1.90 million in the bad debt account. This required a decrease of $1.90 million in the bad debt provision. The actual bad debt is tracking to the estimated provision.)"

When discussing the increase in the 2010 budget increase, the explanatory factors include: "$1.00 million for bad debt due to the increase in delinquent accounts as a result of a downturn in the economy."

Please provide a more detailed explanation as to the reasons for the establishment of this bad debt account including an explanation as to why the account was established at a level of $1.9 million and why it is increased by $1 million in the 2010 forecast. Please state how the $1 million increase was quantified in the context of the stated increase in delinquent accounts resulting from the economic downturn.

RESPONSE:

a) A bad debt account is established to carry an estimate for the current year of the expected amount of delinquent accounts that will become bad debt and be written off in the following year. The bad debt account for 2008 was not established at $1.90 million; it was decreased by $1.90 million.

In 2008, the methodology to estimate the provision for bad debt was re-established,

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resulting in a reduction to the provision of the bad debt account by $1.9 million. Therefore, operating expenses were lower in 2008 by $1.9 million. In 2009, the bad debt account returned to the normal level. Therefore, the 2009 operating expense for the bad debt account increased by $1.9 million.

b) In 2010, bad debt is expected to increase over 2009 by $1.00 million (note: see Exhibit C1, Tab 4, Schedule 2, detailed analysis of economic forecast).

This $1.00 million increase is due to the impact of the economic downturn as well as other factors as outlined below:

- Toronto's unemployment rate increased from 6.9 percent in 2008 to a projected 8.4 percent in 2010. This is a leading indicator of customers' ability to pay their bills. As unemployment increases, it is predicted bad debt will increase.
- The dollar value of companies in *Companies' Creditors Arrangement Act* (CCAA) Receivership is trending over 80 percent higher for 2009 versus 2008, and it is anticipated to continue to trend upwards in 2010 resulting in an expected increase in 2010 bankruptcies.
- As customers convert to Time-of-Use rates, it is expected that the average bill amount will increase, resulting in delinquent customers having higher uncollectable balances.
- The OEB's proposed customer service code amendments (EB-2007-0722) would alter existing security deposit arrangements and extend the disconnection process timelines, allowing delinquent customers who are eventually disconnected in 2010 to have higher account balances. Higher account balances and reduced security deposits to offset delinquent accounts

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will combine to increase bad debt. This OEB proposal, originally part of the Low Income Energy Assistance Program (LEAP), was revised October 1, 2009, to extend the proposed changes to all residential customers, not just low income customers.

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INTERROGATORY 24:

Reference(s): F1/T7/S5/p5

When discussing the increase of $1.85 million in Customer Relationship Management Costs from 2009 to 2010, one of the components of this increase is stated as: "$0.22 million is a result of expected lower recoveries from Contact Voltage and CDM initiatives…"

a) Please state what is meant by "lower recoveries from Contact Voltage."
b) Please state how lower recoveries from Contact Voltage and CDM initiatives would result in higher customer relationship management costs.

RESPONSE:

a) In 2009, some Customer Services staff resources were diverted from regular duties to work on THESL's Contact Voltage Emergency tasks. The associated Customer Services Division labour costs, on a one time basis, were transferred to Reactive Maintenance. This internal cost transfer is termed a recovery.

b) 2009 actual expenditures were lower on a one time basis due to the transfer of Contact Voltage and CDM labour costs. This reduction to Customer Services labour costs will not occur in 2010.

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INTERROGATORY 25:

Reference(s): F2/T3/S1/p1

It is stated that: "The 2010 amount also reflects a contribution to the new OEB initiative known as the Low Income Energy Program ("LEAP"). An anticipated change for 2010 is the Low-Income Energy Assistance Program ("LEAP") currently being proposed."

Please state the amount that is included in the 2010 Test Year for the Low-Income Energy Assistance Program. Please provide a breakdown of the amount and identify the amounts that relate to existing and new program(s).

RESPONSE:

On September 28, 2009, utilities were notified by the Ontario Energy Board ("OEB") that the Low-income Energy Assistance Program ("LEAP") would not proceed as planned in 2010. Under the former LEAP program the OEB would have required a contribution of 0.12 percent of a utility's revenue requirement for direct financial assistance to low income customers. THESL had budgeted accordingly, and included $600,000 (0.12% x $500M) for this purpose in this application.

As a result of the indefinite LEAP postponement, and following the OEB's direction to continue to provide existing financial assistance programs under existing funding arrangements, THESL intends to continue to deliver its Winter Warm Program in 2010 (in place of LEAP) under the historically approved funding level of $100,000. The $500,000 reduction will be reflected in the revenue requirement at the time of rate finalization.

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INTERROGATORY 26:

Reference(s): F2/T5/S1/p1

Table 1 on this page provides a breakdown of THESL's Finance A&G costs. This table shows total levels of $4.3 million for 2008 Historical, $4.5 million for 2009 Bridge and $10.0 million for 2010 Test. Please break down the increases for 2009 Bridge versus 2008 Historical, and 2010 Test versus 2009 Bridge into two components: (1) component of the increase related to costs previously charged as THC Shared Services functions recorded in Governance now charged to Finance as part of the reorganization, and (2) remaining component not related to this reorganization and the factors explaining this element of the increase.

RESPONSE:

Please see Appendix A, Table 1 and 2 of this Schedule.

The increase of THESL's Finance A&G costs for 2010 Test versus 2009 Bridge is driven by:

1) $5.4 million relates to THC/THESL reorganization
2) $0.2 million relates to remaining component not related to reorganization (See Appendix A).

THESL Finance A&G Costs ($ millions)

Table 1

	2008 Historical	2009 Bridge	Increase/(Decrease)	Comments
(1) Component Related to Costs Previously Charged as THC Shared Services				
Planning and Reporting	0.0	0.0	0.0	
Corporate Tax	0.0	0.0	0.0	
Internal Audit	0.0	0.0	0.0	
Total	**0.0**	**0.0**	**0.0**	
(2) Remaining Component not Related to Reorganization				
Controllership	0.7	0.7	0.0	
Planning and Reporting	1.9	2.1	0.2	
Accounts Payable	1.0	1.0	0.0	
Payroll	0.7	0.7	0.0	
Total	**4.3**	**4.5**	**0.1**	
TOTAL	**4.3**	**4.5**	**0.1**	

Table 2

	2009 Bridge	2010 Test	Increase/(Decrease)	Comments
(1) Component Related to Costs Previously Charged as THC Shared Services				
Planning and Reporting	0.0	2.4	2.4	
Corporate Tax	0.0	1.4	1.4	
Internal Audit	0.0	1.6	1.6	
Total	**0.0**	**5.4**	**5.4**	
(2) Remaining Component not Related to Reorganization				
Controllership	0.7	0.5	-0.2	As referred in Exhibit F2/T5/S1/p2. Decrease is primarily due to the transfer of employee fitness allowance costs to Organizational Effectiveness.
Planning and Reporting	2.1	2.4	0.3	As referred in Exhibit F2/T5/S1/p3. Increase is reflective of the additional resources required to support the expanded capital program and related operational and support activities.
Accounts Payable	1.0	1.1	0.1	
Payroll	0.7	0.7	0.0	
Total	**4.5**	**4.7**	**0.2**	
TOTAL	**4.5**	**10.0**	**5.6**	

Note: Exhibit F2, Tab 5, Schedule 1, page 3 is incorrect. There are no IFRS costs in the 2010 revenue requirement.

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INTERROGATORY 27:

Reference(s): **F2/T6/S1/p3**

On this page, the costs for the Treasury, Rates and Regulatory Affairs groups are shown.

a) Please provide a breakdown of the total $1.6 million increase in the 2010 Test year versus 2008 Historical for Treasury, Rates and Regulatory Affairs between these three groups and an explanation of the components of this increase for each of these departments.

b) Please provide a breakdown of THESL's regulatory costs in the format of Appendix 2-I of Chapter 2 of the Board's "Filing Requirements for Transmission and Distribution Applications."

RESPONSE:

a) Provided below is a breakdown of the total $1.6 million increase:

2008 Historical	**7.2**
Treasury	
Foreign Exchange Conversion (credit in 2008, budgeted at zero for 2010)	0.5
External Contracted Services: mainly due to consulting Legal Fees for OEB filing	0.2
Rates & Regulatory Group	
Increase primarily due to addition of staff in Rates group	0.4
Labour recovery for employee time that was previously charged to the CIS and CC&B company wide projects	0.2
OEB Annual Fixed Costs increase	0.4
2010 Test	**8.8**

b) THESL does not capture regulatory costs in a manner than can be broken down into the format of Appendix 2-I of Chapter 2 of the Board's Filing Requirements.

THESL has a small Regulatory Affairs department which is integrated with its

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Treasury and Rates departments, whose actual and forecast costs are presented in Exhibit F2, Tab 6, Schedule 1, page 3. The Regulatory Affairs department 2008 Historical, 2009 Bridge and 2010 Test Years are presented below in Table 1.

Table 1: Regulatory Affairs Department ($ Millions)

Regulatory Affairs	2008 Historical	2009 Bridge	2010 Test
Payroll Costs	0.89	0.93	1.06
Labour Costs	-	0.00	0.00
Vehicle Costs and Fleet Charges	-	0.00	0.00
Inventory and Direct Purchases	0.01	0.00	0.00
External Contract Services	0.38	0.35	0.37
Utilities and Communications	0.00	0.00	0.00
Office Supplies and Postage	- 0.00	0.01	0.01
Employee Expenses	0.03	0.05	0.06
Rental and Leases	-	0.00	0.00
Other Support Costs	3.48	3.75	3.85
Total Usage Charges	0.24	0.20	0.18
Operating Expenses	**5.03**	**5.30**	**5.54**

Certain Costs are broken out and the 2008, 2009 and 2010 amounts are presented in Table 2.

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Table 2: Costs ($)

<table>
<tr><th>Expenses</th><th>2008 Actual</th><th>2009 Bridge</th><th>2010 Test</th></tr>
<tr><td>OEB Annual Assessment</td><td>3,124,221</td><td>3,500,000</td><td>3,500,000</td></tr>
<tr><td>OEB Hearing Assessments – THESL-initiated</td><td>44,907</td><td rowspan="4">250,000</td><td rowspan="4">350,000</td></tr>
<tr><td>OEB Section 30 Costs – OEB-initiated</td><td>17,430</td></tr>
<tr><td>Annual Registration fee for THESL’s distribution licence</td><td>800</td></tr>
<tr><td>Intervenor Costs</td><td>291,890</td></tr>
<tr><td>Legal Costs for Regulatory Matters [1]</td><td>108,613</td><td>0</td><td>0</td></tr>
<tr><td>Consultant Costs for Regulatory Matters</td><td>267,303</td><td>350,000</td><td>364,000</td></tr>
</table>

[1] Bridge and Test Year legal costs are included in the “Consultant costs for Regulatory Matters” category.

Because THESL uses a cross-divisional team approach for preparing rate cases, answering interrogatories, etc., the associated operation costs are embedded in all departments and are not specifically tracked.

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INTERROGATORY 28:

Reference(s): F2/T9/S1/pp. 6-7

On these pages, external and contract services are discussed. Please provide the following for Historical, Bridge and Test years:

1) Identity of each company transacting with the applicant subject to the applicable materiality threshold
2) Summary of the nature of the product or service that is the subject of the transaction
3) Annual dollar amount related to each company (by transaction)
4) A description of the specific methodology used in determining the vendor (including a summary of the tendering process/cost approach, etc.)

RESPONSE:

1) Listed below in Table 1 are each company transacting with THESL, using a threshold of $100K per year. Included in the list are those companies which have transactions exceeding the threshold in at least one of the three years. The numbers have been aggregated to avoid any commercial confidentiality breaches.

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Table 1: List of companies transacting with THESL:

Nature of Product or Service	Supplier Name	2008 - Historical ($M)	2009 - Bridge ($M)	2010 Budget ($M)
Communication Providers	• Bell Canada • Cogeco • Industry Canada • Rogers Wireless	1.22	1.91	1.07
Consulting Service Providers	• Deloitte • Extensys • IBM Canada Ltd. • Ilantus • SBR • Tenet	1.55	0.87	0.92
Hardware Maintenance Services	• Cisco • EMC Corporation of Canada • Hewlett Pakard Canada • IBM Canada Ltd • Netezza • Softchoice Corporation	0.89	0.81	0.85
Staff Augmentation Providers	• Compu-source Staffing Inc. • CSI Consulting Inc. • Infotek Consulting Services Inc. • Integrated Voice Services Inc. • Procom Services • PTC Accounting • Quantum Technology Recruiting • Sapphire Technologies Canada	2.76	4.36	2.86
Outsourcing Services	• IBM Canada Ltd. • Kubra Data Transfer Ltd. • Unisys Canada Inc.	1.27	0.59	1.10

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Nature of Product or Service	Supplier Name	2008 - Historical ($M)	2009 - Bridge ($M)	2010 Budget ($M)
Software Maintenance Services	• Bentley • BMC Software Canada Inc. • Compuware Corporation • Emeter • Hewlett-Packard Canada • Hyperion • Intergraph Canada Ltd. • Itron Canada Inc. • McAfee • Mincom Inc. • Novell Canada Ltd. • Oracle Corporation Canada • Open Storage Solutions • Redhat, Inc. • The Herjavec Group • Whitecap Canada Inc.	2.53	3.03	4.90

2) Listed above in Table 1 is the summary of the nature of the product or service that is the subject of the transaction.

3) Listed above in Table 1 is the annual dollar amount related to each product or service.

4) IT&S follows the THESL procurement policy, as per Exhibit C2, Tab 3, Schedule 1,, Appendix A.

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INTERROGATORY 29:

Reference(s): F2/T9/S1/pp. 6-7

It is stated that: "Major implementation of the new CIS system, SAP for the support of new IFRS requirements, Data Warehousing/Business Intelligence and the Identity and Access Management software, amongst others, result in net new increases to THESL operating costs beginning in 2010, totalling a $2.4 million increment to the maintenance contracts."

Please provide a breakdown of the referenced $2.4 million increment between these projects and any necessary explanations.

RESPONSE:

The majority of the $2.4 million increase in maintenance cost is due to the introduction of net new initiatives. As shown in the following table, the remainder is the result of increased user license or extended support requirements which, in turn, increase the annual maintenance costs.

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1 **Table 1: 2010 Maintenance Cost Increases by System**

IT Program	2010 Test Year Increase ($ millions)	Reason for Increase
Identity Access Management	0.18	New system introduction
Business Intelligence	0.48	New system introduction and initial usage estimates
Customer Information System	0.72	New system introduction
SAP Implementation	0.40	New system introduction
Service Oriented Architecture	0.18	New services introduction
Others	0.42	Increase in user licenses or extend support requirements for Ellipse, Bentley (Microstation, Project Wise), etc.
TOTAL	$ 2.38	

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INTERROGATORY 30:

Reference(s): F2/T9/S1/pp.6-7

It is stated that: "In order to minimize rising maintenance costs as a result of these initiatives, operational projects continue in consolidating legacy applications and servers. Other measures taken to maintain and lower costs include longer term agreements and negotiating recessionary pricing on vendor offerings."

Please provide examples of these other measures and the types of savings that have been achieved.

RESPONSE:

Provided below are three examples of our actions to minimize rising maintenance costs during the past year.

1) The Wireless plan costs including support for Blackberry devices, cell phones, and pagers, is an example of THESL reducing costs through the competitive bid process. An RFP process provided proposals from the major telecom companies producing a winning bid that will deliver 20% savings (approximately $340K) from current costs of $1.7M.

2) For the computer hardware and software maintenance covering the IBM P-Series servers, the original annual maintenance was $443K. Through negotiations to consolidate several contracts and simplify their administration over the next three years, the annual maintenance cost will now be reduced to $354K providing annual

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savings of $88K for each of the next three years.

3) In December of 2007 a decision was made to move from a managed services Client Support Services model to a hybrid model because of an erosion of service from our supplier Unisys. The following services were brought in-house: desk side support, asset management, printer management, PC image management and computer refresh. This resulted in an annual saving of $300k starting in 2009 and greatly increased client satisfaction.

4) In 2009, support for the THESL IT Help Desk was put to competitive RFP process. Four vendors participated, and the contract was awarded to IBM resulting in further annual savings of approximately $40K or 11.8% over the existing contact.

5) In addition, significant strides have been made in virtualizing many of the servers in the Data Center. Savings are estimated are about $273K for the first year, and a further $124 K for the second year, in addition to incremental savings of about $3K per server

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INTERROGATORY 31:

Reference(s): F2/T10/S1/p.7

Table 4 “HR Services Costs” shows an increase in these costs from $1.9 million in 2008 to $3.2 million for the 2010 Test year, or $1.3 million.

Please provide a breakdown of the components of this increase including 2010 Test/2009 Bridge Inflation, 2009 Bridge/2008 Inflation and a breakdown of “Increase in costs for attraction and recruiting of hires into trades, technical and leadership positions” for each of these year over year comparisons, as well as an explanation as to the costs which are encompassed in this category.

RESPONSE:

Breakdown for 2010 Test/2009 Bridge – Year over Year variance $500K:

- 3% increase assumed for general inflation of approximately $40K
- Cost for additional HR Services resources of $415
- Increased recruitment cost of $60K
- Increased job advertisement cost of $120K
- Decreased legal costs of $170K
- Decreased cost from 2009 for collective agreement printing of $10K

Breakdown for 2009 Bridge/2008 Inflation – Year over Year variance $742K:

- 2.4% increase assumed for general inflation of approximately $25K
- Cost for additional HR Services staff of $180K
- Increased recruitment cost of $90K

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- Addition of $520K for labour relations related legal costs (previously held in Legal Services budget)
- Decreased cost for job advertisement of $20K
- Decreased cost from 2008 related to collective bargaining of $40K

Recruitment costs include professional services fees for external recruiters, background checks as well as occupational/skills testing and assessment.

Job advertisement costs include costs for newspaper job ads, on-line job board postings, participation in job/career fairs and job/career ads in industry and educational institution publications.

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INTERROGATORY 32:

Reference(s): C1/T3/S1

Please complete the following table for 2008 Historical, 2009 Bridge and 2010 Test years for each service provided or received by THESL:

Year						
Name of Company		Service Offered	Pricing Methodology	Price for the Service ($)	Cost for the Service ($)	% Allocation
From	To					

RESPONSE:

Please see Appendix A of this Schedule.

Appendix A
Services Provided or Received by THESL

2010 Test						
Name of Company						
From	**To**	**Service Offered**	**Pricing Methodology**	**Price for the Service ($)**	**Total Cost for the Service ($)**	**% Allocation**
THESL	THC	Facilities	Based on sq footage	$ 77,879	$ 25,254,368	0.3%
THESL	THC	IT-Management Services	Based on # of users and FTE	$ 29,460	$ 32,210,562	0.1%
Total SS from THESL to THC				**$ 107,339**	**$ 57,464,930**	
				-		
THC	THESL	Governance	Based on directly attributable costs, balance based on time study results.	$ 1,500,897	$ 2,004,074	74.9%
THC	THESL	Finance	Based on directly attributable costs, balance based on time study results.	$ 742,137	$ 818,758	90.6%
Total SS from THC to THESL				**$ 2,243,033**	**$ 2,822,832**	
				-		

2009 Bridge

Name of Company From	To	Service Offered	Pricing Methodology	Price for the Service ($)	Cost for the Service ($)	% Allocation
THESL	THC	Procurement Charge	Based on # of purchase orders	$ 16,971	$ 2,077,417	0.8%
THESL	THC	Facilities	Based on sq footage	$ 549,087	$ 25,056,399	2.2%
THESL	THC	AP and Related Services	Based on # Invoices Processed	$ 11,840	$ 1,044,603	1.1%
THESL	THC	Payroll processing and related activities	Based on FTE	$ 13,509	$ 697,627	1.9%
THESL	THC	Treasury, Rates & Regulatory	Based on % of work performed	$ 550,185	$ 11,524,097	4.8%
THESL	THC	OE - Planning, Benefits and Compensation	Based on # of Employees	$ 21,578	$ 876,364	2.5%
THESL	THC	OE - Services	Based on # of Employees	$ 87,400	$ 2,193,393	4.0%
THESL	THC	OE-ORG DEVT & PERFORMANCE	Based on # of Employees	$ 62,335	$ 2,917,519	2.1%
THESL	THC	OE-PROJECT SUPPORT OFFICE	Based on # of Employees	$ 10,258	$ 108,469	9.5%
THESL	THC	Legal Commercial	Based on % of work performed	$ 14,428	$ 663,251	2.2%
THESL	THC	Litigation	Based on % of work performed	$ 1,030	$ 443,259	0.2%
THESL	THC	Real Property	Based on % of work performed	$ 286	$ 527,841	0.1%
THESL	THC	Communications & Public Affairs	Based on time estimates	$ 270,357	$ 3,836,747	7.0%
THESL	THC	IT-Management Services	Based on # of users and FTE	$ 482,305	$ 28,951,921	1.7%
Total SS from THESL to THC				**$ 2,091,569**	**$ 80,918,907**	
				-		
THC	THESL	Governance	Based on directly attributable costs, balance based on time study results.	$ 75,628	$ 1,354,718	5.6%
THC	THESL	Finance	Based on directly attributable costs, balance based on time study results.	$ 6,942,563	$ 9,284,553	74.8%
THC	THESL	Legal	Based on directly attributable costs, balance based on time study results.	$ 661,030	$ 1,336,084	49.5%
THC	THESL	Communications	Based on directly attributable costs, balance based on time study results.	$ 213,807	$ 907,736	23.6%
THC	THESL	Organization Effectiveness & EHS	Based on directly attributable costs, balance based on time study results.	$ 649,050	$ 887,999	73.1%
Total SS from THC to THESL				**$ 8,542,079**	**$ 13,771,090**	
				-		

2008 Historical

Name of Company From	To	Service Offered	Pricing Methodology	Price for the Service ($)	Cost for the Service ($)	% Allocation
THESL	THC	Procurement Charge	Based on # of purchase orders	$ 27,893	$ 1,445,928	1.9%
THESL	THC	Facilities	Based on sq footage	$ 591,309	$ 24,650,048	2.4%
THESL	THC	AP and Related Services	Based on # Invoices Processed	$ 11,371	$ 1,008,312	1.1%
THESL	THC	Payroll processing and related activities	Based on FTE	$ 13,789	$ 694,500	2.0%
THESL	THC	Treasury, Rates & Regulatory	Based on % of work performed	$ 455,737	$ 9,866,592	4.6%
THESL	THC	OE - Planning, Benefits and Compensation	Based on # of Employees	$ 14,684	$ 775,841	1.9%
THESL	THC	OE - Services	Based on # of Employees	$ 30,111	$ 1,923,023	1.6%
THESL	THC	OE-ORG DEVT & PERFORMANCE	Based on # of Employees	$ 40,894	$ 2,756,298	1.5%
THESL	THC	OE-PROJECT SUPPORT OFFICE	Based on # of Employees	$ 9,843	$ 464,558	2.1%
THESL	THC	Legal Commercial	Based on % of work performed	$ 18,532	$ 727,980	2.5%
THESL	THC	Litigation	Based on % of work performed	$ 1,455	$ 455,849	0.3%
THESL	THC	Communications & Public Affairs	Based on time estimates	$ 297,158	$ 4,409,260	6.7%
THESL	THC	IT-Management Services	Based on # of users and FTE	$ 482,104	$ 28,190,066	1.7%
Total SS from THESL to THC				**$ 1,994,880**	**$ 77,368,255**	
				$ 0		
THC	THESL	Governance	Based on directly attributable costs, balance based on time study results.	$ 1,307,447	$ 2,626,499	49.8%
THC	THESL	Finance	Based on directly attributable costs, balance based on time study results.	$ 5,007,372	$ 7,762,864	64.5%
THC	THESL	Organization Effectiveness & EHS	Based on directly attributable costs, balance based on time study results.	$ 599,660	$ 777,395	77.1%
THC	THESL	Legal	Based on directly attributable costs, balance based on time study results.	$ 636,650	$ 1,300,636	48.9%
THC	THESL	Communications	Based on directly attributable costs, balance based on time study results.	$ 243,046	$ 1,030,473	23.6%
Total SS from THC to THESL				**$ 7,794,175**	**$ 13,497,868**	

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INTERROGATORY 33:

Reference(s): **C1/T3/S1/p.1**

It is stated that: "On August 17, 2009, the Chair of the Board of Directors of Toronto Hydro Corporation announced that Mr. David O'Brien would retire as the Chief Executive Officer of Toronto Hydro Corporation effective September 30, 2009, and would be succeeded by Mr. Anthony Haines, who would in addition retain his role as President of THESL. Changes in 2010 governance costs may follow from this announcement. However, given the timing of the filing of this Application, it was not possible to reflect any cost changes that may arise in pre-filed evidence. To the extent that any such changes in planned costs become known prior to the end of the hearing, THESL will advise the Board, and incorporate any necessary changes during rate finalization."

a) Please provide an update as to whether or not THESL would anticipate any changes to 2010 governance costs following from this announcement and, if so, when such changes would be filed.

b) Please clarify what is meant by the statement that THESL would "incorporate any necessary changes during rate finalization" including whether this statement implies that such changes would be filed during the evidentiary phase of the proceeding, or subsequently.

RESPONSE:

a) Please see Exhibit R1, Tab 11, Schedule 3, the response to VECC 3 a).

b) THESL intends to incorporate any necessary changes subsequent to the evidentiary phase of the proceeding, along with other changes that could result from the testing of

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the evidence.

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INTERROGATORY 34:

Reference(s): C1/T3/S1/p.2

It is stated that: "Consequently, services purchased by THESL from THC will be $2.4 million in 2010, comprised of $1.7 million for strategic leadership, stewardship and governance, and $0.7 million for overall finance leadership to the organization. These services will be performed by the Board of Directors, offices of the Chief Executive Office and the Chief Financial Officer."

Please state the headcount underlying both of these costs.

RESPONSE:

Board of Directors – not part of headcount
Chief Executive Office – two FTE (CEO and Admin)
Chief Financial Officer – two FTE (CFO and Admin)

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INTERROGATORY 35:

Reference(s): **C1/T3/S1/pp.2-3 & App. B**

It is stated that: "As a result of the divestitures of most unregulated activities discussed above, the amounts that THESL will sell to TH Energy will decrease from 2009 to 2010." Please state why the referenced divestitures will result in a decrease in the amounts that THESL will sell to TH Energy from 2009 to 2010 and whether this is the only factor explaining the decrease from $1.77 million in the 2009 Bridge year to $1.41 million in the 2010 Test year.

RESPONSE:

The decrease of $0.34 million that THESL will sell to TH Energy from 2009 to 2010 is generally attributable to the reduction of Treasury services provided to TH Energy as a result of the referenced divestitures. In 2010, Treasury will provide limited financing strategies, cash management, credit and debt management, investor relations and insurance and risk management services to TH Energy.

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INTERROGATORY 36:

Reference(s): **C2/T1/S2**

Please complete the following table:

	2004A VS 2003A	2005A VS 2004A	2006A VS 2005A	2007A VS 2006A	2008A VS 2007A	2009B VS 2008A	2010T VS 2009B
Yearly Market Adjustment/General Increase (%)							
Headcount increase (%)							
Total Compensation Capitalized (%)							

Note: For "Total Compensation Capitalized" please provide the percentage for the year in question, not a year versus year comparison. For the other two columns, please provide the year over year change. A=Actual, B= Bridge, T=Test Year

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RESPONSE:

	2004A VS 2003A	2005A VS 2004A	2006A VS 2005A	2007A VS 2006A	2008A VS 2007A	2009B VS 2008A	2010T VS 2009B
Yearly Market Adjustment/General Increase (%)	3%	3%	3.5%	3.25%	3.25%	3%	3%
Headcount increase (%)	-2%	7%	3%	11%	1%	5%	9%
Total compensation capitalized (%)	45%	46%	50%	44%	46%	46%	47%

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INTERROGATORY 37:

Reference(s): C2/T1/S2/p.2

It is stated that: "As part of THESL's new five-year Collective Agreement with CUPE effective February 1, 2009, a group incentive program was introduced for unionized employees in the critical front-line roles of Crew Leader and System Response Representative. This new Gain Sharing Program is a groundbreaking achievement, linking pay to successful delivery of specific results."

Please state whether the adoption of this program is expected to result in any cost savings to THESL. If yes, please state the amount. If no, please state the additional costs arising from it.

Please discus how THESL determined that it would adopt the Gain Sharing Program. In responding, please state whether the Gain Sharing Program, or a similar program has to THESL's knowledge, been adopted by any other utilities and, if so, what their experience with it has been.

RESPONSE:

Gain Sharing is a group incentive plan that is focused on driving organizational performance improvement specifically in the areas of injury reduction, increased attendance, improved productivity and enhanced service reliability. Payout of the Gain Sharing award requires the achievement of targets for individual Key Performance Indicators ("KPIs") on the Gain Sharing scorecard. This scorecard is a subset of the THESL scorecard, thereby linking performance and payout to business results. This program is expected to improve operational performance and mitigate cost increases.

The additional cost arising from the Gain Sharing program is estimated to be $260,000 if participants achieve target for all four KPIs on the 2009 Gain Sharing scorecard.

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THESL determined that it would adopt the Gain Sharing Program in an effort to tie a portion of each employee's compensation with organizational performance. THESL is aware of four utilities that have gainsharing programs: Enbridge Gas Distribution Inc., EPCOR Utilities Inc., B.C. Hydro and Union Gas Limited. The experience shared with THESL is that their gainsharing program has assisted in employee engagement and morale improvement and has had a positive impact on customer service ratings.

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INTERROGATORY 38:

Reference(s): C2/T1/S2/App. A/p.1

Please provide an extended version of Table 1: Employee Compensation including 2004 to 2007 Actuals.

RESPONSE:

The extended version of the Employee Compensation is shown in Table 1. Please see Appendix A of this Schedule.

TABLE 1: EMPLOYEE COMPENSATION (EXTENDED VERSION)

	2004	2005	2006	2007	2008 Board Approved	2008 Historical Actual	2009 Bridge	2010 Test
Number of Employees (FTEs including Part-Time)								
Executive	5	5	6	10	10	10	9	12
Managerial	21	24	21	38	47	41	47	51
Management/Non-Union	129	142	137	265	291	275	310	396
Union *	1,062	1,135	1,187	1,212	1312	1220	1265	1326
Total *	1,216	1,306	1,351	1,525	1660	1546	1630	1785
** Excludes President & Vice President of CUPE Local One*								
Number of Part-Time Employees								
Executive								
Management (Managerial)								
Non-Union (Management/Non-Union)								
Union								
Total								
Total Salary and Wages								
Executive	826,405	863,828	1,105,452	1,714,398	1,781,361	1,812,508	1,677,709	2,345,675
Managerial	2,288,033	2,769,324	2,533,230	4,679,679	5,769,534	4,960,743	5,953,672	6,791,285
Management/Non-Union	10,462,409	11,936,095	11,860,501	23,652,288	26,715,188	24,637,246	30,478,810	37,133,674
Union	67,075,124	75,167,804	80,321,916	85,537,115	95,418,487	88,723,958	96,095,110	102,584,925
Total	**80,651,971**	**90,737,052**	**95,821,099**	**115,583,480**	**129,684,570**	**120,134,455**	**134,205,301**	**148,855,559**
Total Benefits								
Executive	332,335	305,275	436,776	667,994	829,925	818,469	833,806	1,126,847
Managerial	809,101	833,933	917,973	1,616,795	2,054,872	1,690,280	2,127,067	2,473,102
Management/Non-Union	3,742,596	3,624,597	4,140,551	8,208,444	9,467,340	8,509,707	10,915,727	13,740,209
Union	24,642,723	23,303,880	29,213,257	30,339,717	33,542,681	30,960,867	33,867,173	37,392,403
Total	**29,526,754**	**28,067,685**	**34,708,557**	**40,832,950**	**45,894,818**	**41,979,324**	**47,743,773**	**54,732,561**
Total Compensation (Salary, Wages, & Benefits)								
Executive	1,158,740	1,169,103	1,542,228	2,382,392	2,611,286	2,630,977	2,511,515	3,472,522
Managerial	3,097,134	3,603,257	3,451,203	6,296,474	7,824,406	6,651,023	8,080,739	9,264,387
Management/Non-Union	14,205,005	15,560,692	16,001,052	31,860,731	36,182,529	33,146,953	41,394,537	50,873,883
Union	91,717,846	98,471,684	109,535,173	115,876,832	128,961,168	119,684,825	129,962,283	139,977,328
Total	**110,178,725**	**118,804,736**	**130,529,656**	**156,416,429**	**175,579,389**	**162,113,778**	**181,949,074**	**203,588,120**
Compensation - Average Yearly Base Wages								
Executive	165,281	172,766	184,242	171,440	178,136	181,251	186,412	195,473
Managerial	110,533	115,389	120,630	122,689	122,756	121,783	126,674	132,642
Management/Non-Union	81,293	84,153	86,573	89,247	91,773	89,665	98,478	93,725
Union	63,189	66,243	67,668	70,575	72,711	72,700	75,995	77,382
Compensation - Average Yearly Overtime								
Executive		-		-	0	0	0	0
Managerial		-		-	0	0	0	0
Management/Non-Union	4,285	5,512	7,307	4,841	3,547	4,297	2,371	3,873
Union	4,905	8,148	10,157	12,534	7,081	9,498	11,027	10,095
Compensation - Average Yearly Incentive Pay								
Executive	51,810	55,166	50,143	59,643	74,817	70,902	85,746	66,474
Managerial	13,121	14,701	14,662	18,344	19,409	22,732	26,474	23,477
Management/Non-Union	4,368	4,497	4,721	5,114	7,450	6,769	7,891	8,161
Union**	4,568	4,862	3,396	4,890	7,497	5,063	6,583	3,421
***Only inlcudes The Society of Energy Professional, Crew Leaders, System Response Rep*								
Compensation - Average Yearly Benefits								
Executive	66,467	61,055	72,796	66,799	82,993	81,847	92,645	93,904
Managerial	39,087	34,747	43,713	42,388	43,721	41,495	45,257	48,303
Management/Non-Union	29,080	25,554	30,223	30,973	32,523	30,970	35,269	34,680
Union	23,215	20,537	24,611	25,033	25,560	25,369	26,783	28,206
All Inclusive (Base Wages, Overtime, Incentive Pay, Benefits)								
Total Compensation	117,129,738	130,186,689	144,823,642	175,664,371	189,939,036	178,510,702	201,289,096	224,289,279
Total Compensation Charged to OM&A	64,784,458	70,951,746	72,382,856	98,090,985	108,531,165	96,609,992	108,756,499	119,815,333
Total Compensation Capitalized	52,345,280	59,234,944	72,440,786	77,573,386	81,407,871	81,900,710	92,532,597	104,473,946

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INTERROGATORY 39:

Reference(s): C2/T1/S2/App. A/p.1

At Line 32 of Table 1, which provides a breakdown of employee compensation, a number is provided for "Total Compensation (Salary, Wages & Benefits)" which for the 2010 Test Year is $203,588,120.

At Line 55 of the same Table, a number is provided for "Total Compensation" which for the 2010 Test Year is $224,289,279.

Please state the reason for the difference in these two numbers.

RESPONSE:

Line 32 of Table 1, provides "Total Compensation" that includes Salary, Wages and Benefits costs only (as specified in the template). Line 55 of the same Table 1 provides "Total Compensation" that includes Base Wages, Overtime, Incentive Pay, and Benefits costs (as specified in the template). The difference is the inclusion of Overtime and Incentive Pay on Line 55.

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INTERROGATORY 40:

Reference(s): C2/T1/S2/App. A/p.1

"Total Compensation" at line 55 of Table 1 is shown as $224,289,279 for the 2010 Test year and $201,289,096 for the 2009 Bridge year. Please provide a breakdown of the $23 million increase between the yearly market adjustment/general increases and the expected increase in headcount.

RESPONSE:

The majority of the increase between 2009 Bridge year and 2010 Test year is related to the anticipated integration of 33 THC employees and additional costs are attributed to the 194 new hires (FTE) planned for 2010, base salary increases and related benefit costs.

Breakdown of the $23 Million

Descriptions	$ (Million)
33 THC	$5.0
194 FTE New Hire	$13.5
General Increases and Related Benefit Costs	$4.4
TOTAL	$23.0

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INTERROGATORY 41:

Reference(s): C2/T1/S3/p.2

Table 2 provides "Post-Retirement Benefits Costs" for 2008 Actual, 2009 Bridge and 2010 Test years. Please provide an equivalent table for 2004 to 2007 Actuals.

RESPONSE:

Table 2: Post-Retirement Benefits Costs ($ Millions)

Post Retirement Benefits	2004 Actuals	2005 Actuals	2006 Actuals	2007 Actuals
Post Retirement Benefits Cost	10.0	11.1	13.1	13.4
Less: Amount Capitalized	3.0	3.7	6.4	5.6
Amount Expensed In Each Year	**7.0**	**7.4**	**6.7**	**7.8**

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INTERROGATORY 42:

Reference(s): **C1/T1/S4/p.6**

Page 6 of the Compensation Program Guide contains 2009 weightings for various positions in THC and THESL.

a) Please provide definitions of the columns "Individual Performance," "Affiliate Performance," and "Corporate Performance."

b) Please explain the percentage allocations for each of the employee categories under "Affiliate Performance." (e.g., please state why managers at THESL would be assigned a 30% weighting for affiliate performance and similarly for the other percentages in this column)

c) Please state whether THESL's reorganization is expected to impact these percentages in 2010 and, if so, to what extent.

RESPONSE:

a) "Individual Performance" refers to the weighting or percentage of total direct pay award that will be paid based on achievement of performance objectives as set out in the individual employee's annual performance contract and specific job expectations. "Affiliate Performance" refers to the weighting or percentage of total direct pay award that will be paid based achievement of Key Performance Indicators on the scorecard of the Affiliate. "Corporate Performance" refers to the weighting or percentage of total direct pay award that will be paid based achievement of Key Performance Indicators on the scorecard of Toronto Hydro Corporation.

b) The percentages allocated to each employee category under "Affiliate Performance" reflect their line of sight to impact results within the Affiliate. The more senior the

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position, the more influence they have on the Affiliate results and therefore a higher component of their performance pay is linked to the attainment of these goals.

c) THESL's reorganization is not expected to impact these percentages in 2010.

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INTERROGATORY 43:

Reference(s): C2/T1/S5/p.3

Table 1 on this page provides "Forecast Retirements" for the 2009 to 2018 period totaling 694 employees.

The equivalent table in THESL's EB-2007-0680 application, contained in Exhibit C2/Tab 1/Schedule 6/page 2 provides "Forecast Retirements" for the 2007 to 2016 period totaling 567 employees.

Please provide an explanation for the 22% increase in this number in the current application.

RESPONSE:

The 22 percent increase is primarily due to shifting the projection window by two years.

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INTERROGATORY 44:

Reference(s): C2/T1/S5/p.3

It is stated that: "In 2010, THESL continues with its ten-year plan to upgrade its distribution system infrastructure. In terms of the labour necessary for plan implementation, THESL projects a shortfall based on current staffing levels of approximately 350-400 full-time employees ("FTEs") in 2010."

In Exhibit C2 Tab 1 Schedule 2 Appendix A, THESL states that total FTEs for the 2010 Test year are 1,785. Please state whether, the statement quoted above would imply that THESL believes that the necessary FTE level in 2010 to upgrade its distribution system infrastructure would be the 1,785 FTEs presently on the payroll, plus an additional 350-400 employees. If yes, please explain how this number was determined. If no, please clarify what is meant by this statement.

Please include a statement as to what THESL believes the ongoing sustainable level of FTEs necessary to complete the ten-year plan would be.

RESPONSE:

The stated 350-400 employees would be required over and above the existing 1,785 FTEs presently on the payroll. This requirement was derived using our normal estimating procedures. Each project in the annual work program was estimated based on the project scope and assuming the use of internal labour resources. The overall labour requirement was then compared to the known available labour hours within our existing workforce. A shortfall of available labour resulted, and represents 350-400 FTEs.

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THESL's intent is to make up this shortfall through a combination of:

a) New staff hires
b) The use of external contract labour
c) Continuous improvements

THESL projects that the expected ongoing sustainable level of internal FTEs will be approximately 2,000 to 2,200. Staffing to this level, however, will take several years, since new hires need to be brought on board in a controlled fashion to ensure safety and effective knowledge transfer from existing staff. This estimated FTE level is also highly dependent on changes in the industry, changes to the work requirements or new initiatives that may arise, and the level of capital approved by the Board.

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INTERROGATORY 45:

Reference(s): **C2/T1/S5/p.5**

It is stated that: "To address the shortfall in labour needed to complete the 2010 Work Program, THESL has engaged 20 separate design and/or civil construction and/or electrical construction contract firms. Each attended information sessions in June 2009, wherein a high-level presentation of the Work Program was delivered and THESL's needs identified. A Request for Proposal will be issued to these contract firms in August, and approval for the winning proposals will be provided by THESL's Board of Directors in October."

a) Please provide a copy of the referenced Request for Proposal, or a summary of its key elements.

b) Please provide an update on the status of this process. If the winning proposals have been determined, please state who the winners are, what they will each be doing and the amount of the winning bid.

RESPONSE:

a) As a summary of the essential elements of the RFP, the work to be performed by the successful Respondent(s) will be turnkey projects for the design and construction of civil/electrical utility plant. This work will apply to projects issued by THESL to support the Capital Program. The RFP is based on fixed unit prices for work, including but not limited to:

    (1) The construction of civil infrastructure including trenching/tunnelling, duct structures, foundations, cable chambers, and transformer vaults;

    (2) The construction and/or maintenance of overhead and underground electrical distribution including, pole setting and framing, transformers, switches and

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switchgear, cable installation, stringing of overhead conductors, grounding, terminations/elbows/splices. Stations construction and/or maintenance including, transformers, breakers, equipment inspection and replacement, SCADA, protection and control services;

(3) The design of civil infrastructure and/or electrical distribution systems; and

(4) The acquisition and handling of electrical material.

b) THESL selected three successful respondents, Powerline Plus, Entera and Aecon. The overall projected value of work to be assigned to the three respondents will vary depending upon OEB approvals, and there is no minimum value guaranteed to the respondents.

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INTERROGATORY 46:

Reference(s): D1/T13/S1/p.1

Please state whether there have been any changes in THESL's depreciation policies since the filing of its 2008 cost of service application. If there have been any, please state what they are and provide their impact on the present application.

RESPONSE:

THESL's depreciation policies have not changed since the filing of its 2008 cost of service application.

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INTERROGATORY 47:

Reference(s): H1/T1/S1/p.7

It is stated that for 2010 versus 2009: "The decrease in PILs of approximately $7.8 million is mainly attributable to a reduction in capital taxes due to a reduction in the capital tax rate and differences between the tax and book treatment of various costs."

Please provide a table of THESL's capital taxes paid for 2004 to 2008 actuals, 2008 Board Approved, 2009 Bridge and 2010 Test years along with the applicable rates for each of these years.

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RESPONSE:

Summary of Capital tax by Year ($ millions)

	2004 Actual	2005 Actual	2006 Actual	2007 Actual	2008 Actual	2008 EDR Request**	2009 Bridge	2010 Test
Capital tax rate	0.3%	0.3%	0.3%	0.225%	0.225%	0.285%	0.225%	0.075%
Capital tax	6.2	5.8	6.6	5.2	5.4	5.9	5.4	2.0

**The Board did not approve a Capital Tax rate for 2008.

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INTERROGATORY 48:

Reference(s): H1/T1/S1/p.7

Table 2, "Summary of Property Taxes by Year" provides a breakdown of property taxes for 2008 Historical, 2009 Bridge and 2010 Test years.

a) Please expand this table to include 2004 to 2007 actuals and 2008 Board Approved.

b) Please provide an explanation for the property tax reassessment reduction of $0.9 million in the 2008 Historical year and any other reassessments that may have occurred in the 2004 to 2007 period.

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RESPONSE:

a)

Summary of Property Taxes by Year ($ millions)

	2004	2005	2006	2007	2008 Board Approved	2008 Historical	2009 Bridge	2009 Actual Projected	2010 Test
Municipal and PILs Property Taxes	9.9	10.3	7.5	6.8	7.6	6.9	6.5	6.5	6.7
Property Tax Reassessments	(1.0)	(0.9)	(4.8)	(0.6)	-	(0.9)	-	(0.1)	-
Total Property Taxes	8.9	9.4	2.7	6.2	7.6	6.0	6.5	6.4	6.7

b) The property tax reassessment reduction of $0.9 million is primarily from the successful appeal of incorrect property values and/or tax classes. Other adjustments for appeals during the preceding periods would have been recorded as received.

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INTERROGATORY 49:

Reference(s): D1/T3/S1/p.3

It is stated that, referring to 2009 Bridge versus 2008 Historical Other Distribution Expenses: "The decrease in other distribution expenses is primarily due to a one-time increase in capital taxes related to the settlement in 2008 of the 2001, 2002, 2003 and 2004 PILs audits."

Please state why capital taxes were increased on a one-time basis in 2008 due to the settlement and the amount of the one-time adjustment.

RESPONSE:

In 2008 the Ministry of Finance completed audits of THESL for the taxation years ending 2001 through 2004. In the course of the audit, THESL agreed to revise the manner in which it calculated a component of its taxable capital. The revision resulted in a net increase in capital tax of $2.017 million in 2008.

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INTERROGATORY 50:

Reference(s): H1/T1/S1/p.6

Table 1 provides a summary of PILs by year for the 2004 to 2010 period. This shows that total PILs drops from $62.7 million in 2005 to $23.4 million in 2010. Please state whether this drop can be largely attributed to reductions in tax rates, or if there are any other significant factors contributing to it. If so, please state what any other such factors would be.

RESPONSE:

The decrease in PILS illustrated in Table 1, is primarily from the decrease in income tax rates and from the removal of regulatory assets in the calculation of regulatory taxable income.

INTERROGATORIES OF ONTARIO ENERGY BOARD STAFF

INTERROGATORY 51:

Reference(s): C2/Tab1/Schedule 1

On this page, THESL provides a response to question #7, which is "Has the applicant deducted regulatory assets for tax purposes in 2008 and/or in prior years? If yes, please explain your reasons in the manager's summary." Staff notes that THESL responds "Yes" to this question but does not appear to have provided an explanation.

The Board, in a number of EDR 2008 decisions denied increasing regulatory taxable income through the addition of movements, or recoveries, in regulatory assets, e.g., Brantford Power, PUC. For instance in the Brantford Power Decision (EB-2007-0698) the Board stated that "The appropriate forum for the issues raised by the Company is the Board's pending proceeding on account 1562. Until that proceeding is concluded, there is no basis for the Board to deviate from the findings it has made in other cases where the same issue has been identified."

Please provide an explanation as to why THESL has deducted regulatory assets for tax purposes in 2008 and/or prior years and state whether such a deduction is incorporated into the 2010 PILS calculation. If it is, please provide a justification in light of the Board's findings referenced above and please also provide revised PILs calculations excluding any such amounts.

RESPONSE:

In 2008 and prior years, THESL adjusted its taxable income for regulatory assets for purposes of calculating regulatory taxable income. By calculating taxable income in this manner, the regulatory taxable income more closely resembles actual taxable income and

INTERROGATORIES OF ONTARIO ENERGY BOARD STAFF

actual taxes paid. Since 2008 THESL has followed the decision in Brantford Power and the Board proceedings on account 1562. For the 2010 PILs calculation, THESL has not adjusted its regulatory taxable income for regulatory assets in order to be in line with the Brantford Power decision and the Board's direction.

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INTERROGATORY 52:

Reference(s): P1/T2/S1/p.39

On this page THESL uses a corporate income tax rate of 33%. Please state the basis for the use of this rate and whether or not it reflects the change in the Ontario income tax rate change from 14% to 12% July 1, 2010.

If the 33% rate needs to be adjusted, please also make any necessary revisions to the application related to the lower recoverable PILs amount which would arise from this change.

RESPONSE:

THESL used the substantively enacted corporate income tax rate for 2010 that was in effect at the time of filing its application. As it did in previous applications, THESL will update its application for income tax rate changes at the time of the Board's decision in this proceeding. Any income tax rate changes that occur after the Board's decision will be recorded in THESL's PILs deferral account 1592.

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INTERROGATORY 53:

Reference(s): D1/ T1/ S1/p.3

THESL states that it has included an allowance for borrowed funds used during construction ("AFUDC") for the capital expenditure balance after 2008 as prescribed by the Board's Accounting Procedures Handbook ("APH").

Provide a brief overview of THESL's treatment of AFUDC and Construction Work in Progress (CWIP) as incorporated in this application and state whether there are any departures from the APH and, if so, why they have been made. Please include a discussion as to how CWIP is incorporated in rate base

RESPONSE:

THESL's treatment of AFUDC and CWIP is consistent with the Board's Accounting Procedures Handbook.

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INTERROGATORY 54:

Reference(s): D1/ T1/ S1

Please provide a Fixed Asset Continuity Schedule as shown in Appendix 2-C of Chapter 2 of the Filing Requirements for Transmission and Distribution Applications, issued May 27, 2009.

RESPONSE:

The Fixed Asset Continuity Schedules for the years 2008 Historical, 2009 Bridge and 2010 Test are included in Appendix A of this Schedule.

Note, of the five year historical data, the former years (2004-2007) are not available in the requested format.

Appendix A: Fixed Asset Continuity Schedule ($ millions)
Table 1: 2008 Historical

				Cost				Accumulated Depreciation				
CCA Class	OEB	Description	Depreciation Rate	Opening Balance	Additions	Disposals and Transfers	Closing Balance	Opening Balance	Additions	Disposals and Transfers	Closing Balance	Net Book Value
N/A	1805	Land	NA	2.2	-	0.0	2.2	-	-	-	-	2.2
CEC	1806	Land Rights	2.0%	1.6	0.1	-	1.7	0.2	0.0	-	0.2	1.5
47	1808	Buildings	2.0%	41.9	2.0	0.0	43.9	15.0	0.8	0.0	15.8	28.1
13	1810	Leasehold Improvements	10.0%	-	-	-	-	-	-	-	-	-
47	1815	Transformer Station Equipment >50 kV	2.5%	11.9	-	-	11.9	3.5	0.3	-	3.8	8.1
47	1820	Substation Equipment	3.3%	147.2	34.2	-	181.5	73.0	4.7	-	77.6	103.8
47	1825	Storage Battery Equipment	NA	-	-	-	-	-	-	-	-	-
47	1830	Poles, Towers & Fixtures	4.0%	312.7	13.8	-	326.5	133.9	12.0	-	145.9	180.5
47	1835	OH Conductors & Devices	4.0%	330.2	11.2	-	341.4	202.9	12.6	-	215.5	125.9
47	1840	UG Conduit	4.0%	970.6	76.7	-	1,047.3	471.4	37.3	-	508.8	538.5
47	1845	UG Conductors & Devices	4.0%	596.0	45.4	-	641.5	303.2	23.5	-	326.7	314.8
47	1850	Line Transformers	4.0%	572.9	35.2	-	608.0	289.9	21.3	-	311.2	296.9
47	1855	Services (OH & UG)	4.0%	43.8	8.6	-	52.5	5.0	1.9	-	6.9	45.6
47	1860	Meters	4.0%	161.1	1.4	24.8	137.7	88.9	8.7	-	97.6	40.2
47	1861	Smart Meters	6.7%	36.0	25.6	-	61.5	-	-	-	-	61.5
47	1861	Smart Meters/Communication Systems	6.7%	-	-	-	-	-	-	-	-	-
N/A	1905	Land	NA	1.9	-	-	1.9	-	-	-	-	1.9
CEC	1906	Land Rights	2.0%	8.7	-	8.7	-	2.0	(1.0)	1.0	0.0	(0.0)
47	1908	Buildings & Fixtures	2.0%	100.7	0.8	-	101.6	32.2	2.5	-	34.7	66.9
13	1910	Leasehold Improvements	20.0%	16.8	1.9	-	18.7	2.9	3.1	-	6.1	12.6
8	1915	Office Furniture & Equipment 10yr	10.0%	22.8	1.2	-	24.0	17.9	0.9	-	18.9	5.1
8	1915	Office Furniture & Equipment 5yr	10.0%	-	-	-	-	-	-	-	-	-
10	1920	Computer - Hardware	20.0%	42.6	6.4	-	48.9	37.2	2.5	-	39.8	9.2
45	1921	Computer - Hardware post Mar 22/04	20.0%	-	-	-	-	-	-	-	-	-
45.1	1921	Computer - Hardware post Mar 19/07	20.0%	-	-	-	-	-	-	-	-	-
12	1925	Computer Software	20.0%	122.5	20.8	-	143.3	89.3	14.5	-	103.8	39.4
10	1930	Transportation Equipment - Automobiles	25.0%	1.7	0.5	0.2	2.0	0.9	0.4	0.1	1.2	0.8
10	1930	Transportation Equipment - Trucks <3 tonnes	20.0%	9.6	0.9	1.2	9.3	7.1	0.9	1.1	6.9	2.4
10	1930	Transportation Equipment - Trucks >3 tonnes	12.5%	41.6	6.0	3.2	44.4	32.4	2.7	3.2	31.9	12.5
10	1930	Transportation Equipment - Work and Service	12.5%	2.4	0.3	0.2	2.5	1.8	0.1	0.2	1.7	0.8
8	1935	Stores Equipment	10.0%	5.5	-	-	5.5	5.5	0.0	-	5.5	0.0
8	1940	Tools, Shop & Garage Equipment	10.0%	30.0	1.3	0.0	31.3	21.0	1.5	-	22.5	8.8
8	1945	Measurement & Testing Equipment	10.0%	4.5	-	(0.0)	4.5	4.0	0.1	-	4.1	0.4
8	1950	Power operated Equipment	12.5%	-	-	-	-	-	-	-	-	-
8	1955	Communications Equipment	20.0%	24.6	4.8	-	29.4	21.7	1.6	-	23.4	6.0
8	1960	Graphics Equipment	10.0%	0.1	-	-	0.1	0.1	-	-	0.1	-
47	1965	Water Heater Rental Units	10.0%	-	-	-	-	-	-	-	-	-

				Cost					**Accumulated Depreciation**				
CCA Class	OEB	Description	Depreciation Rate	Opening Balance	Additions	Disposals and Transfers	Closing Balance		Opening Balance	Additions	Disposals and Transfers	Closing Balance	Net Book Value
47	1970	Load Management Controls	10.0%	14.8	0.0	-	14.8		5.2	1.2	-	6.4	8.5
47	1975	Load Management Controls Utility Premises	10.0%	0.6	-	-	0.6		0.5	0.0	-	0.5	0.0
47	1980	System Supervisor Equipment	6.7%	44.3	6.7	-	51.0		29.4	2.2	-	31.6	19.4
47	1985	Miscellaneous Fixed Assets	10.0%	-	-	-	-		0.0	-	-	0.0	(0.0)
47	1996	Hydro One S/S Contribution		-	-	-	-		-	-	-	-	-
47	1995	Contributions & Grants	4.0%	(201.2)	(23.0)	-	(224.2)		(27.1)	(7.6)	-	(34.7)	(189.5)
10	2005	Property Under Capital Lease	25.0%	0.9			0.9						0.9
		Total		3,523.5	282.8	38.3	3,768.0		1,871.0	149.0	5.7	2,014.3	1,753.7

Note 1: Components may not add up exactly to Total due to rounding.

Note 2: Depreciation for "2005 - Property under Capital Lease" is included in "1930 - transportation Equipment - Automobiles"

Table 2: Bridge 2009

				Cost				Accumulated Depreciation				
CCA Class	OEB	Description	Depreciation Rate	Opening Balance	Additions	Disposals and Transfers	Closing Balance	Opening Balance	Additions	Disposals and Transfers	Closing Balance	Net Book Value
N/A	1805	Land	NA	2.2	-	0.0	2.2	-	-	-	-	2.2
CEC	1806	Land Rights	2.0%	1.7	0.0	1.7	-	0.2	-	0.2	-	-
47	1808	Buildings	2.0%	43.9	2.3	0.1	46.2	15.8	0.9	0.0	16.6	29.6
13	1810	Leasehold Improvements	10.0%	-	-	-	-	-	-	-	-	-
47	1815	Transformer Station Equipment >50 kV	2.5%	11.9	-	-	11.9	3.8	0.3	-	4.1	7.8
47	1820	Substation Equipment	3.3%	181.5	12.8	(0.0)	194.3	77.6	5.4	-	83.0	111.3
47	1825	Storage Battery Equipment	NA	-	-	-	-	-	-	-	-	-
47	1830	Poles, Towers & Fixtures	4.0%	326.5	9.2	(0.0)	335.7	145.9	12.4	-	158.3	177.3
47	1835	OH Conductors & Devices	4.0%	341.4	4.5	0.0	345.9	215.5	12.7	-	228.2	117.7
47	1840	UG Conduit	4.0%	1,047.3	64.3	(0.0)	1,111.6	508.8	39.0	(0.0)	547.7	563.9
47	1845	UG Conductors & Devices	4.0%	641.5	44.7	0.0	686.2	326.7	25.1	-	351.8	334.4
47	1850	Line Transformers	4.0%	608.0	31.4	(0.0)	639.4	311.2	22.1	0.0	333.3	306.2
47	1855	Services (OH & UG)	4.0%	52.5	11.7	-	64.2	6.9	2.3	-	9.2	55.0
47	1860	Meters	4.0%	137.7	0.3	0.0	138.0	97.6	8.7	-	106.3	31.7
47	1861	Smart Meters	6.7%	61.5	26.8	23.8	64.6	-	-	-	-	64.6
47	1861	Smart Meters/Communication Systems	6.7%	-	-	-	-	-	-	-	-	-
N/A	1905	Land	NA	1.9	-	-	1.9	-	-	-	-	1.9
CEC	1906	Land Rights	2.0%	-	-	-	-	0.0	-	-	0.0	(0.0)
47	1908	Buildings & Fixtures	2.0%	101.6	3.0	(0.0)	104.6	34.7	2.1	-	36.8	67.8
13	1910	Leasehold Improvements	20.0%	18.7	0.8	-	19.5	6.1	3.4	-	9.4	10.0
8	1915	Office Furniture & Equipment 10yr	10.0%	24.0	1.7	-	25.6	18.9	1.0	-	19.9	5.8
8	1915	Office Furniture & Equipment 5yr	10.0%	-	-	-	-	-	-	-	-	-
10	1920	Computer - Hardware	20.0%	48.9	5.0	2.9	51.1	39.8	3.5	-	43.3	7.8
45	1921	Computer - Hardware post Mar 22/04	20.0%	-	-	-	-	-	-	-	-	-
45.1	1921	Computer - Hardware post Mar 19/07	20.0%	-	-	-	-	-	-	-	-	-
12	1925	Computer Software	20.0%	143.3	29.6	5.2	167.8	103.8	16.9	0.1	120.7	47.1
10	1930	Transportation Equipment - Automobiles	25.0%	2.0	-	-	2.0	1.2	0.4		1.6	0.4
10	1930	Transportation Equipment - Trucks <3 tonnes	20.0%	9.3	0.4	-	9.8	6.9	0.9		7.8	2.0
10	1930	Transportation Equipment - Trucks >3 tonnes	12.5%	44.4	9.0	-	53.4	31.9	3.0		34.9	18.6
10	1930	Transportation Equipment - Work and Service	12.5%	2.5	-	-	2.5	1.7	0.1		1.9	0.6
8	1935	Stores Equipment	10.0%	5.5	-	-	5.5	5.5	0.0	-	5.5	0.0
8	1940	Tools, Shop & Garage Equipment	10.0%	31.3	1.3	-	32.6	22.5	1.4	-	23.8	8.8
8	1945	Measurement & Testing Equipment	10.0%	4.5	-	-	4.5	4.1	0.1	-	4.2	0.4
8	1950	Power operated Equipment	12.5%	-	-	-	-	-	-	-	-	-
8	1955	Communications Equipment	20.0%	29.4	1.3	-	30.6	23.4	1.8	-	25.2	5.4
8	1960	Graphics Equipment	10.0%	0.1	-	-	0.1	0.1	-	-	0.1	-
47	1965	Water Heater Rental Units	10.0%	-	-	-	-	-	-	-	-	-
47	1970	Load Management Controls	10.0%	14.8	(0.0)	-	14.8	6.4	1.4	-	7.7	7.1

				Cost				Accumulated Depreciation				
CCA Class	OEB	Description	Depreciation Rate	Opening Balance	Additions	Disposals and Transfers	Closing Balance	Opening Balance	Additions	Disposals and Transfers	Closing Balance	Net Book Value
47	1975	Load Management Controls Utility Premises	10.0%	0.6	-	-	0.6	0.5	0.0	-	0.6	-
47	1980	System Supervisor Equipment	6.7%	51.0	2.3	-	53.2	31.6	2.3	-	33.9	19.3
47	1985	Miscellaneous Fixed Assets	10.0%	-	-	-	-	0.0	-	-	0.0	(0.0)
47	1996	Hydro One S/S Contribution		-	-	-	-	-	-	-	-	-
47	1995	Contributions & Grants	4.0%	(224.2)	(27.8)	-	(252.0)	(34.7)	(8.7)	-	(43.4)	(208.6)
10	2005	Property Under Capital Lease	25%	0.9			0.9					0.9
		Total		3,768.0	234.7	33.6	3,969.2	2,014.3	158.4	0.3	2,172.4	1,796.8

Note 1: Components may not add up exactly to Total due to rounding.
Note 2: Depreciation for "2005 - Property under Capital Lease" is included in "1930 - transportation Equipment - Automobiles"

Table 3: Test 2010

				Cost				Accumulated Depreciation				
CCA Class	OEB	Description	Depreciation Rate	Opening Balance	Additions	Disposals and Transfers	Closing Balance	Opening Balance	Additions	Disposals and Transfers	Closing Balance	Net Book Value
N/A	1805	Land	NA	2.2	-	-	2.2	-	-	-	-	2.2
CEC	1806	Land Rights	2.0%	-	-	-	-	-	-	-	-	-
47	1808	Buildings	2.0%	46.2	0.9	-	47.1	16.6	0.9	-	17.5	29.6
13	1810	Leasehold Improvements	10.0%	-	-	-	-	-	-	-	-	-
47	1815	Transformer Station Equipment >50 kV	2.5%	11.9	-	-	11.9	4.1	0.3	-	4.5	7.4
47	1820	Substation Equipment	3.3%	194.3	27.0	-	221.2	83.0	5.9	-	88.9	132.3
47	1825	Storage Battery Equipment	NA	-	-	-	-	-	-	-	-	-
47	1830	Poles, Towers & Fixtures	4.0%	335.7	28.1	0.0	363.7	158.3	12.8	-	171.2	192.6
47	1835	OH Conductors & Devices	4.0%	345.9	16.0	(0.0)	361.9	228.2	12.8	-	241.0	120.9
47	1840	UG Conduit	4.0%	1,111.6	85.3	(0.0)	1,197.0	547.7	42.4	-	590.2	606.8
47	1845	UG Conductors & Devices	4.0%	686.2	77.5	(0.0)	763.7	351.8	27.2	-	379.0	384.7
47	1850	Line Transformers	4.0%	639.4	50.8	(0.0)	690.2	333.3	23.4	-	356.6	333.6
47	1855	Services (OH & UG)	4.0%	64.2	13.9	-	78.1	9.2	2.8	-	12.0	66.0
47	1860	Meters	4.0%	138.0	0.5	-	138.5	106.3	8.9	-	115.2	23.3
47	1861	Smart Meters	6.7%	64.6	24.5	22.8	66.3	-	-	-	-	66.3
47	1861A	Smart Meters/Communication Systems	6.7%	-	-	-	-	-	-	-	-	-
N/A	1905	Land	NA	1.9	-	-	1.9	-	-	-	-	1.9
CEC	1906	Land Rights	2.0%	-	-	-	-	0.0	-	-	0.0	(0.0)
47	1908	Buildings & Fixtures	2.0%	104.6	6.8	0.0	111.4	36.8	1.9	-	38.7	72.7
13	1910	Leasehold Improvements	20.0%	19.5	0.6	-	20.1	9.4	3.5	-	12.9	7.1
8	1915	Office Furniture & Equipment 10yr	10.0%	25.6	1.0	-	26.6	19.9	0.9	-	20.8	5.8
8	1915B	Office Furniture & Equipment 5yr	10.0%	-	-	-	-	-	-	-	-	-
10	1920	Computer - Hardware	20.0%	51.1	6.0	2.1	55.0	43.3	3.7	-	47.0	7.9
45	1921	Computer - Hardware post Mar 22/04	20.0%	-	-	-	-	-	-	-	-	-
45.1	1921	Computer - Hardware post Mar 19/07	20.0%	-	-	-	-	-	-	-	-	-
12	1925	Computer Software	20.0%	167.8	23.7	0.0	191.4	120.7	16.6	-	137.3	54.2
10	1930A	Transportation Equipment - Automobiles	25.0%	2.0	-	-	2.0	1.6	0.2	-	1.8	0.2
10	1930B	Transportation Equipment - Trucks <3 tonnes	20.0%	9.8	1.8	-	11.6	7.8	0.9	-	8.7	2.9
10	1930C	Transportation Equipment - Trucks >3 tonnes	12.5%	53.4	8.8	-	62.2	34.9	4.0	-	38.9	23.3
10	1930D	Transportation Equipment - Work and Service	12.5%	2.5	-	-	2.5	1.9	0.1	-	2.0	0.5
8	1935	Stores Equipment	10.0%	5.5	-	-	5.5	5.5	0.0	-	5.5	0.0
8	1940	Tools, Shop & Garage Equipment	10.0%	32.6	1.6	-	34.3	23.8	1.4	-	25.3	9.0
8	1945	Measurement & Testing Equipment	10.0%	4.5	-	-	4.5	4.2	0.1	-	4.3	0.3
8	1950	Power operated Equipment	12.5%	-	-	-	-	-	-	-	-	-
8	1955	Communications Equipment	20.0%	30.6	0.3	-	31.0	25.2	1.9	-	27.1	3.8
8	1960	Graphics Equipment	10.0%	0.1	-	-	0.1	0.1	-	-	0.1	-
47	1965	Water Heater Rental Units	10.0%	-	-	-	-	-	-	-	-	-
47	1970	Load Management Controls	10.0%	14.8	-	-	14.8	7.7	1.3	-	9.1	5.8

CCA Class	OEB	Description	Cost: Depreciation Rate	Cost: Opening Balance	Cost: Additions	Cost: Disposals and Transfers	Cost: Closing Balance	Accumulated Depreciation: Opening Balance	Accumulated Depreciation: Additions	Accumulated Depreciation: Disposals and Transfers	Accumulated Depreciation: Closing Balance	Net Book Value
47	1975	Load Management Controls Utility Premises	10.0%	0.6	-	-	0.6	0.6	-	-	0.6	-
47	1980	System Supervisor Equipment	6.7%	53.2	11.7	-	64.9	33.9	2.5	-	36.5	28.5
47	1985	Miscellaneous Fixed Assets	10.0%	-	-	-	-	0.0	-	-	0.0	(0.0)
47	1996	Hydro One S/S Contribution		-	-	-	-	-	-	-	-	-
47	1995	Contributions & Grants	4.0%	(252.0)	(17.9)	0.0	(269.9)	(43.4)	(9.7)	-	(53.1)	(216.8)
10	2005	Property Under Capital Lease	25%	0.9			0.9				-	0.9
		Total		3,969.2	368.8	24.8	4,313.1	2,172.4	167.0	-	2,339.4	1,973.7

Note 1: Components may not add up exactly to Total due to rounding.
Note 2: Depreciation for "2005 - Property under Capital Lease" is included in "1930 - transportation Equipment - Automobiles"

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INTERROGATORY 55:

Reference(s): D1/ T1/ S1

In the first of these references, THESL provides amounts for "Externally Initiated Plant Relocations" of 0 for 2008 Historical and 2009 Bridge and $27.8 million for the 2010 Test year.

In the second of these references, THESL provides in Table 1 "Externally Initiated Plant Relocation Summary," line item amounts for "Externally Initiated Plant Relocation – Gross" of $18.0 million in 2008 Historical, $6.9 million in 2009 Bridge and $27.8 million for the 2010 Test year.

Please provide an explanation for the differences in the 2008 Historical and 2009 Bridge amounts between these two references.

If Table 2 "Summary of Capital Budget" of the first reference needs to be adjusted for this differential, please provide a revised version of this table containing any other necessary adjustments.

RESPONSE:

In Exhibit D1, Tab 9, Schedule 5, below Table 1, it is noted that the 2008 Historical and 2009 Bridge Gross amounts are captured in the sustaining capital programs and are not shown separately in the summary table in Exhibit D1, Tab 7, Schedule 1.

Starting in 2010 THESL decided to identify these externally initiated plant relocation projects separately from other programs due to the large number of anticipated requests

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from external agencies (particularly due to various levels of Governments stimulus packages).

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INTERROGATORY 56:

Reference(s): D1/T7/S1/p.20
D1/T8/S10/p.43

In the first of these references, THESL's "Total Capital" for the 2010 Test year is shown as $423.6 million.

In the second of these references, the "Total Capital Plan" amount for 2010 is shown as $366.9 million.

Please provide an explanation for the differences between these two numbers and if either one of these tables require changes, please provide revised versions of them.

RESPONSE:

The summary of Capital Budget as shown on page 19 of 20 in Exhibit D1, Tab 7, Schedule 1 is correct. Line item labelled "Total Sustaining Capital" with $157.0 M is common and identical to both documents. Line items labelled "Reactive Work" with $22.5M, "Customer Connections" with $32.5M, and "Customer Capital Contribution" with ($24.4M) are common and identical to both documents.

Line item "Asset Management"' with $2.8M in Exhibit D1, Tab 7, Schedule 1 has been included in the Stations System Enhancement Exhibit D1, Tab 8, Schedule 10.

Line item "Engineering Capital" with $31.2M in Exhibit D1, Tab 7, Schedule 1 does not correspond to the line item "Engineering Capital" with $30.1M in Exhibit D1, Tab 8, Schedule 10. Engineering Capital is a function of Total Capital and the $30.1M

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represents a number derived from a previous iteration of a smaller capital. The Line Item "Engineering Capital" with $31.2M Exhibit D1, Tab 7, Schedule 1 will remain as is and the line item "Engineering Capital" with $30.1M in Exhibit D1, Tab 8, Schedule 10 will be revised to $31.2M.

Line item "AFUDC" with $4.4Min Exhibit D1, Tab 7, Schedule 1 (Allowance for Funds Used During Construction) was not considered in the 2010-2019 Electrical Distribution Capital as it is a financial concept that does not need to be considered for Capital Construction Projects. All line items within General Plant, Customer Services and Information Technology in Exhibit D1, Tab 7, Schedule 1 (Total of $75.6M), are not captured in the 2010-2019 Electrical Distribution Capital Plan in Exhibit D1, Tab 8, Schedule 10.

Line items "Standardization", "Downtown Contigency", "FESI 7 / WPF", "Smart Grid Operations", "Externally Initiated Plant Relocations", and "Secondary Upgrade" are common and identical in both documents.

Line item "Stations System Enhancements" with $15.2M in Exhibit D1, Tab 7, Schedule 1 is short by $2.8M as explained earlier and once considered does equate to the $18.0M as shown in line item "Stations System Enhancements" in Exhibit D1, Tab 8, Schedule 10.

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INTERROGATORY 57:

Reference(s): D1/T7/S1

Please provide a summary for the past five historical years, the bridge year and the test year, showing capital expenditures, treatment of contributed capital and additions and deductions from CWIP.

RESPONSE:

Please see Appendix A and B of this Schedule.

Note, of the five-year historical data, the former years (2004-2007) are not available in the requested format.

Summary of Capital Budget ($ millions)

	2004 Actual	2005 Actual	2006 Actual	2007 Actual	2008 Actual	2009 Bridge	2010 Test
Operational Investments							
Sustaining Capital							
Underground Direct Buried	0.9	2.7	7.3	33.0	23.8	48.3	70.3
Underground Rehabilitation	17.0	30.6	33.1	35.7	38.2	33.7	36.3
Overhead	24.4	28.3	19.0	24.3	19.3	15.7	22.0
Network	5.6	6.4	5.6	9.9	4.7	4.8	5.7
Transformer Stations	2.5	1.6	0.8	15.9	8.5	7.2	15.9
Municipal Substation Investment	2.3	4.7	6.0	6.2	8.3	6.3	6.8
Total Sustaining Capital	**52.8**	**74.2**	**71.8**	**125.0**	**102.9**	**116.0**	**157.0**
Reactive Work	6.6	8.2	11.1	15.6	19.3	13.8	22.5
Customer Connections	30.7	35.1	36.4	41.7	42.8	37.4	32.5
Customer Capital Contributions	- 24.7	- 29.2	- 23.6	- 27.0	- 32.7	- 21.0	- 24.4
Asset Management	3.8	0.7	2.6	0.3	- 4.9	1.0	2.8
Engineering Capital	12.4	15.2	21.0	20.7	26.4	27.0	31.2
AFUDC	-	-	-	3.4	2.0	2.6	4.4
Other	-	-	-	1.3	1.0	1.0	-
Total Operations	**81.7**	**104.1**	**119.3**	**181.0**	**156.8**	**177.8**	**226.0**
General Plant							
Fleet & Equipment Services	3.1	4.8	6.2	9.2	7.9	9.9	11.4
Facilities	1.9	2.7	5.7	20.0	3.4	8.4	12.6
Other (includes tools)	1.5	5.2	5.9	4.2	0.3	2.0	4.4
Total General Plant	**6.6**	**12.7**	**17.8**	**33.3**	**11.6**	**20.3**	**28.4**
Customer Services							
Wholesale Metering			1.5		-	0.5	10.9
Suite Metering			-		-	1.8	2.4
Other	6.3	7.4	3.6	4.6	13.2	0.2	0.6
Total Customer Services	**6.3**	**7.4**	**5.1**	**4.6**	**13.2**	**2.5**	**13.9**
Total Information Technology	**5.2**	**8.1**	**15.2**	**20.4**	**24.1**	**27.8**	**33.3**
Total Operational Investments	**99.7**	**132.3**	**157.4**	**239.3**	**205.7**	**228.4**	**301.6**
Emerging Requirements							
Standardization	-	-	-	-	-	5.5	32.7
Downtown Contingency	-	-	-	-	-	-	31.3
FESI 7 / WPF	-	-	-	-	-	1.6	5.5
Smart Grid Operations	-	-	-	-	-	-	3.0
Externally Initiated Plant Relocations	-	-	-	-	-	-	27.8
Stations System Enhancements	-	-	-	-	-	-	15.2
Secondary Upgrade	-	-	-	-	-	-	6.5
Total Emerging Requirements	**-**	**-**	**-**	**-**	**-**	**7.1**	**122.0**
TOTAL CAPITAL	**99.7**	**132.3**	**157.4**	**239.3**	**205.7**	**235.5**	**423.6**
SM				39.0			
CDM (net of recoveries)				1.2			
SM Reclass F/S adjustment				- 3.9			
Capital Spend as per F/S				**275.6**			

Additions and Deductions from CWIP by Asset Class ($ millions)

	FY08 Actual Jan CWIP Open Balance	FY08 Actual Dec Cum CWIP Additions	FY08 Actual Dec Cum CWIP Transfer to Asset	FY08 Actual Dec CWIP Closing Balance
Land_and_Buildings	1.2	1.0	2.1	0.0
TS_Primary Above 50	-	0.4	-	0.4
Distribution Stn Equip	18.5	21.8	34.2	6.0
Poles_Wires	63.2	126.0	147.1	42.1
Line_Transformers	9.0	31.0	35.2	4.8
Services_and_Meters	1.6	37.8	35.6	3.8
Asset - General Plant	2.5	1.8	2.7	1.7
Equipmnt	11.6	10.5	14.9	7.2
IT_Assets	20.5	29.9	27.2	23.2
CDM_Expenditures and Recoveries	-	-	-	-
Other_Distribution Assets	4.5	2.6	6.7	0.4
Contributions and Grants - Credits	(8.9)	(30.6)	(23.0)	(16.5)
Non_Distribution Asset	-	-	-	-
Non_Asset	6.5	2.1	-	8.5
	130.1	234.3	282.8	81.7
Net Expenditures	-	-	(48.4)	105.9

	FY09 Bridge Jan CWIP Open Balance	**FY09 Bridge Dec Cum CWIP Additions**	**FY09 Bridge Dec Cum CWIP Transfer to Asset**	**FY09 Bridge Dec CWIP Closing Balance**
Land_and_Buildings	0.0	2.9	2.4	0.5
TS_Primary Above 50	0.4	1.0	-	1.4
Distribution Stn Equip	6.0	15.6	12.8	8.8
Poles_Wires	42.1	138.5	122.8	57.8
Line_Transformers	4.8	35.4	31.4	8.9
Services_and_Meters	3.8	38.2	38.8	3.2
Asset - General Plant	1.7	3.9	3.8	1.8
Equipmnt	7.2	14.0	13.7	7.5
IT_Assets	23.2	30.4	34.6	19.0
CDM_Expenditures and Recoveries	-	-	-	-
Other_Distribution Assets	0.4	2.8	2.3	0.9
Contributions and Grants - Credits	(16.5)	(21.0)	(27.8)	(9.7)
Non_Distribution Asset	-	-	-	-
Non_Asset	8.5	-	-	8.5
	81.7	261.7	234.7	108.6
Net Expenditures	-	-	26.9	95.1

	FY10 TEST Jan CWIP Open Balance	**FY10 TEST Dec Cum CWIP Additions**	**FY10 TEST Dec Cum CWIP Transfer to Asset**	**FY10 TEST Dec CWIP Closing Balance**
Land_and_Buildings	0.5	8.7	0.9	8.4
TS_Primary Above 50	1.4	10.7	-	12.1
Distribution Stn Equip	8.8	36.2	27.0	18.0
Poles_Wires	57.8	236.8	206.9	87.7
Line_Transformers	8.9	51.4	50.8	9.5
Services_and_Meters	3.2	41.9	38.9	6.3
Asset - General Plant	1.8	13.0	7.4	7.4
Equipmnt	7.5	13.2	13.5	7.2
IT_Assets	19.0	35.7	29.6	25.0
CDM_Expenditures and Recoveries	-	-	-	-
Other_Distribution Assets	0.9	15.9	11.7	5.1
Contributions and Grants - Credits	(9.7)	(15.4)	(17.9)	(7.3)
Non_Distribution Asset	-	-	-	-
Non_Asset	8.5	-	-	8.5
	108.6	448.2	368.8	187.9
Net Expenditures	-	-	79.4	148.3

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INTERROGATORY 58:

Reference(s): D1/T7/S1

Please provide a Capital Projects Table as shown in Appendix 2-B of Chapter 2 of the Filing Requirements for Transmission and Distribution Applications, issued May 27, 2009.

RESPONSE:

THESL has an extensive capital program with hundreds of individual projects, each of which impacts a number of USoA accounts. THESL's finance system translates the operational categories used by the business units into USoA accounts but the costs are aggregated. The one-to-one relationship between a project and the affected USoA account is not preserved and it would be an enormous undertaking to reproduce the costs in the format of Appendix 2-B in the Board's Filing Requirements.

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INTERROGATORY 59:

Reference(s): D1/T7/S1

THESL states that it has evolved from a reactive capital investment planning process to a more proactive planning process.

a) Please provide a separate table that lists proactive capital expenditure projects only.

b) Please identify what percentage of capital expenditure projects are considered reactive and what percentage are considered proactive.

RESPONSE:

a) All sustaining capital and emerging projects are proactive capital expenditure projects. The table which list the proactive capital expenditure projects ($500K and over) are shown in the EB-2009-0139, Exhibit D1, Tab 8, Schedules 9-1 to 9-8.

b) Proactive Capital Expenditure:
   1) Sustaining Capital Total: $157M
   2) Emerging Capital Total: $124.8M

   Total Proactive Capital Expenditure: $281.8M

   Reactive Capital Expenditure: $22.5M

   Proactive Percentage: $281.M / $423.6M = 66.5%

   Reactive Percentage: $22.5M / $423.6M = 5.3%

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Proactive and Reactive Capital Expenditures are obtained from EB-2009-0139, Exhibit D1, Tab 8, Schedule 10, Table 1 – Ten-year Plan Summary, page 6.

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INTERROGATORY 60:

Reference(s): **D1/ T8/ S1**
D1/ T8/ S10

On page 9 of the 2010-2019 Electrical Distribution Capital Plan (the second reference), THESL states for proposing sustaining capital investments, "the condition of key asset classes such as direct buried underground cable is one of the strongest drivers for the forecasted size of the sustaining capital investments"

THESL further states that while in almost all cases, a "like-for-like" strategy has been adopted for the purpose of forecasting capital requirements, the principal exception to this strategy is that of underground direct buried cable that is replaced with underground cable in conduit.

On pages 13 and 14 of the first reference [D1/T8/S1], THESL discusses alternatives for extending the life of in-service cables and finding cost effective installation techniques for cable replacement. THESL states that based on its own direct experience from its pilot project (Braymore Boulevard East and West) and observations of other utilities: "the conclusion is that cable rejuvenation process is unable to remediate cable sections that have developed electrical trees and therefore pose a risk in the process of extending the useful life of the cables."

a) Please provide the percentage of population of underground buried cable that have developed electrical trees.
b) Please indicate the level of completion of the two pilot projects currently conducted by THESL; and provide details of the outcome of these pilot projects to date.
c) Please state the method of silicon injection that has been used in these pilot projects.

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d) Please provide a description of THESL's ongoing efforts to find improved alternative solutions to rehabilitate its high risk cables. Please describe what steps are being taken to prevent moderate risk cables from developing electrical trees.

e) Please provide details as to the observations of other utilities referenced on line 27 of page 13.

RESPONSE:

a) THESL approximates that between 30 to 75 percent of its XLPE cable has a high probability of having electrical trees. These findings are based on the following studies:
   - Asset condition assessment results, using failure history and age of cable insulation – 75 percent of cable is considered to be very poor and poor.
   - Cable partial discharge testing was conducted on 0.4 percent sample size where almost 30 percent of the cable tested had partial discharge which may indicate formation of electrical trees. However, some of the cable deemed clear of partial discharge failed a short time later due to an electrical tree.

b) Novinium (Cable Injection Contractor) injected 8,137 of the planned 9,213 metres of cable in the Braymore West pilot project in August 2008. Since injection, THESL has experienced three cable failures.

Transelec (Cable Injection Contractor) injected 6,658 metres of the planned 9,014 metres of cable in the Braymore East pilot project (2,427 in November 2008 and 4,231 in September 2009). Since injection, there have been no failures.

There were many planned outages, some exceeding the six to eight hours considered

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tolerable by customers. Additional planned outages were needed to include additional splice locations. Furthermore, the cable injection process cannot be applied to single conductor and strand blocked cable. The strand blocked cable was introduced as a standard in most of the GTA utilities in early 1990s.

c) Novinium uses a sustained pressure injection process that requires the cable be de-energized during the injection process. The fluid is continually injected at one end until it flows through the other end of the cable. The time taken to inject is exponential to the length of the cable. For a typical compact cable section (19-strand cable) of 200 metres it takes approximately 9 hours to inject.

While with Transelec, CableCURE fluid is injected into the cable through an injection elbow. Depending on conductor size and length, fluid will take 30 minutes to 30 hours to flow through the cable. The cable may be energized during injection.

Both methodologies require prior replacement of all existing cable splices on the cable that is to be injected.

d) THESL's approach in rehabilitating high and moderate risk cable is to replace these cables based on evaluation of condition and risk associated. These are then prioritized to obtain an optimal annual portfolio spending.

Over the last two years THESL has spent considerable effort in exploring alternative solutions to find and rehabilitate moderate and high risk cables. So far the conclusions are that the accuracy of finding the highest risk cables is low, rehabilitation methods are complex, disruptive to customers and after completion,

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failures have continued to occur. THESL will continue to explore further alternative solutions and testing methodologies.

e) In evaluating the pilot projects THESL reviewed similar projects carried out by BC Hydro, Manitoba Hydro, ENMAX, City of Saskatchewan, Hydro One Brampton and PowerStream. It was generally noted that there is no certainty in predicting the location of electrical trees in the underground direct buried cable. However, most utilities tend to use cable failures and age of cable as a proxy to determine the high risk cable.

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INTERROGATORY 61:

Reference(s): **D1/ T8/ S1**

Please provide an itemized breakdown of network capital expenditures for the past five historical years, the bridge year and the test year.

RESPONSE:

The following is a breakdown of capital expenditures for the network system:

Network Units	2004	2005	2006	2007	2008	2009	2010
	Units						
Number of Network Units Changed Out	50	61	56	53	50	50	50
	Per Unit Capital Spending ($,000s)						
	83.3	89.1	85.0	87.8	90.8	94.1	97.5

Note: Total average cost per change out, including design, switching, materials, contracts and construction labour costs are included in the Per Unit Capital Spending in the above table. These costs are average cost to change out each network unit. Network unit consist of a Transformer, Protector and Primary Switch.

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INTERROGATORY 62:

Reference(s): **D1/ T8/ S1**

Please provide an itemized breakdown of capital expenditures for overhead systems for the past five historical years, the bridge year and the test year.

RESPONSE:

The following is a breakdown of capital expenditures for overhead systems:

Overhead Components	2004	2005	2006	2007	2008	2009	2010
	Units						
Poles	843	976	963	847	1234	1177	1403
Polemount Transformers	686	1020	875	898	717	441	527
Switches - Remote	26	22	35	42	48	26	155
	Total Capital Spending ($M)						
Total Capital Spending ($M)	24.4	28.3	19.0	24.3	19.3	15.7	22.0

Note: Due to general embedded costs captured in the work orders (such as switching), the capital expenditures for the individual overhead components is not provided. This task would take considerable time. Furthermore, the general costs may not be accurately apportioned to each overhead component.

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INTERROGATORY 63:

Reference(s): D1/ T8/ S1

A description of capital expenditures for Transformer Stations is found in this exhibit. On page 28, THESL proposes a $7.4 million or 87% increase in capital investment for transformer stations over 2008 Historical:

a) Please provide an itemized breakdown of transformer station capital investments for the past five historical years, the bridge year and the test year.

b) Please provide a percentage of the population for each component of transformer station investment.

RESPONSE:

a) Table 1 is an itemized breakdown of transformer station capital investments, as described in Exhibit D1 Tab 8 Schedule 1 pages 25-28 for the past five historical years, the bridge year and the test year.

Table 1: Transformer Station Capital Investments 2004-2010 ($millions)

	2004 Historical	2005 Historical	2006 Historical	2007 Historical	2008 Historical	2009 Bridge	2010 Test
Switchgear	0.6	0.3	0.1	12.1	7.5	6.5	14.3
Circuit Breakers	0.1	0.2	0.9	0.7	0.4	0.4	1.0
RTU (SCADA)	0.1	0.4	0.3	0.8	0.3	0	0
Miscellaneous[1]	0.4	0.9	0.4	0.2	0.6	0.3	0.6
Total	1.2	1.9	1.7	13.8	8.8	7.2	15.9

[1]Includes assets such as station service transformers, and investments such as feeder position preparation, civil costs and other individual investments less than $100,000.

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b) Table 2 is a presentation of the unit counts and the percentage of the population of each component due to investments indicated in Table 1. The top number is the number of units and the number beneath is a percentage of the population.

Table 2: Percentage of Population for Each Investment

	Population	2004 Historical	2005 Historical	2006 Historical	2007 Historical	2008 Historical	2009 Bridge	2010 Test
Switchgear[1]	52 100%	0	0	0	3 5.8%	2 3.8%	1 1.9%	3 5.8%
Circuit Breakers	737 100%	0	2 0.3%	17 2.3%	16 2.2%	4 0.5%	2 0.3%	6 0.8%
RTU (SCADA)	56 100%	1 1.8%	3 5.4%	1 1.8%	3 5.4%	1 1.8%	0	0

[1] A 13.8kV indoor metal-clad switchgear replacement will include 14 to 16 circuit breakers.

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INTERROGATORY 64:

Reference(s): D1/ T8/ S6-1
C2/ T2/ S5

On page 2 of the first reference, THESL states that the increase to total Fleet and Equipment Services of $2.0 million in the 2009 bridge year is attributed to the addition of 15 new vehicles to the overall fleet, which are required to support the additional hiring of Trades and Technical staff. Exhibit C2/T1/S5, Table 4 shows a decrease of total headcount for Trades and Technical staff from 88 in 2008 to 71 in 2009.

a) Please explain the previous statement in light of the decrease in Trades and Technical staff in the 2009 Bridge year
b) Please provide a list of the vehicles purchased.
c) THESL stated on page 2 of the first reference that the fleet and equipment replacement program is based on a five-year cycle of capital investment. Please explain why THESL has chosen to purchase the 15 new vehicles ahead of the increase in headcount expected for the 2010 test year.
d) Please explain the increase in "Total Fleet and Equipment Services" in the 2010 Test year shown in Table 1 of the first reference.

RESPONSE:

a) Additional vehicles were purchased in 2009 to support 17 additional Apprentices and additional Technical staff (including additional Supervisors) required to support the capital work plan. The number of Apprentices in the program (Exhibit C2, Tab 1, Schedule 5, page 8) is not directly related to vehicle requirements.

b) Please see Appendix A of this Schedule.

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c) The purchase of 15 new vehicles in 2009 is not related to the expected 2010 increase in head count. The purchase of the 2009 vehicles was to support capital work and additional staff hired in 2009, and the displacement of some rental vehicles.

d) The increase in the 2010 Test year is primarily due to:
   (1) Replacement of old vehicles according to the replacement schedule;
   (2) Green Premiums associated with purchases in line with "Greening of the Fleet"to reduce GHG emissions; and
   (3) New requirements to support the increase in capital work and staff (Apprentices, Trades & Technical – including Supervisors).

FLEET TABLE 1: 2009 Purchased Vehicles

Units	New Vehicle Number	Vehicle Type
1	0422V	PickUp
2	0423V	PickUp
3	0171V	HSUV
4	0172V	HSUV
5	0173V	HSUV
6	0174V	HSUV
7	0175V	HSUV
8	0176V	HSUV
9	0177V	HSUV
10	0170V	HSUV
11	0854V	JointerCubeVan
12	0855V	JointerCubeVan
13	0902V	Sprinter CubeVan
14	0990V	DoubleBucket
15	1285V/1286V	MiniDerrick&Trailer

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INTERROGATORY 65:

Reference(s): D1/ T8/ S6-2

Table 1 provides Facilities capital for the years 2008 Historical, 2009 Bridge and 2010 Test. Please expand this table to include the historical years 2004 to 2007 and a breakdown of facilities capital into its key components.

RESPONSE:

	2004 Historical	2005 Historical	2006 Historical	2007 Historical	2008 Historical	2009 Forecast	2010 Test Forecast
Administrative offices and operations centres			1.5	1.8	2.0	5.2	10.5
Substations			1.2	1.5	0.6	1.5	1.1
Office Furniture			1.1	2.4	1.1	1.7	0.8
Environmental	-	-	-	-	-	-	0.2
Facility Baseline	**2.0**	**2.8**	**3.8**	**5.7**	**3.7**	**8.4**	**12.6**
Facility Strategy	0.0	0.0	1.8	8.0	0.0	0.0	0.0

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INTERROGATORY 66:

Reference(s): C2/ T2/ S2

Please provide an itemized breakdown for the category "other general" in each of tables 2, 3 and 4.

RESPONSE:

Table 2: Other – Details

14 CARLTON ST - CONSTRUCT EOC ROOM	103,239
14 CARLTON ST - REFURBISH FRONT DOORS	123,239
14 CARLTON ST - REPLACE (6) EXHAUST FANS	27,895
14 CARLTON ST - REPLACE FLOOR DRAINS	13,447
14 CARLTON ST - SUPP/INSTAL P.A. RECEIVER	15,000
14 CARLTON ST - UPGRADE BUILD'G AUTOMATION CONTROL	21,289
14 CARLTON ST - REPLACE A/C IN PHONE RM	16,533
14 CARLTON ST - REPLACE A/C IN ELECTRICAL RM	7,724

Table 3: Other – Details

5800 YONGE ST - REPLACE HALON SYSTEM	120,303
5800 YONGE ST - REBUILD FIRST AID ROOM	38,707
5800 YONGE ST - REBUILD RAMP	47,943

Table 4: Other – Details

500 COMMISSIONERS ST - CONSTRUCT STORM ROOM	153,239
500 COMMISSIONERS ST - REPLACE PROPANE DETECTION SYSTEM	8,572
500 COMMISSIONERS ST - INSTALL NEW CCTV SYSTEM	142,430
500 COMMISSIONERS ST - INSTALL BIRD SPIKE IN FLEET PARK'G	30,000

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INTERROGATORY 67:

Reference(s): D1/ T7/ S1

On page 19, Summary of Capital Budget under the category 'General Plant' THESL shows a 120% increase in the test year over the 2009 bridge year and 1366% increase over 2008 Actual.

Please provide an itemized breakdown of this category for each of these years.

RESPONSE:

This interrogatory mis-states THESL's evidence. The evidence in Exhibit D1, Tab 7, Schedule 1, page 19, Table 2 shows 40% increase in the test year over the 2009 bridge year, and 145% increase over 2008 actual for General Plant.

The itemized breakdown for this category is provided in the same table.

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INTERROGATORY 68:

Reference(s): Exhibit D1/ Tab 7/ Schedule 1

THESL stated that "The majority of the work at the wholesale metering installations is contracted to HONI because the equipment is located within HONI facilities. The fluctuations in the capital spend from 2008 to 2009 and 2010 are due to HONI's schedule to complete the installations, and the timing of requests for these installations made by THESL".

a) Please provide further explanation as to how wholesale metering projects are planned, scheduled and executed.
b) Please provide the percentage of wholesale metering installation that is contracted to HONI and the percentage that is conducted by THESL.
c) Please provide a listing by project including the start and end date for each project.
d) Please provide capital expenditures for wholesale metering for the past five historic years, the 2009 bridge year and the 2010 test year.

RESPONSE:

a) Wholesale metering projects are planned to coordinate with THESL's Switchgear Replacement Plan (a station asset renewal program), Measurement Canada regulated replacements, and Hydro One ongoing maintenance requirements.

   Wholesale metering projects are scheduled based on the following sequence:

   - Toronto Hydro submits a "Schedule 1" Form requesting work to be done by Hydro One.
   - Hydro One confirms acceptance and schedules a site visit base on availability of resources.

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- Once the site visit is complete, Hydro One develops a technical proposal with standard costs. This proposal is received by Toronto Hydro three-to-six months after the site visit. If the proposal is acceptable, THESL provides a purchase order for the quoted cost.
- The wholesale meter installations that are done in conjunction with THESL's Switchgear Replacement Plan are scheduled in conjunction the switchgear installation.

Wholesale metering projects that are executed by Hydro One engineering and construction forces, are normally completed within 18-months of THESL providing a purchase order, subject to the availability of Hydro One resources. The portions of the work performed by THESL are completed within the same 18-month period. Testing and commissioning functions are performed in conjunction with IESO staff, to ensure the installation meets IESO requirements. The wholesale meter installations that are done in conjunction with THESL's Switchgear Replacement Plan are installed as part of the switchgear installation.

b) The percentage of the wholesale metering installation that is contracted to HONI has ranged from 56 to 79 percent. The percentage that is conducted by THESL has ranged from 21 to 44 percent.

c) The following are the start and end dates of wholesale meter upgrade projects:

Station	Number of Meter Points	Start Date (Schedule 1)	Completed
Manby TS	1	2004	2004
John TS	3	2004	2005
Wiltshire TS	2	2004	2006
Rexdale TS	2	2005	2006

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Station	Number of Meter Points	Start Date (Schedule 1)	Completed
Finch TS	4	2005	2006
Manby TS	2	2006	2006
Woodbridge TS	2	2005	2007
Fairchild TS	4	2006	2007
Cavanagh TS	4	2006	2007
Leslie TS	3	2006	2007
Bathurst TS	4	2006	2007
Richview TS	3	2006	2007
Manby TS	1	Jun-2007	Nov-2008
Agincourt TS	4	Sep-2006	May-2008
Richview TS	4	Sep-2006	Nov-2008
Fairchild TS	8	Sep-2006	Nov-2008
Leslie TS	4	Sep-2006	Jul-2008
Malvern TS	4	May-2007	Oct-2008
Glengrove TS	2	2006*	Jun-2009
Carlaw TS	1	2006*	Dec-2009
Terauley TS	1	2006*	Oct-2009
Carlaw TS	1	2008*	2010
Terauley TS	1	2008*	2010
Sheppard TS	4	Aug-2006	Nov-2010
Rexdale TS	4	May-2007	Dec-2010
Leslie TS	4	May-2007	Feb-2011
Richview TS	6	May-2007	Apr-2011
Horner TS	4	May-2007	May-2011
Bathurst TS	8	May-2007	Jun-2011
Finch TS	8	May-2007	Sep-2011
Carlaw TS	2	2009*	2011
Glengrove TS	2	2009*	2011
Strachan TS	2	2009*	2011

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Station	Number of Meter Points	Start Date (Schedule 1)	Completed
Wiltshire TS	2	2009*	2011
Scarborough TS	8	Aug-2009	2012
Basin TS	4	Aug-2009	2012
Bridgeman TS	2	Aug-2009	2012
Gerrard TS	6	Aug-2009	2012
John TS	8	Aug-2009	2012
Strachan TS	2	2009*	2012
Wiltshire TS	2	2009*	2012
Duplex TS	2	2009*	2013
Warden TS	4	Aug-2009	2013
Dufferin TS	4	Aug-2009	2013
Esplanade TS	6	Aug-2009	2013
Fairbank TS	4	Aug-2009	2013
Leaside TS	8	Aug-2009	2013
Main TS	2	Aug-2009	2013
Strachan TS	2	Aug-2009	2013
Ellesmere TS	4	Aug-2009	2014
Bermondsey TS	6	Aug-2009	2014
Runnymede TS	2	Aug-2009	2014
Terauley TS	2	Aug-2009	2014
Manby TS	2	Aug-2009	2014
Bridgman TS	2	2012*	2014
Duplex TS	2	2012*	2014
Strachan TS	2	2012*	2014
Wiltshire TS	2	2012*	2014
Duplex TS	2	2013*	2015
Main TS	2	2013*	2015
Dufferin TS	2	2014*	2016
John TS	4	2014*	2016

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Station	Number of Meter Points	Start Date (Schedule 1)	Completed
John TS	2	2014*	2016
Terauley TS	2	2014*	2016
Dufferin TS	2	2015*	2017
Cecil TS	2	2015*	2017
John TS	2	2015*	2017
Bridgman TS	3	2016*	2018
Terauley TS	2	2016*	2018
Cecil TS	2	2017*	2019
Bridgman TS	3	2017*	2019
Charles TS	2	2017*	2019
Cecil TS	2	2018*	2020
Charles TS	2	2018*	2020
Charles TS	2	2019*	2021
Charles TS	2	2020*	2022

*These installations will not have a Schedule 1 -- metering replaced in conjunction with THESL's Switchgear Replacement Plan.

Note: Completion dates beyond 2011 have not yet been committed by Hydro One or THESL.

d) The wholesale metering costs requested are as follows:

2004: $0.8 million
2005: $0.3 million
2006: $0.8 million
2007: $0.5 million
2008: $4.4 million
2009: $0.1 million
2010: $6.9 million

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INTERROGATORY 69:

Reference(s): **D1/ T8/ S7**
D1/ T7/ S1

On page 19 [D1/ T7/ S1], Summary of Capital Budget, under the category ‘Other’ in the Customer services (Metering) section, THESL lists $0.6 million for the 2010 test year.

On page 3 [D1/ T8/ S7] under the section ‘Other Metering Capital’ THESL states that: “Since these accounts already have interval meters, which by definition are considered to be Smart Meters, this project is not considered to be part of the Smart Meter initiative. The budgeted cost for this work is $0.4 million.”

a) Please reconcile the $0.6 million with the $0.4 million.
b) Please elaborate further on THESL’s view that these meters should not be considered as part of the Smart Meter initiative.

RESPONSE:

a) On page 19 of D1/ T7/ S, Summary of Capital Budget, under the category “Other” in the Customer Services (Metering) section, the $0.6 million includes the $0.4 million shown on page 3 of D1/ T8/ S7 under the section “Other Metering Capital”, plus $0.2 million for Call Centre Interactive Voice Response Call Flow upgrades and First Call Resolution software upgrades that are part of Customer Services capital costs.

b) These meters are installed at large customers (over 200 kW), and have been interval meters (smart meters) for many years before the Smart Meter Initiative was introduced. Whenever replacement was required, the cost of these meters has been charged to the metering capital account. THESL’s understanding is that the Smart

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Meter Initiative was intended to replace old mechanical meters, not to replace existing interval meters (Smart Meters).

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INTERROGATORY 70:

Reference(s): D1/T8/Sh7/p.3

It is stated when discussing suite metering capital expenditure amounts included for 2010 that "In consideration of anticipated requests for THESL to provide such services in both new and existing condominium buildings, the forecasted capital spend is $2.4 million in 2010 for a total of 5,400 suite meter installations."

Please state whether the meters to be installed are smart meters and, if so, why this amount should be included in capital expenditures and not recovered through the smart meter funding adder.

RESPONSE:

The suite meters installed are Smart Meters.

THESL's Smart Meter Implementation Plan was designed to convert existing mechanical meters to Smart Meters. The suite meter initiative converts multi-unit buildings from a single bulk meter to many individual suite meters.

The regulation requiring the installation of Smart Meters in condominium buildings did not come into force until December 31, 2007. This was after the Smart Meter Initiative was underway. THESL chose to include all suite metering costs in the Cost of Service rate application, separate from the funding for Smart Meters. This was granted in the Ontario Energy Board's decision on THESL's 2008 and 2009 rates.

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INTERROGATORY 71:

Reference(s): D1/ T8/ S 8-1,8- 5, 8-8, 8-10 to 8-13, 8-15

THESL stated that each of the Information Technology programs referenced above commencing in 2011 produce specified benefits. For each project:

a) Please discuss how the costs for these projects are accounted for in the 2010 test year including what portion of the total cost has been added to CWIP.
b) Please provide a list of projects under Information Technology that will be added to rate base in the 2010 test year as capital additions.
c) Please state the start and end date of these projects.

RESPONSE:

a) As per the table below, the forecasted balance of the IT&S CWIP account as of the beginning of 2010 is $19.1 M. As project costs are incurred, throughout the year, they are added to the CWIP account. Once the projects, or parts thereof, are implemented in the production environment, they are then energized, added to the rate base as capital additions and reduced from the CWIP account. The expected IT&S CWIP account balance at the end of 2010 is $25.1 M.

Amount Forecasted to be in CWIP as of Beginning of 2010	2010 Test Year costs	Amount Forecasted to be Energized in 2010	Amount Forecasted to be in CWIP as of End of 2010
19.1 M	33.3 M	27.4 M	25.1 M

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b) The following table lists the IT&S projects that will be added to the rate base in the 2010 test year as capital additions.

Project Name	Start Date	End Date
Project Wise	2-Feb-10	30-Jul-10
Customer Information System (CIS)	5-Jan-09	30-Jul-10
CIS Integration to other systems	14-Apr-07	8-Nov-10
Virtual Server Platform	4-Jan-10	10-Dec-10
Oracle DataGuard	4-Jan-10	29-Oct-10
Oracle Recovery Manager (RMAN)	4-Jan-10	29-Oct-10
Active Directory Migration	4-Jan-10	29-Jan-10
SM - ODS R6.X Upgrade	4-Jan-10	31-Mar-10
IAM Single-Sign-On	1-Apr-10	15-Jan-10
IAM Web Services	10-Apr-10	30-Jul-10
IAM Provisioning, IM, Intercon	4-Jan-10	30-Jul-10
IAM Customer ID, Federated ID	4-Jan-10	30-Jul-10
Treasury Manager (T-Man)	4-Jan-10	13-Dec-10
Clarity rollout to Business	4-Jan-10	13-Dec-10
HP Mercury Testing Tool & Quality Center Upgrade	4-Jan-10	13-Dec-10
Long Range HR Workforce Planning	4-Jan-10	13-Dec-10
Web Enablement Governance Framework	2-Feb-10	30-Jul-10
Outage map on the web	4-Jan-10	10-Dec-10
Customer Move Functionality on Web	4-Jan-10	31-Mar-10
Customer Display Integration - Pilot	3-Aug-10	10-Dec-10
Web Energy Portal	5-Jan-10	28-Oct-10

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Project Name	Start Date	End Date
Smart Meter - Outage Identification - Pilot	5-Jan-10	10-Dec-10
Network Meters Integration - Pilot	5-Jan-10	10-Dec-10
Network Monitoring Integration - Pilot	5-Jan-10	10-Dec-10
Smart Grid Network Security	4-Jan-10	10-Dec-10
Smart Grid Design Authority	4-Jan-10	10-Dec-10
IFRS SAP Implementation	5-Jan-10	31-Jan-10

c) Please see the table above for the start and end dates of these projects.

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INTERROGATORY 72:

Reference(s): D1/ T9/ S1

The above noted exhibit provides an overview of capital expenditures for equipment standardization totalling $32.7 million in 2010, which is an increase of $27.2 million or 495% over the 2009 bridge year and $32.7 million over the 2008 actual year.

a) Please elaborate on THESL's view that equipment standardization should be considered an 'emerging requirement' rather than a sustaining capital investment or reactive capital.

b) Please provide the most recent 5 years of historical data for this category.

c) Please provide an itemized breakdown of all proposed projects in this category.

d) Please provide the start and end date of each project.

e) Please confirm that THESL has the capacity to complete all these projects in the 2010 test year, and state what would be the consequences if some portion of these expenditures would be delayed until subsequent years.

RESPONSE:

a) Investments identified in the equipment standardization portfolio are intended to address issues resulting from legacy equipment and/or system designs which were inherited from one or more of THESL's six predecessor companies. Classifying projects identified for these reasons separately from sustaining capital and reactive capital provides a greater degree of granularity and visibility within the capital investment plan. The benefits that will result from these investments could include equipment performance improvements and minimization of long-run life-cycle costs (which overlap with the objectives of sustaining capital investments), but could also include improved public safety, reduced inventory costs, improved worker safety and

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harmonization of work and operational practices. Projects in this portfolio are distinct from projects in sustaining capital or reactive capital in that they are a direct result of non-standard legacy installations.

b) This is the first rate filing where equipment standardization has been included.

c) An itemized breakdown is provided in the table below.

Investment	Project	Estimated Cost
Handwell Standardization	Replacement of existing handwells with non-conductive design (entire unit)	$2.3M
	Replacement of existing handwell lids with non-conductive lid	$3.1M
	Grounding of existing handwells	$3.9M
Switch and Feeder Lateral Standardization	Installation of PMH pad mounted switchgear	$4.6M
	Installation of overhead fuses	$3.2M
	Installation of SCADAmate overhead switches	$8.6M
Cable Standardization	Replacement of cable supplying street lighting (with handwell replacements)	$5.2M
Transformer Standardization	Replacement of CSP transformers	$1.2M
	Replacement of solid dielectric submersible ("Turtle") transformers	$0.4M
	Replacement of submersible transforms w/ out line break switches	$0.2M

d) Exact starting dates have not yet been determined, however, all work identified in this rate filing is planned to be started and completed in 2010.

e) THESL has the capacity to complete these projects in 2010. Some of the consequences of delaying investments to later years include:

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- Deteriorating system performance;
- Higher and accelerated operating expenses associated with reactive activities; and
- Greater likelihood of high-risk low-probability events (for example, Dufferin Station outage).

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INTERROGATORY 73:

Reference(s): **D1/ T9/ S1**

THESL proposes that following its Level III contact voltage emergency response in February 2009 it needs to spend an additional $9.2 million to develop and execute a contact voltage remediation program. This program is stated as being meant to bridge the gap between the immediate "make safe" repairs completed during 2009 until when all locations are fully repaired.

a) Please confirm that the costs of $9.2 million are incremental to those for which THESL sought recovery in the 'Application for Recover of Contact Voltage Remediation Cost' (EB-2009-0243).

b) Please confirm that THESL will address all 11,000 handwells referenced on page 4 in 2010.

c) Please provide a breakdown of the $9.2 million cost estimate.

d) Please provide any cost-benefit analysis on which THESL based its decision to spend a further $9.2 million for the contact voltage remediation program.

RESPONSE:

a) Yes, the $9.2 million cost is incremental to the cost for which THESL sought recovery in the Application for Recovery of Costs related to Contact Voltage Remediation (EB-2009-0243).

b) Yes, THESL will be addressing all THESL-owned handwells, which at the time of the submission of the Application at 11,000.

c) The following table outlines the $9.2 million cost estimate for handwell remediation.

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Method of standardization	Number of handwells	Sub-total
Complete non metallic handwell replacement	1,000	$2.3M
Replace with non-metallic handwell lid only	8,000	$3.1M
Grounding	2,000	$3.8M
Total	**11,000**	**$9.2M**

d) The decision to invest in a contact voltage remediation standardization program is not based on a cost-benefit analysis. Rather, it is required to ensure that THESL fulfill its obligations under Ontario Regulation 22/04, "Electrical Distribution Safety". As a licensed distributor, the regulation requires THESL to design, build and maintain our system such that it presents no undue hazard to members of the public. From reviewing and analyzing the experiences during the Level III contact voltage emergency response in February 2009 along with other utilities who are dealing with similar problems and through working directly with the Electrical Safety Authority to ensure that proper practices and standards are in place, it is clear that THESL needs to be proactive in order to sufficiently mitigate this issue. In addition to mobile scanning and completion of the immediate follow up repairs identified during the Level III inspections, it is prudent to address the design issues at the root of the problem such that public safety is not jeopardized when assets fail. This investment will minimize the likelihood that the types of incidents which occurred this past winter and is consistent with the proactive approach undertaken by other utilities in addressing contact voltage problems.

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INTERROGATORY 74:

Reference(s): **D1/ T9/ S1**
D1/T8/S9-7/p.6

THESL has proposed an $8.6 million investment in SCADAMATE remote control switch installation in the second reference. On page 6-7 of the first reference, THESL states that SCADAMATE switches will also facilitate future feeder automation and support THESL's smart grid plan.

a) Please indicate if a portion of the SCADAMATE remote control switch investment is integrated in THESL's smart grid plan?
b) If so, please indicate what percentages of the cost are applied to the smart grid plan.

RESPONSE:

a) No, a portion of the SCADAMate remote control switch investment as identified in the reference is not integrated in THESL's smart grid plan.

b) See response to a).

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INTERROGATORY 75:

Reference(s): D1/ T9/ S5/p.4

Table 1 on this page provides a summary of externally initiated plant relocations.

a) Please provide a breakdown of the projects underlying the numbers in this table for each year shown. Please specify projects for both overhead plant relocations and underground plant relocations.

b) Please provide start and end dates for each of the projects.

RESPONSE:

PROJECTS FOR 2008

PROJECT TYPE	PROJECT TITLE	Estimated Cost ($M)	Estimated Start and Completion Dates
Underground	Bloor West Transformation	0.8	Construction Start: Mar 2008 Completion: Dec 2008
Underground	Various St. Clair Plant Relocation for Transit	8.1	Construction Start: Jan 2008 Completion: Dec 2008
Underground	Yorkdale SC Rebuild	1.8	Construction Start: Jan 2008 Completion: Dec 2008
Underground	Forest Hill rear lot	4.9	Construction Start: Jan 2008 Completion: Dec 2008.
Underground	West Diamond Rail Project	0.9	Construction Start: Jan 2008 Completion: Dec 2008
Underground	BATHURST ST PH2 [DC]	0.7	Construction Start: Jan 2008 Completion: Dec 2008.
Underground	Other Small Projects	0.8	Construction Start: Jan 2008 Completion: Dec 2008.
PORTFOLIO TOTAL		18.0	

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PROJECTS FOR 2009

PROJECT TYPE	PROJECT TITLE	Estimated Cost ($M)	Estimated Start and Completion Dates
Underground	Bloor West Transformation	1.9	Construction Start: Mar 2009 Completion: Dec 2009
Underground	St Clair Relocation for Transit	3.2	Construction Start: Jan 2009 Completion: Dec 2009
Overhead	Yorkdale SC Rebuild	1.5	Construction Start: Jan 2009 Completion: Dec 2009
Underground	Other Small Projects	0.9	Construction Start: Jan 2009 Completion: Dec 2009.
PORTFOLIO TOTAL		7.6	

PROJECTS FOR 2010

PROJECT NUMBER	PROJECT TITLE	Estimated Cost ($M)	Estimated Start and Completion Dates
Underground	External Agency - UG Relocation – College Park TTC Station	1.0	Design Start: Jan 2010 Construction Start: Aug 2010 Completion: April 2011
Underground	External Agency - UG Relocation – Cherry St Realignment	1.0	Design Started: 2009 Construction Start: Jan 2010 Completion: Dec 2010
Overhead to Underground	External Agency - OH to UG Relocation – Cherry St Realignment	0.5	Design Started: 2009 Construction Start: Jan 2010 Completion: Dec 2010
Overhead to Underground	External Agency - OH to UG Relocation – Queen W & Roncesvalles	1.0	Waiting for City's commitment for this work.
Underground	External Agency - UG Relocation – Huron & Dupont	0.5	Design Started: 2009 Construction Start: Jan 2010 Completion: Aug 2010

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PROJECT NUMBER	PROJECT TITLE	Estimated Cost ($M)	Estimated Start and Completion Dates
Overhead	External Agency - OH Relocation – New Finch W. TTC Station	0.8	Design Started: 2009 Construction Start: Feb 2010 Completion: Dec 2010
Underground	External Agency - UG Relocation - Bloor Transformation West	0.5	Design Start: Jan 2010 Construction Start: April 2010 Completion: Sept. 2010
Underground	Ext Agency - OH Relocation- Avenue Watermain from High Level PS to Lawrence	1.0	Design Started: 2009 Construction Start: April 2010 Completion: Dec 2010
Overhead	Ext Agency - OH Relocation - Neilson WM & Gerrard St E. Watermain	1.0	Design Started: 2009 Construction Start: April 2010 Completion: Dec 2010
Overhead	Ext Agency - Unplanned OH to UG Relocation – East District	0.5	Design Start: Jan 2010 Construction Start: April 2010 Completion: Sept. 2010
Overhead to Underground	Ext Agency - Unplanned OH to UG Relocation – West District	0.7	Design Start: Jan 2010 Construction Start: April 2010 Completion: Sept. 2010
Underground	Ext Agency - Unplanned UG Relocation – West District	0.5	Design Start: Jan 2010 Construction Start: April 2010 Completion: Sept. 2010
Underground	Ext Agency - Unplanned UG Relocation – East District	0.5	Design Start: Jan 2010 Construction Start: April 2010 Completion: Sept. 2010
Overhead	Ext Agency - Unplanned OH Relocation – West	1.0	Design Start: Jan 2010 Construction Start: April 2010 Completion: Dec. 2010
Overhead	Ext Agency - Unplanned OH	1.0	Design Started: 2010

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PROJECT NUMBER	PROJECT TITLE	Estimated Cost ($M)	Estimated Start and Completion Dates
	Relocation - East		Construction Start: Jan 2010 Completion: Dec 2010
Overhead	External Agency - OH Relocation – McCowan to Forthgate	1.8	Design Started: 2009 Construction Start: Dec 2009 Completion: July 2010
Overhead	External Agency - OH Relocation – Birchmount to McCowan	3.5	Design Started: 2009 Construction Start: Jan 2010 Completion: Dec. 2010
Overhead & Underground	Ext Agency - OH and UG relocation - Etobicoke-Finch West Corridor LRT	1.0	Waiting for TTC's commitment for this work
Overhead to Underground	External Agency - OH to UG Relocation – Agincourt Grade Separation	0.5	Design Started: 2009 Construction Start: Dec 2009 Completion: April 2010
Overhead	External Agency - OH Relocation - Kipling N/O Gardiner Expressway	0.8	Waiting for City's commitment for this work
Overhead	Ext Agency - OH Relocation - Mount Pleasant Watermain	0.5	Design Started: 2009 Construction Start: Jan 2010 Completion: Sept. 2010
Underground	External Agency - Union TTC Stn Expansion 2nd Platform	1.3	Design Started: 2009 Construction Start: March 2010 Completion: July 2011
Mixed	Other Small Externally Initiated Plant Relocation Projects	6.9	Design Started: 2010 Construction Start: March 2010 Completion: Dec 2010
PORTFOLIO TOTAL		27.8	

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INTERROGATORY 76:

Reference(s): D1/ T9/ S6

This exhibit describes the development of a new substation, Bremner TS, located at Bremner Boulevard and Rees Street in downtown Toronto. The proposed cost for this project in the 2010 test year is $16.3 million. On page 4 THESL has provided a list of planned activities for the 2010 test year.

Please provide a detailed breakdown of the proposed costs for the 2010 test year that is linked to the outlined planned activities.

RESPONSE:

Table 1 contains a detailed breakdown of the proposed cost for the 2010 test year that has been linked to the outlined planned activities. The outlined planned activities have been regrouped to facilitate presentation of the breakdown. The $1.1 million proposed cost in (a) of Table 1 is capital contribution to Hydro One Networks Inc. for the high voltage connection.

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Table 1: Cost Breakdown by Planned 2010 Activities ($ millions)

Planned 2010 Activities		2010 Test ($M)
(a)	• Begin connection application to HONI and IESO.	1.1
(b)	• Continuation of Environmental Assessment work, to be completed by February. • Continuation of basic design, to be completed by April. • Begin detailed design, to be completed by December, with drawing package issued for construction.	7.0
(c)	• Begin specification and procurement of long delivery items.	2.1
(d)	• Pre-construction public information centre. • Begin obtaining approvals for construction.	0.5
(e)	• Begin site formation.	5.6
	Total 2010 test year cost	16.3

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INTERROGATORY 77:

Reference(s): D1/ T8/ S8-6/p.4

THESL states that it is planning a capital expenditure of $5.16 million for the Infrastructure Maintenance/Refresh Program in the 2010 test year, which is a 39.5% increase over the 2008 historical year:

a) Please expand Table 1 “Infrastructure Maintenance/Refresh Costs” to incorporate 2004 to 2007 actuals.
b) Please provide an explanation for the increase in the category “Radio System Enhancement” to $1.60 million for the 2010 Test year from the $0.34 2008 actual level.
c) Please provide a similar explanation for ‘Firewall Security & Other Infrastructure Improvements.’ Please also provide an itemized break-down of this project.

RESPONSE:

a) The following table expands the “Infrastructure Maintenance / Refresh Costs” to incorporate the 2004 to 2007 costs.

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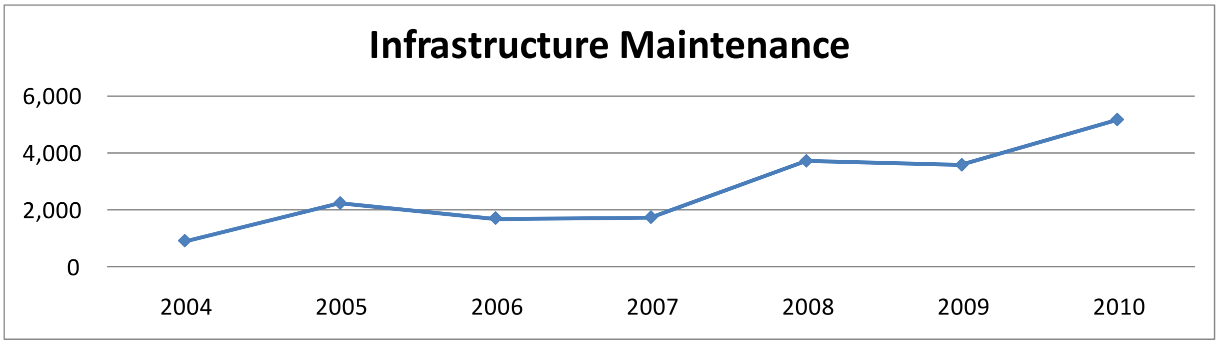
Table 1: Infrastructure Maintenance / Refresh Program 2004 to 2010.

Infrastructure Maintenance ($ 000s)						
2004 Actual	2005 Actual	2006 Actual	2007 Actual	2008 Actual	2009 Bridge	2010 Test
878	2,211	1,677	1,707	3,700	3,560	5,160



The following provides a listing of the Infrastructure Maintenance and Refresh projects implemented by THESL since 2004.

2004

- PC Refresh (548K)
- Call Centre Continuity (24K)
- EAC App Ellipse Changes - Wk Mgmt (244K)
- Itron Upgrade (24K)
- OSI PI Hist Software Upgrade (30K)
- RIMS Modem Pool - (9K)

2005

- PC Refresh (423K)
- Network Refresh (130K)
- Server Refresh (608K)

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- PI Server Interface to ACS SCADA (5K)
- Storage System for Carlton & Yonge (380K)
- Support for SD & Infrastructure Projects (180K)
- Technology Refresh of Applications (124K)
- Telephony Infrastructure & Tech Refresh (275K)
- Upgrade SCADA link with Hydro One (86K)

2006

- PC Refresh (582K)
- Data Network Technology Refresh (144K)
- DBS Support for Systems Delivery Project (6K)
- IP Technology Refresh (47K)
- Storage and Backup Tech Refresh (147K)
- AIX Server Refresh and Consolidate (126K)
- Intel Server (574K)
- Technology Refresh of Applications (50K)

2007

- PC Refresh (446K)
- AIX Server Refresh & Consolidation (96K)
- BES Server Migration (30K)
- Control Room Consolidation (26K)
- IDS/IPS (336K)
- Intel Server Technology Refresh (338K)
- Tiered Storage Implementation (296K)
- UPS Upgrade at Carlton (139K)

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b) The IT Division assumed support of the “radio system” in 2007. Basic maintenance and some upgrades were done in 2008 and 2009. A full assessment was also done of the radio system in 2008 that included: 1) confined space underground system, 2) 900MHz voice radio system, and 3) the Data Radio system that serves a mission critical communication and data feeds for both the SCADA system and the control centre.

The assessment showed that all three systems are mission critical to SCADA and the control centre, in terms of safety and functionality. The systems are more than 20 years old. Equipment is not supported and parts are not available from vendors. Replacement parts were purchased through eBay. The business case specifically highlights the goal of the radio project: eliminate radio noise within 27 antenna locations terminating to the control centre, upgrade equipment to current and supportable standards, comply with Health and Safety rules including Industry Canada and City of Toronto safety regulations, upgrade Point-to-Point MOSCAD radios, and increase MDS radio capacity.

In summary, the confined space system was upgraded in 2008 as planned. In 2009 a piece of the voice radio was updated. The increased spend for 2010 to $1.6M was to overhaul and upgrade the mission critical data radio system and the balance of the 900MHz system. This introduces supported equipment, plus it reduces the risk of failure across critical SCADA, control system, and confined space infrastructure.

c) During 2008, there were specific upgrades to the firewall and other security requirements. These included implementation of Bluecoat Proxy Server for high performance web caching together with web filtering, antivirus, and IM filtering; IPS

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Manager redundancy for high availability of the Intrusion Detection (IDS) / Intrusion Protection (IPS) management server; upgrade of IronMail software to provide the ability to detect more effectively the newer spam technologies; upgrade of McAfee's ePO software that centrally manages security for systems, networks, data, and compliance solutions. In addition, a security review of the network was performed and identified a number of key gaps to be addressed.

During 2009, the security requirements covering the three-tier network required an additional review, as well as the implementation of changes to correct the identified gaps from 2008. The 2009 security review identified the need for the implementation of an in-depth network defence and improvements to the perimeter defence. Toronto Hydro is part of the energy sector that belongs to the National Security Infrastructure of Canada. Therefore, it is important to build an efficient and effective network security platform.

As a result of this review, and to address noted vulnerabilities, the plan for 2010 includes the following breakdown:

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Table 1: 2010 Firewall Enhancements Project Costs

Component	2010 Test ($ millions)
Application Firewall	0.18
Perimeter Defence Integration	0.06
IDS/IPS Manager	0.08
Anti-Virus Manager (HA)	0.07
3-Tier Network – ongoing to 2011	0.28
Log Consolidation Control	0.26
	0.93

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INTERROGATORY 78:

Reference(s): D1/T8/S9-1

In this section, THESL provides project summary sheets for underground direct buried projects. Staff notes in this context that many of the two page summary sheets appear to be for the same projects.

For instance, Project 13120, discussed on pages 25 and 26, relates to direct buried cable for the station Scarborough/Goldhawk/Agincourt in the amount of $4,810,000. The project is given a prioritization criteria related to worst performing feeder ranking of 20 and feeder experiencing sustained interruption of 6.

Project 13122, discussed on pages 27 and 28, relates to the same feeder and is for the amount of $620,000. This project is given a prioritization criteria related to worst performing feeder ranking of 400 and feeder experiencing sustained interruption of 20.

Project 13123, discussed on pages 29 and 30, relates to the same feeder and is for the amount of $6,540,000. This project is given a prioritization criteria related to worst performing feeder ranking of 20 and feeder experiencing sustained interruption of 6.

Using the example discussed above:

a) Please explain why costs related to this feeder are divided into three separate projects.
b) Please provide an explanation as to the meaning of the prioritization criteria “Worse Performing Feeder Ranking” and “Feeder Experiencing Sustained Interruption.” In this context, please discuss why projects 13120 and 13123 have the same rankings and project 13122 has different ones.

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RESPONSE:

a) For better utilization of THESL resources (design and construction) and because of budgetary constraints, it is customary practice to stage projects (such as Goldhawk and Fundy Bay) into smaller, more manageable projects to achieve optimal scheduling. Generally the preference is to do the civil construction phase early in the year, followed by the electrical construction phase.

b) Worst Performing Feeder ("WPF") is the feeder that has performed worst over the last year based on the number of customers interrupted and the duration of the outages. Feeders are ranked based on this performance measure.

Feeder Experiencing Sustained Interruption ("FESI") is the number of sustained outages (i.e., lasting longer than one minute) experienced by a feeder over the last 12 months. The FESI ranking ignores the duration and the number of customers affected by an outage. Projects 13120, 13122, and 13123 are all related to the same feeder, which, at the time of project submission, had a WPF ranking of 20 and a FESI ranking of 6. Project 13122 was incorrectly stated as having a WPF ranking of 400 and FESI ranking 20.

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INTERROGATORY 79:

Reference(s): D1/ T9/ S7

On page 1, THESL states that as a result of the contact voltage emergency work carried out in February 2009, a number of locations were identified that require follow up work related to secondary wires to bring them up to acceptable operating condition. The total estimated cost of this work in 2010 is $6.5 million, which THESL states is incremental to the work related to standardization of handwells and secondary cables as described in D1/T9/S1.

a) Please confirm that the costs of $6.5 million are incremental to those for which THESL sought recovery in the ‘Application for Recover of Contact Voltage Remediation Cost’ (EB-2009-0243) and are incremental to the $9.2 million requested for the development of an ongoing contact voltage remediation program.

b) Please confirm that all these projects will be completed in the 2010 test year, and state what would be the consequence if some portion of these secondary upgrades would be postponed to subsequent years.

c) Please provide a summary of all capital expenditures and OM&A costs proposed for recovery in 2010 related to costs arising out of follow ups to the contact voltage remediation emergency, such as those discussed in this interrogatory.

RESPONSE:

a) Yes, the $6.5 million cost is incremental to the recovery sought in EB-2009-0243. The $9.2 million requested for the development of an ongoing contact voltage remediation program is geared toward work on standardization of the existing handwells to eliminate the possibility of contact voltage.

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b) THESL plans to complete all of the required corrective work contained in the $6.5 million estimated budget within 2010.

During the level III emergency work in 2009, repairs were made on the spot where possible using standard connectors and sealing material to make the street lighting system safe. However, there are number of locations where follow-up work is required for a proper permanent repair. Some involve installation of a fuse, replace cracked or damaged handwell lids or missing bolts while others require removal and reinstallation of underground wires between handwells because of the conditions of the existing underground wiring. As well, crews have encountered locations where poles need to be grounded using proper approved standard.

Failure to complete this follow up work in a timely manner would further weaken those stressed equipment and increase the potential for the presence of contact voltage, resulting in safety issues, reduced reliability of the street lighting system as higher costs for unplanned emergency repair.

c) In addition to this follow up work to the contact voltage remediation emergency of $6.5 million, two capital programs have been proposed related to the standardization of distribution assets supplying street lighting circuits:

- Handwell standardization, $9.2 million (refer to Exhibit D1, Tab 9, Schedule 1)
- Cable standardization, $5.2 million (refer to Exhibit D1, Tab 9, Schedule 1)

One OM&A program has been proposed related to the contact voltage remediation emergency:

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- Contact voltage scan in the predictive maintenance program, $4.0 million (refer to Exhibit F1, Tab 1, Schedule 4)

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INTERROGATORY 80:

Reference(s): **D1/T14/ S1**
J1/T2/S7

Table 1 of the first reference provides THESL's working capital allowance for the years 2008 Approved, 2008 Historical, 2009 Bridge and 2010 Test. The second reference provides a breakdown of the working capital calculation for the 2010 Test year.

a) Please confirm that THESL has not updated its lead-lag study that was filed in EB-2007-0680. If not confirmed, please provide the updated study

b) Please provide a detailed explanation of the calculations in the second reference, including how the working capital factors are calculated and, what is meant by "Net Lag Days," and what the values for these days are in the 2010 Test year.

c) Please provide supporting calculations for the years shown in table format. Please include the commodity price, wholesale market service charge, uniform transmission rates and all other rates and purchase levels used in the calculations.

RESPONSE:

a) THESL has not updated the lead-lag study that was filed in EB-2007-0680.

b) Please see the OEB's approved 2006 Navigant Lead Lag Study provided at Appendix A of this Schedule. This study was filed and approved in EB-2007-0680 for the complete details on how the working factors and Net Lag Days are calculated. The same Lead Lag Values were utilized for the current filing.

c) Please see tables provided in Appendix B for the detailed calculation of the Working Capital Allowance for each of the years requested. The details for the cost of power

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inputs requested can be found at Exhibit K1, Tab 8, Schedule 2 (corrected and filed on November 30, 2009).

NAVIGANT CONSULTING

REPORT ON LEAD LAG STUDY AND WORKING CAPITAL RESULTS USING 2005 EXPENSE LEVELS

Presented to:

Toronto Hydro Electric System Limited

toronto hydro electric system

December 4, 2006

Prepared by:

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TABLE OF CONTENTS

I. INTRODUCTION

In 2006, the Ontario Energy Board ("OEB") issued a directive to Toronto Hydro Electric System Limited ("THESL" or the "Company") requesting that the Company conduct a study of its lead/lag methodology to support its future working capital submissions before the OEB[1]. In response to the directive, the Company retained Navigant Consulting, Inc. ("NCI") to perform a lead/lag study using the most recent data available and to derive THESL's working capital requirements for the historical 2005 "test" year. The purpose of this report is to provide the results of the lead-lag study and to determine the working capital requirements of the Company's distribution business.

I.A. Working Capital and Lead/Lag Studies

Working capital is the amount of funds required to finance the day-to-day operations of a regulated utility. The determination of working capital generally relies on a lead/lag study.

A lead/lag study analyzes the time elapsed between the date customers receive service and the date that such customers' payments are available to the Company (or "lag") together with the time during which the Company receives goods and services but pays for them at a later date (or "lead"). "Leads" and "Lags" are both measured in days and are generally dollar-weighted. The dollar-weighted net lag (i.e., lag minus lead) days is then divided by 365 and then multiplied by the annual test year cash expenses to determine the amount of working capital required for operations. The resulting amount of working capital is then included as part of the Company's rate base.

[1] EB-2005-0421, Decision With Reasons, Issued April 12, 2006

Performing a lead/lag study requires two key undertakings: a) developing an understanding of how the regulated business works in terms of collections and payment policies and procedures; and b) development of a representative data set that reflects the implementation of such policies and procedures in terms of the timing of payments received (sent) at any given point in time.

To develop an understanding of THESL's operations, interviews with personnel within the regulated utility's Accounts Payable, Customer Service, Human Resources, Payroll, and Tax Departments were conducted. As in prior instances where NCI has conducted lead/lag studies, some key issues that were addressed during the course of the interviews included:

- The nature of buyers (sellers) within the business;
- The nature of the product or service, i.e., what is being sold (or bought), or, if a service was being provided;
- The time period over which the service was provided;
- Payment Terms, i.e., whether driven by government mandate, industry norms, or by company policy and the degree of flexibility within the terms for payment;
- Actual payment dates and amounts;
- Method of payment for such products (or services), e.g., cash, check, electronic;
- Expectation of changes (if any) to the Company's collections and payment policies or procedures going-forward.[2]

Operational data was obtained from THESL's Accounts Payable, Customer Service, Human Resource, Payroll, and Tax Systems. Once the data had been gathered, sampling and data validation was performed to the extent necessary and appropriate. Data validation generally took the form of comparing an actual invoice or a bill with data from the Company's systems to ensure accuracy. Except where otherwise noted,

[2] Activity over a given twelve month period is used to analyze the timing of payments and receipts unless interviews with Company personnel reveal that there are known changes to existing policies or procedures going forward. Where such changes are known, they have been incorporated into the derivation of the appropriate leads, lags, and net lags.

the lead-lag study focused on activities within THESL for the twelve months ended August 31, 2006.

I.B Organization of the Report

Section II of this report discusses the lags associated with the Company's collections of revenues. Included in Section II is a description of the sources of revenues and how they were treated for the purposes of deriving an overall revenue lag for the Company's distribution operations.

Section III presents a description of the various expenses and their attendant lead times. Included in the discussion on expense leads is the lead-time on OM&A costs, interest on long-term debt, Payments in Lieu of Taxes (such as Capital, Income, and Large Corporation Taxes), and the Goods and Services Tax (or "GST"). The methods used to calculate the expense lead times associated with each of the items as well as the results from the application of the methods are described.

Section IV sets forth a summary of THESL's working capital requirements for its distribution operations using operating expense data for the historical 2005 year.

II. REVENUE LAGS

A utility providing service to its customers generally derives its revenue from the services provided to its customers. Revenue lags represent the number of days from the date services are rendered by the Company until the date payments are received from the customers and such funds are available to the Company. Based on a review of the Company's accounting records, NCI has determined that the majority of THESL's revenues originate from two sources:

1. Residential Class, various General Service Classes, and Large User Class customers, hereafter referred to as "Bundled service ratepayers";
2. Other (miscellaneous) sources including (but not limited to) retailers, connection charges, transformer rentals and customer related jobs.

When both sources of revenues are considered together, the weighted average revenue lag time is 71.53 days. Table II-1 shows the amount of these revenues in 2005, the revenue lags associated with each revenue source, and the weighted average of all revenue sources.

Table II-1

THESL Revenue Lag

Source of Revenues	Revenue Lag (Days)	2005 Amounts (Mil $s)	Weighting Factor	Weighted Revenue Lag
Revenues from Bundled Service Ratepayers	71.76	2,687	99.17%	71.16
Revenues from Other Sources	44.66	22	0.83%	0.37
Total		2,709	100.00%	71.53

II-A. Revenues from Bundled Service Ratepayers

As shown in Table II-1, revenues from bundled service ratepayers represented 99.17% of total revenues realized by the Company during 2005. The lag time associated with the realization of such revenues was 71.76 days.

The lag associated with the Company's provision of service to its bundled service ratepayers typically consists of four components: a) Service lag; b) Billing lag; c) Collections lag; and, d) the lag associated with the Company's payment processing lag (including bank float). The contribution of each component to the overall revenue lag is shown in Table II-2, below.

Table II-2

Revenue Lag from Bundled Service Ratepayers (Days)

Revenue Lag Component	Days
Service Lag:	27.10
Billing Lag:	16.17
Collections Lag:	27.06
Payment Processing & Bank Float Lag:	1.43
Total	71.76

A discussion of each of the four components follows.

II.A.1 Service Lag

The Service Lag covers the period between the time the Company provides service and the time customers' meters are read. Interviews with the Company's customer service personnel revealed that the Company's customers have their meters read on a monthly or bi-monthly basis. Based on this information and using data from the Company's Customer Information System ("CIS") regarding the number of customers that receive monthly and bi-monthly service respectively, NCI determined that the average service lag was 27.10 days.

II.A.2 Billing Lag

The billing lag refers to the average number of days from the date the meter is read until the customer is billed. Based on the Company's monthly scheduled meter read and bill dates, NCI determined an average billing lag of 16.17 days for the twelve months ended August 31, 2006.[3]

II.A.3 Collections Lag

The collections lag refers to the average amount of time from the date the Company mails a bill to the date that THESL receives the customer's payment. For the purpose of this lead/lag study, this information was derived from an aging of accounts receivables report that showed the amount outstanding by aging day interval. Using data for the twelve-month period ended August 31, 2006, an average collections lag time of 27.06 days was derived.

II.A.4 Payment Processing and Bank Float

Based on interviews with the Company's Customer Service Department and the Company's Treasury operations, NCI determined that customer payments to the Company were typically in the form of pre-authorized payments, checks (lockbox), payments via the telephone, payments directly to financial institutions for credit to the Company's bank account, electronic payments (internet payments or direct debit payments), or payments via credit card. Using data on actual payments made and processed for the twelve-month period ended August 31, 2006, NCI determined that the weighted average lead-time associated with payment processing and bank float was 1.43 days.

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[3] This average billing lag includes the time period associated with the Company's receipt of billing data from the Ontario Independent Electric System Operator ("IESO") in order to bill its customers.

II.C. Revenues from Other Sources

Revenues from other sources represent 0.83% of the Company's total collections during 2005. The timing of receipts of such other revenues from customers depends on the Company's billing, collections, and payment processing and bank float operations. Thus, a lag time of 44.66 days was used in the derivation of the Company's overall revenue lag time as shown on Table II-1.

III. EXPENSE LEADS (LAGS)

As mentioned at the outset, a lead/lag study considers both the lag time associated with the collection of revenues from customers as well as the lead (or lag) time associated with the payment for goods and services provided to the Company by its vendors. For the purpose of this lead/lag study, the following four broad categories of expenses were considered in order to estimate the overall cash working capital requirement of the Company:

1. Cost of power;
2. Operations, Maintenance, and Administrative ("OM&A") expenses[4];
3. Interest on Long Term debt; and
4. Taxes.

Each of these categories and the associated expense lead (or lag) times are discussed below.

III.A Cost of Power

The Company purchases all of its power supply requirements from Ontario's Independent Electric System Operator (the "IESO"). Based on actual billings and the Company's payments to (or receipts from) the IESO during the twelve month period ended August 31, 2006, a weighted expense lead time of 32.61 days was derived for the cost of power.

This weighted expense lead-time includes an average service lead-time of 15.21 days since the IESO provides service to the Company on a monthly basis. The

[4] The categories included within OM&A expenses are generally consistent with those defined within the Ontario Energy Board's Distribution rates Handbook.

derivation of the expense lead-time associated with the cost of power is shown in Table III-1[5].

Table III-1

Derivation of the Expense Lead Time for Cost of Power

Service Begin	Service End	Service Lead Time	Monthly Payment Amounts	Payment Date	Payment Lead Time	Total Lead Time	Weighting Factor	Weighted Lead Time
9/1/2005	09/30/2005	15.00	200,974,640	10/19/2005	19.00	34.00	10.02%	3.41
10/1/2005	10/31/2005	15.50	184,360,107	11/17/2005	17.00	32.50	9.19%	2.99
11/1/2005	11/30/2005	15.00	161,372,179	12/16/2005	16.00	31.00	8.05%	2.49
12/1/2005	12/31/2005	15.50	202,696,412	1/18/2006	18.00	33.50	10.11%	3.39
1/1/2006	01/31/2006	15.50	162,630,421	2/16/2006	16.00	31.50	8.11%	2.55
2/1/2006	02/28/2006	14.00	156,059,276	3/16/2006	16.00	30.00	7.78%	2.33
3/1/2006	03/31/2006	15.50	86,324,877	4/20/2006	20.00	35.50	4.30%	1.53
4/1/2006	04/30/2006	15.00	138,929,508	5/16/2006	16.00	31.00	6.93%	2.15
5/1/2006	05/31/2006	15.50	169,178,427	6/16/2006	16.00	31.50	8.43%	2.66
6/1/2006	06/30/2006	15.00	165,500,488	7/19/2006	19.00	34.00	8.25%	2.81
7/1/2006	07/31/2006	15.50	184,853,295	8/17/2006	17.00	32.50	9.22%	3.00
8/1/2006	08/31/2006	15.50	192,839,849	9/19/2006	19.00	34.50	9.61%	3.32
			2,005,719,479				100.00%	32.61

[5] By ignoring the IESO creditworthiness requirements when computing the expense lead time associated with the cost of power, the Company has been conservative in estimating the working capital requirement associated with the cost of power. As it stands today, should the Company be downgraded to a BBB rating category, an additional $80 million in letters of credit may need to be posted with the IESO. More importantly, and from a working capital perspective, THESL is subject to margin calls from the IESO. If THESL's "actual exposure" (i.e., the total amount owed to the IESO) crosses a pre-determined threshold, the IESO can and does issue actual margin calls; all margin calls must be paid in cash within 2 business days of the margin call, and must be enough to reduce THESL's actual exposure down to 35% of its "maximum exposure". Margin calls posted are used as offsets against the next IESO invoice. THESL is currently in discussions with the IESO to try and change this with a view to making this less onerous. Should these discussions prove unsuccessful, THESL may have to reflect the IESO practices and recompute the expense lead time (and accompanying working capital requirements) associated with the cost of power.

III.B OM&A Expenses

The next category of expenses considered in the lead/lag study was OM&A expenses. Included within this category were the following types of expenses:

1. Payroll and Benefits;
2. Expenses associated with Consulting and Contract Staff;
3. Lease Expenses;
4. Provincial and Local property taxes; and
5. Miscellaneous Operations and Maintenance expenses.

The expense lead times associated with each type of OM&A expense are discussed below.

III.B.1 Payroll and Benefits

The category "Payroll and Benefits" consists of a number of expense-related items. A summary of the items considered, their individual expense lead times, their corresponding weighting factors, and the overall weighted expense lead time is shown in Table III-2 below.

Table III-2

Payroll and Benefits

	Amounts Twelve Months ended August 31, 2006	Lead (Lag) Days	Weighting Factor	Weighted Lead
Net Payroll - Actives	$76,577,494	11.50	52.30%	6.01
Withholdings - Actives	33,829,038	20.82	23.10%	4.81
Pensions	18,156,050	45.28	12.40%	5.61
Employer Health Tax	2,139,600	30.21	1.46%	0.44
Workers Safety Improvement Board Payments (WSIB)	955,096	45.24	0.65%	0.30
Group Medical and Dental	11,334,337	0.50	7.74%	0.04
Group Life	2,155,568	35.20	1.47%	0.52
Long Term Disability (LTD)	1,176,620	35.19	0.80%	0.28
Accidental Death and Dismemberment (ADD)	24,544	35.21	0.02%	0.01
Employee Assistance Program (EAP)	72,447	35.22	0.05%	0.02
Total	$146,420,793		100.00%	18.04

Each item in Table III-2 is discussed below.

III.B.1.1 Payroll and Payroll Related Withholdings

Based on interviews with the Company's payroll department, NCI determined that:

- All active THESL employees are paid bi-weekly on the same cycle. Payroll administration is outsourced and ADP is the payroll administrator. ADP has access to net payroll funds a day in advance of payday.
- Payroll related taxes and withholdings, on the other hand, are remitted to the respective authorities by THESL.
- All payments are via electronic funds transfer.

Based on this information and taking into account actual pay dates and amounts as well as withholding remittance dates and amounts, an expense lead time of 11.5 days was estimated for active employee payroll and 20.82 days for withholdings associated with active payroll.

III.B.1.2 Pensions

In accordance with the requirements of its pension fund administrator (The Ontario Municipal Employee Retirement System or "OMERS"), the Company is required to make contributions to OMERS on the last day of the month following the month of service. Using actual payment dates and amounts remitted and using a 15.21 day service lead time (the mid-point of the month for which a contribution is due), an overall expense lead time of 45.28 days was derived.

III.B.1.3 Employer Health Tax ("EHT")

Pursuant to the Income Tax Act, the Company is required to make monthly installment payments associated with the EHT around the middle of the month following the month of service. Taking into account actual remittances made by the Company, the remittance dates, as well as the service periods covered by those remittances, the weighted expense lead-time was calculated to be 30.21 days.

III.B.1.4 WSIB Payments

The Workplace Safety Insurance Board ("WSIB") oversees Ontario's workplace safety education and training system, provides disability benefits, monitors the quality of health care, and assists in early and safe return to work. The WSIB premium covers workers on a Corporation's payroll, either working full or part time under a contract of service or as an apprentice. Based upon WSIB coverage periods, and actual payment amounts and dates during the twelve-month period ended August 31, 2006, an expense lead-time of 45.24 days was derived.

III.B.1.5 Group Medical and Dental

During 2005-06, the Company's Health and Dental program was administered by Manulife which charges an administrative fee for services rendered and is reimbursed for claims. The Company paid the administrator daily for both the administration and claims related costs incurred by Manulife. Taking into account actual payments made by the Company, an expense lead-time of 0.5 days was estimated.

III.B.1.6 Group Life, Accidental Death and Dismemberment ("ADD"), Long Term Disability ("LTD"), and Employee Assistance Programs ("EAP")

During 2005-06, the Company's programs were administered by MEARIE, RBC Insurance, SunLife, and Warren Sheppell, which charges premiums or administrative fee for services rendered. Life Insurance premiums and administrative fees for the Company's LTD, ADD, and EAP programs are paid monthly by check typically around the 15th of the month following the month of service. Taking into account actual payments made by the Company during 2005, expense lead time estimates for: a) Group Life is 35.20 days, b) LTD is 35.19 days, c) ADD is 35.21 days, and d) EAP is 35.22 days.

III.B.2 Consulting and Contract Staff

The second type of expense which falls under OM&A expenses are those associated with Consulting and Contract Staff. Using data on invoices from vendors of services provided to the Company, NCI determined that the average expense lead-time associated with payments for consulting and contract staff was 54.78 days. The invoices included a broad spectrum of services ranging from communications and training, contract employee services, building maintenance, and architectural and other consulting related services.

III.B.3 **Leases**

The third type of expense included under the OM&A umbrella are payments made by the Company for operating leases. The Company leases office space as well as space for its communication antennas. Based on actual payments made for the leases for the twelve months ended August 31, 2006, a weighted expense lead-time of negative 14.71 days was determined.

III.B.4 **Property Taxes**

The Company makes two forms of property tax payments: a) Payments to the City of Toronto, b) PILS property taxes to the Province of Ontario. Property Taxes were paid to the City of Toronto in six installments during the current year for the current year. The first three payments were estimated and trued up in the second set of three payments. Payments were made by wire transfer. Based on actual payments made during 2005, a weighted expense lead-time of negative 28.09 days was determined.

PILS property taxes were paid to the Province of Ontario in two installments. The first was an estimate and the second consisted of a true up as well as the second payment amount. PILS Property Taxes were paid in the current year for the current year and were paid by wire transfer. Based on actual payments made during 2005, a weighted expense lead-time of 12.67 days was determined.

III.B.5 **Miscellaneous Operations and Maintenance Expenses**

Using invoices for routine goods and services provided to the Company, NCI determined a weighted average expense lead-time of 40.08 days for miscellaneous operations and maintenance related expenses. NCI's analysis took into account transactions that occurred during 2005 and, where services were provided to the Company, used the actual service periods shown on vendor invoices.

III.C. Interest on Long Term Debt

The Company has two outstanding long-term debt instruments; both of which were payable to THESL's holding company (Toronto Hydro Corporation or "THC"):

- $980 million at 5 percent. Interest was payable quarterly by THESL to THC on the last day of March, June, September, and December. Payments were made by wire transfer.
- $180 million at 6.16 percent. Interest was due semi-annually on May 7th and November 7th. Payments were made by wire transfer.

Taking this information into account, an expense lead-time of 43.23 days was estimated.

III.D. Taxes

Both income and non-income taxes, as well as pass-through taxes, must be considered in a lead/lag study when deriving working capital requirements. The categories of taxes that were considered in this study were: 1) Payments in Lieu (PIL) of Taxes including the Ontario Capital Tax and the Corporate Income and Large Corporation Tax, 2) the Debt Retirement Charge, and 3) the Goods and Services Tax ("GST").

III.D.1 Payments in Lieu of Taxes (PILs)

The Company paid its current year PILS obligations **(**Capital, Corporate Income, and Large Corporation Tax) to the province of Ontario in monthly installments and made a true up payment in or around February of the following year. Thus, the Company was pre-paying a portion of its annual tax obligation and post-paying the balance. Taking this information into account and using actual payment dates and amounts, an expense lead-time of 37.95 days (dollar-weighted by amount paid by month) was derived.

III.D.2 Debt Retirement Charge ("DRC")

DRC collections by the Company were used to retire the former Ontario Hydro stranded debt. Annual DRC amounts were paid in monthly installments to the Ontario Electric Finance Corporation (OEFC). Such payments are generally made on the 18th of every month for the month prior and are calculated based on prior month billings. Payments were made by wire transfer. Based on actual DRC payments made in 2005, a weighted expense lead-time of 33.2 days was determined.

III.D.3 Goods and Services Tax

The GST is imposed by the Federal Government and is levied at a flat rate of 6 percent. The following categories of GST were considered in this study:

1. Retail Revenues
2. Cost of Power
3. Consulting and Contract Staff
4. Lease Payments
5. Miscellaneous Operations and Maintenance Expenses

III.D.3.1 GST - Retail Revenues

The Company is obligated to collect GST from its customers and remit such collections to the Federal Government. Remittances were generally due on the last day of the month following the month in which a customer is billed for GST. Based on this information, a GST lead-time of negative 18.49 days was determined. The lead-time is shown as negative as such GST amounts which the Company was required to remit represent a source of working capital to the Company.

III.D.3.2 GST – Cost of Power

The Company is owed GST on amounts that it pays on power supplies from the IESO. Similar to retail revenues, a reimbursement generally occurs at the end of the month following the date of payment (or receipt) of funds from the IESO. Using actual dates of payments/receipts, an average expense lead-time of 43.58 days was determined and used in the derivation of the Company's cash working capital requirement.

III.D.3.3 GST – Consulting and Contract Staff

Reimbursements were made on the last day of the month following the dates on which the Company made payments on account of its retaining consulting and contract staff. Taking this information into account and using actual payment dates, an expense lead-time of 44.64 days was derived and used in the determination of the Company's cash working capital requirements.

III.D.3.4 GST – Lease Payments

Reimbursements were made on the last day of the month following the dates on which the Company made lease payments. Taking this information into account and using actual payment dates, an expense lead-time of 46.68 days was derived and used in the determination of the Company's cash working capital requirements.

III.D.3.5 GST – Miscellaneous Operations and Maintenance Expenses

As with other categories of GST, using actual payment dates on miscellaneous operations and maintenance expenses, an expense lead-time of 47.16 days was determined.

IV. THESL'S WORKING CAPITAL REQUIREMENTS

This section presents the derivation of the Company's working capital requirements using the revenue lags and expense leads discussed in Sections II and III, respectively. Table IV-1 shows the overall derivation of the Company's cash working capital requirement.[6] Footnotes 1, 2, and 3 to Table IV-1 are provided in support of the information shown in Table IV-1. As shown in Table IV-1, the net cash working capital requirement using 2005 expense levels is $298 million or approximately 12.45 percent of OM&A expenses and the cost of power. As would be expected, the cost of power is the most significant contributor to the Company's net cash working capital requirement followed by OM&A expenses. What drives the magnitude of the requirements is the significance of the net lag (i.e., revenue lag minus the expense lead time) for both these items.

[6] The dollars provided in Column E of Table IV-1, were provided by (and will be addressed by) the Company. NCI has not reviewed, nor have we expressed an opinion as to the accuracy of the figures.

Table IV-1

Calculation of THESL Working Capital Requirement

(All data in Millions $s except where otherwise noted)[7]

	Expense Item Description	**Revenue Lag (Days)**	**Expense lead (Days)**	**Net Lag (Lead) Days**	**Working Capital Factor**	**Expenses at Present Rates**	**Working Capital Requirement**
		(A)	(B)	(C)	(D)	(E)	(F)
1	Cost of Power	71.53	32.61	38.92	10.63%	2,224	236
2	OM&A Expenses	71.53	19.86	51.67	14.12%	167	24
3	Interest on Long term debt	71.53	43.23	28.30	7.73%	81	6
4	Payments in Lieu of Taxes	71.53	37.95	33.58	9.18%	61	6
5	Debt Retirement Charge	71.53	33.20	38.33	10.47%	159	17
6	Sub-Total					2,692	289
7	GST[8]					19	9
8	TOTAL (including GST)					2,711	298
9	**Working Capital as a % of OM&A including Cost of Power**						**12.45%**

[7] Strictly speaking, the Debt Retirement Charge and GST are not "expenses", but rather are "flow through expenditures".

[8] See Footnote 1 for calculation.

Footnotes 1, 2, and 3 to Table IV-1

FOOTNOTE 1: GST CALCULATION					
	GST CATEGORY	2005 Expenses (Mil $s)	6% GST	Net Lead (lag) Days	GST Benefit (Cost)
		(A)	(B)	(C)	(D)
1	Revenue	2,709	163	(18.49)	(8)
2	Cost of power	2,224	(133)	43.58	16
3	OM&A Expenses	167	(10)	46.93	1
4	TOTAL		22		9

FOOTNOTE 2: OM&A CALCULATION					
OM&A CATEGORY		Amounts for the 12 months ended 8/31/06 ($000s)	Weighting Factor	Expense Lag Time	Weighted Expense Lead Time
		(A)	(B)	(C)	(D)
1	Payroll and benefit costs	146,421	79.93%	18.04	14.42
2	Consulting and contract staff	2,586	1.41%	54.78	0.77
3	Lease Payments	357	0.20%	(14.71)	(0.03)
4	Property taxes - Province	539	0.29%	12.67	0.04
5	Property taxes - City	7,052	3.85%	(28.09)	(1.08)
6	Miscellaneous O&M	26,234	14.32%	40.08	5.74
7	TOTAL	183,188	100.00%		19.86

FOOTNOTE 3: CALCULATION OF GST LEAD TIME ON OM&A					
GST CATEGORY		Amounts for the 12 months ended 8/31/06 ($000s)	Weighting Factor	GST Expense Lead Time	Weighted Expense Lead Time
		(A)	(B)	(C)	(D)
1	Consulting and contract staff	2,586	8.9%	44.64	3.96
2	Lease Payments	357	1.2%	46.68	0.57
3	Miscellaneous O&M	26,234	89.9%	47.16	42.40
	TOTAL	**29,177**	**100.0%**		**46.93**

2008 Approved Working Capital Allowance	Expenses ($ Millions)	Working Capital Factor	Expenses * Working Capital Factor ($ Millions)
	(a)	(b)	(a) * (b)
- Cost of Power @ 10.63%	1,875.0	10.63%	199.3
- EXPENSES			
- OM&A Expense @ 14.12%	185.0	14.12%	26.1
- Interest on Long term debt @ 7.73%	63.2	7.73%	4.9
- Income and CAPITAL Tax @ 9.18%	26.4	9.18%	2.4
- Debt Retirement Charge	175.6	10.47%	18.4
- GST (See GST Lead Lag Study below)	6.3		6.3
2008 Working Capital allowance			**257.5**

	Forecast Year Amounts (Mil $s)	5% GST	Net Lead (lag) Days	GST Benefit (Cost)
	(A)	(B) = (A) * 5%	(C)	(D) = (B) * (C)/365
GST CATEGORY				
Revenue	2,387.1	119.4	-18.49	- 6.0
Cost of power	1,875.0	93.7	43.58	11.2
OM&A Expenses	185.0	9.3	46.93	1.2
TOTAL		**222.4**		**6.3**

2008 Historical Working Capital Allowance	Expenses ($ Millions)	Working Capital Factor	Expenses * Working Capital Factor ($ Millions)
	(a)	(b)	(a) * (b)
- Cost of Power @ 10.63%	1,869.3	10.63%	198.7
- EXPENSES			
- OM&A Expense @ 14.12%	174.5	14.12%	24.6
- Interest on Long term debt @ 7.73%	63.2	7.73%	4.9
- Income and CAPITAL Tax @ 9.18%	27.6	9.18%	2.5
- Debt Retirement Charge	176.0	10.47%	18.4
- GST (See GST Lead Lag Study below)	6.3		6.3
2008 Working Capital allowance			**255.5**

	Forecast Year Amounts (Mil $s)	5% GST	Net Lead (lag) Days	GST Benefit (Cost)
	(A)	(B) = (A) * 5%	(C)	(D) = (B) * (C)/365
GST CATEGORY				
Revenue	2,346.9	117.3	-18.49	- 5.9
Cost of power	1,869.3	93.5	43.58	11.2
OM&A Expenses	174.5	8.7	46.93	1.1
TOTAL		**219.5**		**6.3**

2009 Bridge Working Capital Allowance	Expenses	Working Capital Factor Lead Lag Study	Expenses * Working Capital Factor ($ Millions)
	(a)	(b)	(a) * (b)
- Cost of Power @ 10.63%	1,914.5	10.63%	203.5
- EXPENSES			
- OM&A Expense @ 14.12%	188.9	14.12%	26.7
- Interest on Long term debt @ 7.73%	64.4	7.73%	5.0
- Income and CAPITAL Tax @ 9.18%	28.4	9.18%	2.6
- Debt Retirement Charge	175.3	10.47%	18.4
- GST (See GST Lead Lag Study below)	6.6		6.6
2009 Bridge Working Capital Allowance			**262.7**

	Forecast Year Amounts (Mil $s)	5% GST	Net Lead (lag) Days	GST Benefit (Cost)
	(A)	(B) = (A) * 5%	(C)	(D) = (B) * (C)/365
GST CATEGORY				
Revenue	2,401.1	120.1	-18.49	- 6.1
Cost of power	1,914.5	95.7	43.58	11.4
OM&A Expenses	188.9	9.4	46.93	1.2
TOTAL		**225.2**		**6.6**

2010 Test Year Working Capital Allowance	Expenses ($ Millions)	Working Capital Factor	Expenses * Working Capital Factor ($ Millions)
	(a)	(b)	(a) * (b)
- Cost of Power @ 10.63%	1,994.7	10.63%	212.0
- EXPENSES			
- OM&A Expense @ 14.12%	218.8	14.12%	30.9
- Interest on Long term debt @ 7.73%	71.6	7.73%	5.5
- Income and CAPITAL Tax @ 9.18%	21.7	9.18%	2.0
- Debt Retirement Charge	174.1	10.47%	18.2
- GST (See GST Lead Lag Study below)	8.2		8.2
2010 Test Year Working Capital Allowance			**276.9**

	Forecast Year Amounts (Mil $s)	5% GST	Net Lead (lag) Days	GST Benefit (Cost)
	(A)	(B) = (A) * 5%	(C)	(D) = (B) * (C)/365
GST CATEGORY				
Revenue	2,013.5	100.7	-18.49	- 5.1
Cost of power	1,994.7	99.7	43.58	11.9
OM&A Expenses	218.8	10.9	46.93	1.4
TOTAL		**211.4**		**8.2**

INTERROGATORIES OF ONTARIO ENERGY BOARD STAFF

INTERROGATORY 81:

Reference(s): **D1/ T8/ S1 and**
D1/ T8/ S10

On page 22 of the first reference, THESL states that "the Capital Plan outlines the requirement for a $182 million investment over the ten-year period for rehabilitation of overhead distribution".

On page 6 of the second reference, the Summary of Investments for the Ten Year Plan shows projected investment for the ten year period totalling $177 million for Overhead Systems. Please reconcile these two numbers.

RESPONSE:

In Exhibit D1, Tab 8, Schedule 1, THESL states that "the Capital Plan outlines the requirement for a $182 million investment over the ten-year period for rehabilitation of overhead distribution". The amount of $182 million is the sum that was required in a ten-year period starting from 2007-2016.

In Exhibit D1, Tab 8, Schedule 10, the 2010-2019 Electrical Distribution Capital Plan states correctly the updated forecast requirement of $177 million.

INTERROGATORIES OF ONTARIO ENERGY BOARD STAFF

INTERROGATORY 82:

Reference(s): **D1/ T8/ S10**

On pages 39 and 40 THESL describes a new risk-based analysis and provides subsequent models. THESL states that "The outputs of this model have not yet been applied to THESL planning results shown in this ten-year plan but will in the near future".

Please provide a more complete explanation of this statement, discussing in general terms, the expected impacts on the 10-year plan of the new approach.

RESPONSE:

The Feeder Investment Model ("FIM") provides a risk-based approach to better prioritize replacement of distribution system assets. Optimal intervention times are identified for each asset based upon asset condition, and criticality of exiting assets and comparing this to the overall life cycle costs of replacement. In doing so, the FIM has strong potential to ensure that the right actions are occurring to the right assets at the right time and will therefore help with identifying better prioritization sequence. Early results from the preliminary FIM asset models are in alignment with the ten-year plan presented in the application. Upon full implementation of the model, it is expected that some variations will be needed within different portfolios which will be identified in yearly updates of the ten-year plan.

INTERROGATORIES OF ONTARIO ENERGY BOARD STAFF

INTERROGATORY 83:

Reference(s): E1/ T1/ S1/p.3

THESL states that: "As the past year has seen significant turmoil in debt markets and a significant widening of corporate spreads, THESL proposes to update the anticipated new debt costs closer to the beginning of the Test Year. Since the anticipated December 2009 debt issue will occur prior to the Test Year, THESL proposes that the actual costs be included in the cost of capital determination – based on the Board guidelines – at the same time the ROE and STD costs are updated."

a) Please provide a copy of this note upon issuance.
b) Please state when THESL anticipates providing the actual costs of this issue.

RESPONSE:

a) A copy of the Promissory Note is at Appendix A of this Schedule.

b) As indicated in the Promissory Note, the debt was issued at a rate of 4.54%. Exhibits E1, Tab 4 Schedules 1 and 2 have been updated to reflect this cost, plus an update to the forecast 2010 debt issue.

PROMISSORY NOTE

Principal Sum **Cdn $245,057,738.80**

FOR VALUE RECEIVED, the undersigned hereby unconditionally promises to pay to the order of Toronto Hydro Corporation ("THC") on November 12, 2019 (the "Due Date") the principal sum of **Two Hundred Forty Five Million Fifty Seven Thousand Seven Hundred Thirty Eight Dollars and Eighty Cents ($245,057,738.80)** (the "Principal Sum") in lawful money of Canada at 14 Carlton Street, Toronto, Ontario M5B 1K5, or such other place as THC may designate by notice in writing to the undersigned and to pay interest on the Principal Sum at the rate of 4.54% per annum calculated and accruing from the date hereof to the Due Date and thereafter until the Principal Sum is repaid to THC. Interest shall be calculated and payable semi-annually in arrears on the 12th of May and the 12th of November in each year at the same address with the first payment payable on May 12, 2010 where the 12th of May or the 12th of November is a Business Day. Where the 12th of May or the 12th of November is not a Business Day, then interest shall be calculated and payable on the following Business Day. For the purposes of this Promissory Note, a "Business Day" shall mean a day on which banks are open for business in the City of Toronto, Ontario but does not include a Saturday, Sunday, or a statutory holiday in the Province of Ontario. Interest both before and after default and judgment on the principal amount and overdue interest shall be payable at the aforementioned rate.

The undersigned may, at any time prior to the Due Date, repay the Principal Sum or portion(s) thereof, with accrued interest.

All payments or any part thereof may be extended, rearranged, renewed or postponed by THC. No delay or failure by THC to exercise any right or remedy against the undersigned shall be construed as a waiver of that or any right or remedy nor shall any waiver hereunder be deemed to be a waiver of subsequent default.

The undersigned hereby waives presentment, demand, protest or other notice of every kind in the enforcement of this promissory note. All amounts owing hereunder will be paid by the undersigned without regard for any equities between the undersigned and THC or any right of set-off or cross-claim.

In the event of a default hereunder the undersigned agrees to pay all expenses, including without limitation, reasonable legal fees (on a solicitor and his own client basis), incurred by THC in endeavoring to enforce its rights hereunder.

This promissory note is non-negotiable and non-assignable without the prior written consent of the undersigned.

DATED at Toronto, Ontario, this 12th day of November, 2009.

TORONTO HYDRO-ELECTRIC SYSTEM LIMITED

By: Sardana

Name: Pankaj Sardana
Title: VP, Treasurer and Regulatory Affairs

By: Lawrence Wilde

Name: Lawrence Wilde
Title: Vice President, Corporate Secretary

INTERROGATORIES OF ONTARIO ENERGY BOARD STAFF

INTERROGATORY 84:

Reference(s): J1/T1/S2

On October 15, 2009, the Board's Regulatory Audit & Accounting group issued a bulletin related to regulatory accounting and reporting of Account 1588 RSVA Power and Account 1588 RSVA Power Sub-account Global Adjustment. Please state whether or not THESL would see the necessity of making any changes to its application with respect to Account 1588 as a result of this bulletin.

RESPONSE:

THESL does not see the necessity to make any changes to its application with respect to Account 1588 RSVA Power as a result of this bulletin. However, Account 1588 RSVA Power is intended to capture all components of energy differences including the difference between the Board-approved historic loss factor and the actual loss experienced by the distributor. THESL intends to review the historic Board-approved line loss factor against the actual line loss experience by THESL, to determine whether this may amount to a dollar difference which should be either recovered from or returned to customers in a future rate application.

INTERROGATORIES OF ONTARIO ENERGY BOARD STAFF

INTERROGATORY 85:

Reference(s): J1/T1/S2

The balances as of December 31, 2008 on page 4 of the Continuity Schedule do not match the balances reported under RRR 2.1.7 for 2008 for the following accounts:

1508
1525
1555
1556
1588

For each account please provide the following:

a) State the amount reported to the Board for the account in THESL's 2008 annual filing pursuant to RRR 2.1.7.
b) Identify the components of any difference between the amount in a) and the amount reported in J1/Tab 2/ Schedule 8.
c) Explain each component of any difference identified in b). Please include an explanation of which other accounts now contain any such differences by component.
d) State which amount (the amount in a) above or the amount in exhibit J1/Tab 2/ Schedule 8 has been reflected in THESL's audited financial statements and identify the line item in the audited financial statements.
e) State which value should be relied upon in this proceeding, and, if different from the value reported in the 2008 audited financial statements, explain why the Board should rely on such different value.

INTERROGATORIES OF ONTARIO ENERGY BOARD STAFF

RESPONSE:

a) The amounts reported to the Board in THESL's 2008 annual filing pursuant to RRR 2.1.7 (December 31, 2008 trial balance in USoA format) were as follows:

Account 1508:	($2,481,461)
Account 1525:	$13,832,151
Account 1555:	$23,735,269
Account 1556:	$2,094,959
Account 1588:	$3,504,912

b) Please see response under Tables 1 and 2 below.

c) Please see responses under Tables 1 and 2 below.

INTERROGATORIES OF ONTARIO ENERGY BOARD STAFF

Table 1:

		Account 1508	Account 1525	Account 1588		Notes
Balance reported in J1/Tab2/Schedule 8:	(1)	$(73,451)	$0	$15,297,124		
Balance per THESL 2008 annual filing:	(2)	($2,481,461)	$13,832,151	$3,504,912		
Difference:	(3)=(1)-(2)	**$2,408,010**	**($13,832,151)**	**$11,792,212**		
Components of Difference:		(a)	(b)	(c)	(d)=(a)+(b)+(c)	
Reclassification accounts balances impact in the THESL 2008 annual filing	(4)	$2,039,939	($13,832,151)	$11,792,212	$0	1.
Portion of account 1508 incorrectly recorded to OEB account 1460 in the THESL 2008 annual filing	(5)	$368,071	$0	$0	$368,071	2.
Difference:	(6)=(4)+(5)	**$2,408,010**	**($13,832,151)**	**$11,792,212**	**$368,071**	

Note 1. The reclassification account balances had a net $nil impact over the 3 accounts 1508, 1525 and 1588. These reclassification accounts are used solely for THESL balance sheet presentation for regulatory assets and regulatory liabilities.

Note 2. A portion of the balance for account 1508 was incorrectly recorded in OEB account 1460 – Other Non-current assets in the THESL 2008 annual filing in the amount of $368,071.

INTERROGATORIES OF ONTARIO ENERGY BOARD STAFF

Table 2:

		Account 1555	Account 1556	Notes
Balance reported in J1/Tab2/Schedule 8:	(1)	$54,587,023	$5,254,547	1.
Balance per THESL 2008 annual filing:	(2)	$23,735,269	$2,094,959	1.
Difference:	(3)=(1)-(2)	**$30,851,754**	**$3,159,588**	
Components of Difference:				
2007 Smart Meter activity	(4)	$30,851,754	$3,159,588	1.

Note 1. The balances reported in J1/Tab2/Schedule 8 for accounts 1555 and accounts 1556 of $54,587,023 and $5,254,547, respectively, represent the 2007 and 2008 smart meter deferral activity. These balances were filed in the Quarter 4 – December 31, 2008 RRR 2.1.1 filing.

The balances reported in the THESL 2008 annual filing for accounts 1555 and accounts 1556 of $23,735,269 and $2,094,959, respectively, represent only the 2008 smart meter deferral activity. No 2007 smart meter activity was deferred in the THESL 2008 annual filing. THESL had received OEB direction in the Decision May 15, 2008 (EB-2007-0680) to include 2007 smart meter activity in rate base. THESL undertook the accounting reclassification of the 2007 SM activity variance accounts, to their applicable asset, revenue and OM&A accounts as prescribed by the OEB.

d) The amounts in exhibit J1/Tab2/Schedule 8 for accounts 1508, 1525 and 1588 (Account 1525 correctly having a $nil balance), were reflected in THESL's audited financial statements in the balance sheet line items Regulatory assets, and Regulatory liabilities.

The amounts in a) THESL 2008 annual filing for accounts 1555, 1556 were reflected

INTERROGATORIES OF ONTARIO ENERGY BOARD STAFF

in THESL's audited financial statements in the balance sheet line item Regulatory assets.

e) For account 1508, 1525 and 1588 the amounts in exhibit J1/Tab2/Schedule 8 should be relied upon for this proceeding.

For accounts 1555 and 1556 the amounts in exhibit J1/Tab2/Schedule 8 should be relied upon for this proceeding. These balances are different than the value reported in the 2008 audited financial statements; however THESL has reported in exhibit J1/Tab2/Schedule 8 the 2007 and 2008 smart meter deferral activity. These accounts have not been proposed for clearance in this hearing.

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INTERROGATORY 86:

Reference(s): J1/T2/ S8

Page 4 of the Continuity Schedule shows that as of December 31, 2008, the balance in account 1590 was a credit of $4,640,947 (total of closing principal and closing interest amounts).

Please state whether or not the rate rider associated with this account has ended and whether the balance in this account as of December 31, 2008 is reflected in the 2008 audited financial statements. If so, please state why THESL has not proposed disposition of the balance in account 1590?

RESPONSE:

The rate rider associated with account 1590 ended on July 31, 2008. The balance in the account is reflected in the December 31, 2008 audited financial statements.

THESL submitted an application for the disposition of the balance in account 1590 on December 15, 2008, "an application for disposition of amounts related to expired Rate Riders for 2006 Smart Meters, 2006 Conservation and Demand Management activities and Regulatory Asset Recovery Account." On April 16, 2009, in its decision regarding 2009 electricity distribution rates, the Board approved the disposition of the net excess rate riders collected from customers (which included the balance in account 1590), to be returned to customers over the 12-month period commencing May 1, 2009.

INTERROGATORIES OF ONTARIO ENERGY BOARD STAFF

INTERROGATORY 87:

Reference(s): J1/T1/ S2

A prior Board decision for THESL (EB-2007-0680) found that the combined PILs proceeding to deal with matters concerning account 1562 may inform matters pertaining to account 1592, and did not permit the requested disposition of this account.

Please state why THESL is proposing the disposition of account 1592 at this time, given that the referenced PILs proceeding has not concluded?

RESPONSE:

THESL has applied for disposition of this account due to the relatively large balance in this account ($11.9 million) and because it has applied to clear the majority of accounts where there are ongoing transactions in the accounts. THESL notes that even with the clearance of the account as of December 2008, amounts will continue to be booked to this account for disposition at future rate hearings. Any possible adjustments which may arise from the conclusion of the referenced proceeding can be booked to this account for disposition at a future date.

INTERROGATORIES OF ONTARIO ENERGY BOARD STAFF

INTERROGATORY 88:

Reference(s): J1/T1/ S2/ p 4, L 11 to 20

a) Did THESL obtain Board approval to record the referenced amounts related to intangible assets in account 1508?

b) What is the nature of these costs?

c) What is the basis for THESL's statement that these costs are a recoverable regulatory asset?

d) What is the regulatory precedent for collection of these costs in a deferral account and the disposition in future years?

RESPONSE:

a) THESL did not seek approval to record the referenced amounts in account 1508. It is THESL's understanding that specific approval to record amounts in an existing variance or deferral account is not required. However, THESL understands that upon application to clear any deferral or variance amounts, the appropriateness of recording any amounts is subject to Board review and approval.

b) As is referred to in the evidence referenced, Exhibit B1, Tab 11, Schedule 1, page 1, lines 19 to 23 describe the specific expenditures that have been included in account 1508. These expenditures were land easement costs related to the re-registration of easements already held by THESL as land rights allowing for the LDCs access to third party properties and training costs related to the acquisition and development of software assets (internal and external training costs).

c) THESL incurred these costs as part of its business operations, and they have been

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included rate base forming part of the Board-Approved revenue requirements in past years. Because of the change in accounting as described in Exhibit B1, Tab 11, Schedule 1, THESL can no longer record these amounts as intangible assets, and they have been removed from rate base in the current application. THESL submits that since the undepreciated costs will no longer be recovered through depreciation on rate base, that these amounts are properly recoverable as a regulatory asset.

d) THESL submits that the Board's historical use of deferral accounts to record costs (or revenues) received but which have not be included in rates is a precedent to recording such costs. Market transition costs are an example of costs which were incurred, but not included in rates, until amounts disposed of through the Regulatory Assets hearings. The collection of the amounts through rates of course depends on review of the amounts by the Board, and a determination from the Board that the costs are properly recoverable from ratepayers. THESL submits that its proposal properly follows Board precedents in that manner.

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INTERROGATORY 89:

Reference(s): J1/T1/ S2/ p 7, L 22 to 25

a) Please provide a breakdown of the IFRS costs for which THESL is seeking recovery.

b) Did THESL obtain Board approval to record these costs in account 1508? What is the basis for THESL's statement that these costs are a recoverable regulatory asset?

RESPONSE:

a) THESL is not seeking recovery of any IFRS related costs in this application.

b) THESL did not seek approval to record the IFRS amounts in account 1508. It is THESL's understanding that specific approval to record amounts in an existing variance or deferral account is not required. However, THESL understands that upon application to clear any deferral or variance amounts, the appropriateness of recording any amounts is subject to Board review and approval. THESL believes that these costs have been properly incurred and are not currently included in rates, and therefore are recoverable as a regulatory asset upon application and approval by the Board.

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INTERROGATORY 90:

Reference(s): **J1/T1/ S2/p. 2, L 17-20**
J1/T2/ S9

THESL states that carrying charges have been applied to all accounts as designated in the APH. However, the rates applied shown in Exhibit J1/Tab2/Schedule 9 differ from the Board prescribed rates for Q3 and Q4, 2009.

a) Please state whether or not this was done in error. If it was not an error, please provide an explanation for it.

b) Please recalculate all amounts using the Board prescribed rates for Q3 and Q4, 2009, and refile the schedules that are impacted.

RESPONSE:

a) At the time the evidence was developed, the Board approved rates for 2009 Q3 and Q4 were not available. The rates used for the period 2009 Q3-Q4 and 2010 Q1 and Q2 were forecasts, as described in Exhibit J1, Tab 1, Schedule 2, pages 2-3.

b) As the Board approved carrying charge rates for 2010 Q1 and Q2 remain unknown, THESL submits that updating all related evidence is unnecessary, since these amounts will change once the rates are known and THESL intends to reflect the approved carrying charges against the Regulatory Assets approved for disposal. However, THESL has calculated the impact on the amounts requested for disposal as a reduction of approximately $175K.

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INTERROGATORY 91:

Reference(s): **D2/ T1/ S1**
J1/ T1/ S2

On page 4 of the first reference, THESL proposes to track all the capital contribution variances to HONI that differ from the approved 2010 amounts in a variance account. In Exhibit J1/T1/S2, THESL explained that the basis for its proposal was the timing and amounts of capital contributions are largely out of THESL's control and are difficult to jointly forecast with reasonable accuracy

THESL further states that it has offset the shortfall in capital contributions over the years 2008 to 2009 with other capital spending, so that the variance is substantially in the mix of capital expenditures rather than their level. As such, THESL states that it does not believe it has benefitted at the expense of customers due to the capital contribution shortfall.

a) Please provide the 2008 Board Approved level of capital contributions and the actual level for the same year.
b) Please provide quantitative support for THESL's position, noted above, that it has offset the shortfall in capital contributions over the years 2008 to 2009 with other capital spending.

RESPONSE:

a) In the Board's Decision in EB-2007-0680 (page 69), the Board did not set an Approved amount for HONI Capital Contributions. The 2008 and 2009 rates were included in the proposed rates were based on contributions of $5.0 million for 2008 and $10.0 million for 2009." THESL's actual HONI Capital Contribution for 2008

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was $0.4 million; the figure of ($4.9) million in Exhibit D2, Tab 1, Schedule 1, page 1 is incorrect.

b) Quantitative support for THESL's position that it has offset the shortfall in capital contributions over the years 2008 to 2009 with other capital spending is found in Exhibit Q1, Tab 2, Schedule 1, Table 1: Summary of Sustaining Capital for 2008 and 2009 (page 7). See also Exhibit D1, Tab 7, Schedule 1, Table 2, on page 19.

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INTERROGATORY 92:

Reference(s): J1/T1/ S2/p 9-10

With respect to THESL's request for a variance account for Capital Contributions to Hydro One.

a) What is the regulatory precedent for the collection of these costs in a deferral account and the disposition in future years?

b) What is THESL's justification for this account based on the regulatory principles governing regulatory assets (e.g., materiality, prudence, causality etc.)

c) What are the journal entries projected for this account?

d) When does THESL plan to ask for disposition of this account?

e) How does THESL plan to allocate this account by rate class?

RESPONSE:

a) THESL is not aware that there is a precedent that exactly corresponds to its proposal in this case to defer variances in Hydro One capital contribution costs. Generally however it is THESL's view that the Board has provided for that kind of treatment for items that would otherwise be native to the distribution revenue requirement (as distinct from the flow-through of cost of power amounts), in cases where the amounts are material and exogenously imposed, with prudence of the expenditures being determined afterward. THESL cites market transition costs as an example.

b) The amounts in question may be material, given that THESL's materiality threshold is $1 million (as determined by the Board in the 3GIRM Report for utilities of THESL's size). The level of the potential variance will be a function of the level of the reference amount (i.e., the amount included to begin with in the 2010 revenue

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requirement), which itself will be determined by the Board.

THESL submits that since the amounts that would be recorded would result from Board-approved projects undertaken by Hydro One, which require a capital contribution under the provisions of the Board's Distribution System Code, the amounts are both exogenously required and prudently incurred, by definition.

Most fundamentally, these amounts are mandated within the regulatory framework but are difficult to predict accurately both with respect to timing and amount. THESL submits that it is unreasonable to needlessly expose ratepayers and utilities to windfall gains or losses resulting from variances between forecast and actual amounts for costs in this category, which is essentially a pre-payment to Hydro One for transmission services to be provided in the future. As such, the presumption should be that utility capital contributions to Hydro One for transmission facilities are treated in a manner consistent with periodic payments made by utilities for those same services.

c) The precise journal entries have yet been determined and will ultimately depend on what precise approval is granted by the Board. However, in principle THESL's proposal is to defer the revenue requirement consequential to any variance between the approved amount of capital contributions to Hydro One and the actual amounts.

d) Upon finalization of the capital contribution for each project, the variance if any between the reference amount and the actual amount will be calculable and available to be cleared in THESL's subsequent rate case. Unless the amount is immaterial, THESL would normally apply to clear balances at the next opportunity after they are known.

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e) THESL takes the view as noted above that capital contributions to Hydro One are in the nature of a pre-payment for transmission services (if transmission rates were sufficiently higher, the required capital contribution would be eliminated). Therefore the costs, both of any reference amount that is approved by the Board, and of any subsequently approved variance amount, would be allocated in the same manner as transmission costs.

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INTERROGATORY 93:

Reference(s): L1/T1/S1

Please explain why in THESL's cost allocation model the GS>50<999 RIMs and Non RIMs customers are treated separately in the input tables, but are combined in the output tables.

RESPONSE:

In preparation for the OEB's 2006 Generic Cost of Service filing, individual load profiles were developed for each of these two rates classes. THESL received approval to merge these two rate classes in its EB-2007-0680, however since the Cost Allocation model had been developed based on these classes being separate, and since THESL maintains separate data for each of the classes, until THESL makes modifications to the Cost Allocation model we continue to use the existing model for consistency. Since there is only one class for rate making purposes, only the single class is presented in output tables.

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INTERROGATORY 94:

Reference(s): L1/T2/S1/p.3 and pp. 5-7

Page 3 of the above reference "Summary Financial Information" shows "Total Distribution Assets" of $4,141,256,158, "Accumulated Amortization" of $2,255,857,193 and "Net Fixed Distribution Assets" of $1,885,398,966.

Page 7 of above reference, which is the final page of "Sheet I4 Breakout Worksheet – First Run," shows the same "Net Fixed Assets" number of $1,855,398,966, but a different breakdown between total assets and amortization of $4,375,963,597 and $2,490,564,631respectively.

a) Please provide an explanation for these differences.
b) Please explain why THESL used the aggregated "Summary Financial Information" sheet rather than Sheet I3 Trial Balance, which shows each account.

RESPONSE:

a) The differences are due to presentation between the "Summary Financial Information" and the "Sheet I4 Breakout Worksheet – First Run". The attached spreadsheet (labelled Appendix A) provides a reconciliation of the differences. This is by design of the OEB's Cost Allocation model.

b) The aggregated "Summary Financial Information" was used because it is the prescribed method in the OEB's Cost Allocation model.

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94) Ref E L1/T2/S1/p.3 and pp. 5-7

a) Explanation:
The Table below provides a reconciliation of the differences identified.
The differences between the "Summary Financial Information" and the "Sheet I4 Breakout Worksheet - First Run" are due to the presentation of "Contributed capital - account 1995", and the "Directly Allocated - accumulated depreciation", as follows:

In the Break Out Worksheet the capital contribution account 1995 of ($260,927,182) is deducted after arriving at the "Grand Total" figure of $4,375,963,597, per Model design.

In the Break Out Worksheet the accumulated depreciation on Directly Allocated capital costs is included in arriving at the "Grand Total" figure of $4,375,963,597, per Model design.

Table: Reconciliation of "Summary Financial Information" to "Sheet I4 Breakout Worksheet - First Run":

Summary Financial Information:		
Distribution Assets	**4,141,256,159**	**A**
Accumulated amortization	**-2,255,857,193**	**B**
Net Fixed Distribution Assets	1,885,398,966	
2010 Cost Allocation Information Filing - Sheet I4 Break Out Worksheet:		
Total assets, before inclusion of contributed capital account 1995:	4,375,963,597	**a**
Deduct: Contributed capital	-260,927,182	
sub-total	4,115,036,415	
Add back: Direct assignment accumulated depreciation included in a, (per model design)	26,219,744	
Summary Financial Information - Distribution Assets above	**4,141,256,159**	**A**
2010 Cost Allocation Information Filing - Sheet I4 Break Out Worksheet:		
Accumulated depreciation:		
Accumulated depreciation - 2105	-2,218,459,862	
Accumulated depreciation - 2120	-11,177,587	
sub-total	-2,229,637,449	
Add back: Direct assignment accumulated depreciation included in a, (per model design)	-26,219,744	
Summary Financial Information - Accumulated amortization	**-2,255,857,193**	**B**

Note: Directly Allocated breakdown:

Cost	50,983,418
Accumulated depreciation	-26,219,744
Net Assets	**24,763,674**

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INTERROGATORY 95:

Reference(s): **L1/T2/S1/p.3 and pp. 5-7**

On these pages, THESL makes a number of direct allocations to specified customer groups of certain accounts.

a) Please provide an explanation for each of the direct allocations which have been made.

b) Please state whether or not when THESL makes a direct allocation to a class, the rest of the account is allocated 0% to the class or classes that received such a direct allocation. If THESL does not make such an adjustment, please discuss whether the class is being properly allocated a share of the account over and above the amount that is allocated directly.

RESPONSE:

a) Feeders – Direct allocations have been made to feeders in accordance with Chapter 5 – Direct Allocation, Board Directions on Cost Allocation Methodology for Electricity Distributors (Cost Allocation Review – EB2005-0317 Chapter 5.1).

Each feeder direct allocation is 100% dedicated to customers in the same rate classification and these direct allocations impact the GS>50 RIMS, GS>50 – Intermediate and Large Users > 5 MW rate classifications. The direct allocation for feeders captures associated costs. These directly allocated feeder costs capture the gross value, accumulated depreciation, depreciation expense and any contributed capital. The direct allocation also includes associated O&M activities. Accounts impacted are:

- 1840 Underground Conduit

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- 1845 Underground Conductors and Devices
- 2105 Accum. Amortization of Electricity Utility Plant
- 5040 Underground Distribution Lines and Feeders – Operation Labour
- 5045 Underground Distribution Lines & Feeders – Operation Supplies & expenses
- 5150 Maintenance of Underground Conductors and Devices
- 5705 Amortization Expense – Property, Plant and Equipment

Transformers Ownership Credit is treated as part of the revenue requirement in the OEB's Cost Allocation Study and the model distributes these costs to customers that utilize the LDC's line transformers (LTNCP allocator). Customers that do not utilize the LDC transformation are not allocated any of these transformer allowance costs. THESL does not believe this is an appropriate allocation since the allowance itself is intended to offset all transformation costs for all customers.

THESL has modified the model through identifying the transformer allowance provided to specific rate classes and directly assigned the appropriate transformer costs to those rate classes.

b) Customer classes that received the direct allocation will also receive a portion of the balance of any residual. Even though a specific feeder is directly assigned to one customer class, under emergency situations access to other feeders is required.

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INTERROGATORY 96:

Reference(s): L1/T1/S1/p.4
L1/T 2/S1/p.24

Sheet 01 "Revenue to Cost Summary Worksheet – First Run" of the second reference above provides a line entitled "Revenue Requirement (Includes NI)" which allocates revenue requirement to each of THESL's customer classes.

Please provide an explanation for the differences in the revenues allocated by customer class on this sheet when compared to Table 3 of the first reference above. For instance Sheet 01 shows a revenue requirement for the residential class of $257,094,597, while Table 3 shows allocations to the residential class ranging from $202.6 to $221.2 million.

RESPONSE:

Sheet 01 is the Cost Allocation results without any adjustments for the proposed Cost to Revenue Ratio results. The values shown in Table 3 (Exhibit L1, Tab 1, Schedule 1, page 4) are the revenue requirements from the various rate classes after adjustments to arrive at the proposed Cost to Revenue Ratio shown in Table 2 (Exhibit L1, Tab 1, Schedule 1, page 3).

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INTERROGATORY 97:

Reference(s): **L1/T2/S1/p.9**
M1/T 4/S1/p.1

THESL's total base revenue (including Transformer Ownership Allowance) is $540,468,543 on both Sheet I6, the first reference above and the "2010 Revenue Reconciliation Summary," which is the second reference above. However, the class by class amounts are different.

Please provide an explanation for these differences.

RESPONSE:

As described in Exhibit R1, Tab 1, Schedule 96, the values in Exhibit L1, Tab 2, Schedule 1, page 9 are the initial rate class revenue requirement before any adjustments were applied to arrive at the proposed Cost Revenue Ratios. Rate class revenue requirement in Exhibit M1, Tab 4, Schedule 1, page 1 are the final revenue requirement after adjustments.

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INTERROGATORY 98:

Reference(s): **K1/T3/S2**
K1/T8/S2
L1/T2/S1/p.56
N1/T2/S2/p.2

The first reference, which is Table 1 of Exhibit K1, Tab 3, Schedule 2 provides "Weather-normalized Loads by Class," which are used in THESL's load forecast. For the 2010 Test year, total kWh of 24,865,322,485 and kVa of 42,949,353 are shown.

The second reference, which is Table 1 of Exhibit K1, Tab 8, Schedule 2 provides "Cost of Power Forecast Inputs." For the 2010 Test year, total purchased energy kWh of 25,755,312,099 is shown along with system network kW of 47,042,108, line connection kW of 46,349,983 and transformer connection kW of 47,615,738.

The third reference, which is Exhibit L1, Tab 2, Schedule 1, page 56 of THESL's 2010 Cost Allocation Informational Filing shows 12 NCP Distribution NCP (Total System) allocations which include 22.16% to Residential, 12.05% to GS<50 and percentage allocations of the same type for THESL's other customer classes.

The fourth reference which is Exhibit N1, Tab 2, Schedule 2, page 1, 2010 wholesale transmission allocation shows 12 NCP allocations which include 25.4% to Residential, 11.8% to GS<50 and percentage allocations of the same type for THESL's other customer classes. This reference also uses the same system network, line connection and transformer kW as the second reference.

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a) Please explain the relationship between Total kVA in the first reference and the three kW quantities in the second reference.
b) Please explain why the latter quantities are more suitable for the forecast of cost in the fourth reference "2010 Wholesale Transmission" than those from the first reference.
c) Please explain why the allocation 12NCP used for RTSR Connection rates in the fourth reference is different than the 12NCP allocation used in the Distribution cost allocation in the third reference.

RESPONSE:

a) Numbers in both references are consistent with 2010 test year total purchased energy kWh forecast (25,755,312,099).

Table 1 from the first reference contains class loads after losses (customer class portions of the purchased energy divided by class loss factors). To get class kVA from class purchased kWh, the historical relationship between kWh and kVA based on the billed statistics was applied. Total kVA in the first reference is the sum of class kVAs derived independently as described above. These demands are used for billing purposes and are non-coincident.

Three kW quantities in Table 1 from the second reference were derived from the total purchased energy 2010 forecast (25,755,312,099 kWh) based on THESL historical relationship between total purchased energy and System Network kW (measured at Ontario system peak), Line Connection kW and Transformer Connection kW (both measured at utility peak). These demands, which are at the system level, are used for cost of power purposes.

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b) System demands are what determine Cost of Power, not class level demands.

c) The 12 NCP allocators used for RTSR Connection in the fourth reference were not derived from the 12 NCP allocators in the third reference but from Exhibit L1, Tab 2, Schedule 2, page 17. For the residential class the 26.4% is calculated by dividing the residential DNCP12 kWh by the total DNCP12 kWh (13,303,145 / 50,438,590 = 26.4%). The 12 NCP allocators in the third reference includes adjustments for Peak Load Carrying Capacity ("PLCC") which are needed for the OEB's Cost Allocation Minimum System methodology.

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INTERROGATORY 99:

Reference(s): M1/T2/S2/p.6

THESL's proposed Tariff of Rates and Charges includes a distribution loss factor for customers greater than 5,000 kW of 1.0141.

Please provide a description of the connection characteristics that would explain the level of this loss factor.

RESPONSE:

Large customers are connected to the primary system. The primary system generates fewer losses due to reduced resistance and higher voltages, thus lower losses.

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INTERROGATORY 100:

Reference(s): **M1/T1/S1/p.8**

On this page, THESL provides reasons why it believes that the current level of loss factors should be maintained even though the most recent five-year average is below the current approved level.

In discussing the levels of the loss factors, THESL notes that: "Some reduction in losses is expected as overall loads are reduced. Reduced losses can also be expected as more efficient equipment replaces older equipment over time."

Please further explain why, in light of the statements made above, THESL is not convinced that the recent declines in losses indicate a sustained trend.

RESPONSE:

As shown in Exhibit M1, Tab 5, Schedule 1, up until the most recent two years of data, the loss factor was fairly stable. Only in 2007, and more so in 2008, has there been a large change in the loss factor. The 2009 year-to-date information filed in response to an interrogatory in Exhibit R1, Tab 3, Schedule 51, indicates that losses are higher again in 2009. The reduction in losses attributable to the replacement of older inefficient equipment with newer more efficient equipment is not enough to explain the large reductions in a single year. Due to both the stability up until recent history, the rise in the 2009 year-to-date loss factor, and the already low losses exhibited on the system as compared to other LDCs in the province, THESL has requested to maintain the current loss factor. If additional evidence (i.e., more data) suggest continued experience with

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lower losses, THESL will apply for a lower loss factor in its next filing. Any variances are resolved through a variance account.

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INTERROGATORY 101:

Reference(s): G1/T1/S1

a) In 2010 and 2011 will there be any impact on asset management spending which is attributable to the Green Energy and Green Economy Act ("GEGEA"), and more specifically, smart grid and renewable energy generation?

b) If yes, please describe.

RESPONSE:

a) It is expected that in 2010 and 2011, smart grid and renewable energy generation will have an impact on asset management spending which is attributable to the *Green Energy and Green Economy Act*.

b) Smart grid and renewable energy generation will impact asset management spending, as it introduces new opportunities and requirements to planning and operations, such as in terms of bidirectional power flow and increased network monitoring. There needs to be development of current asset management operations consistent with THESL's planning process as outlined in Exhibit C1, Tab 6, Schedule 1, as well in terms of:

- Studies, pilots and demonstrations;
- Strategy, policy, standards, and supply chain; and
- Education and training

At this time THESL is unable to quantify the financial impacts of the above.

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INTERROGATORY 102:

Reference(s): G1/T1/S1

Please provide the proportion of total distribution costs included in this application that is attributable to GEGEA related projects.

RESPONSE:

Since distribution cost is not a defined term in THESL's application, two figures are calculated in response to this question, for GEGEA related costs as a proportion to operating and capital expenses, as summarized in Table 1.

Table 1: Proportion of capital and operating expenses attributable to GEGEA projects

Distribution		GEGEA[3]		Proportion of GEGEA	
Capital [1] ($M)	Operating[2] ($M)	Capital ($M)	Operating ($M)	Capital (%)	Operating (%)
423.6	212.1	9.77	0.45	2.31	0.21

[1] Exhibit D1, Tab 1, Schedule 1, Table 2

[2] Exhibit J1, Tab 2, Schedule 3

[3] Exhibit G1, Tab 1, Schedule 1, Table 1

There are no other GEGEA costs in the 2010 EDR Application.

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INTERROGATORY 103:

Reference(s): F2/T9/S1/p7/L7

The referenced line refers to IT&S training in preparation for fulfilling a role in assisting Smart Grid goals, and that these training costs can no longer be capitalized under the IRFS rules and the new Canadian GAAP rules.

a) What amount of IT&S training has been allocated to eligible Green Energy Act activities?

b) Does this relate to incremental activities as defined in the June 16, 2009 Guidelines?

RESPONSE:

a) Training costs allocated to eligible Green Energy Act activities amount to $70 K.

b) This amount relates only to incremental activities as defined in the June 16, 2009 Guidelines related to the implementation of a Smart Grid in Ontario. Understanding that the Smart Grid initiatives are an evolving technology, these educational activities will take advantage of current Smart Grid programs and events in progress in Ontario (i.e., through participation with the Ontario Smart Grid Forum), where possible.

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INTERROGATORY 104:

Reference(s): F2/T9/S1/p.4

Table 1 on this page states that IT&S costs are $25.2 million in the 2010 Test year. Please state the portion of the IT&S payroll costs that has been allocated for eligible Green Energy Act activity and the basis for this allocation?

RESPONSE:

The portion of the IT&S internal resource costs that have been allocated for eligible Green Energy Act activity is $595 K. This amount will indirectly affect payroll through internal recoveries from the capital projects associated with the Green Energy Act activity. This allocation has been based on several factors including:

1) Availability of internal resources scheduled to work on eligible Green Energy Act activity;
2) Minimum ratio desired in internal vs. external labour resources, in accordance with IT&S strategic direction; and
3) Expected availability of capital funds for eligible Green Energy Act activity in 2010.

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INTERROGATORY 105:

Reference(s): G1/T1/S1/p1

The Board in its June 16, 2009 Guidelines provided for Deferral Accounts for renewable Generation Connection and Smart Grid Development Expenditures for recording incremental investments or expenses.

a) Please confirm that the applicant is not seeking relief under the Board's June 16, 2009 Guidelines including a GEA funding adder.
b) If the applicant is seeking relief under the Guidelines, what specific relief is the applicant seeking from the Board in this application related to eligible Green Energy and Green Economy Act ("GEA") facilities?
c) Is THESL seeking to have any of the costs of GEA initiatives allocated to provincial ratepayers (as per Reg. 330), as opposed to merely THESL ratepayers? If yes, please indicate the applicable amount for each initiative.
d) If yes, please describe which costs, and provide the calculation THESL proposes for such an allocation.

RESPONSE:

a) THESL confirms that it is not seeking relief under the Board's June 16, 2009 Guidelines including a GEA funding adder.

b) Not applicable.

c) At this time, THESL is not seeking to have any of the costs allocated to provincial ratepayers for its GEA initiatives.

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d) Not applicable.

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INTERROGATORY 106:

Reference(s): **G1/T1/S1/p1**

Table 1 on page 1 shows THESL plans to spend $9,770, 000 in capital costs and $450, 000 in operating costs for a total of $10, 220, 000 on smart grid projects. The Board's Guidelines indicate smart grid investments should currently be limited to pilot type projects.

a) Please indicate which of the capital and OM&A costs relate to projects which are not pilot projects?
b) Please explain to what extent each of the projects (i.e., pilot and other) have been subject to business case analysis, and provide the analysis for each.
c) If they have not been subjected to a business analysis, please explain why.

RESPONSE:

a) For Smart Grid operations projects as listed in Table 2 of Exhibit G1, Tab 1, Schedule 1, page 11, all of the related capital and OM&A costs are for demonstration purposes as indicated in the Board's Guidelines.

   For Smart Grid IT&S projects as listed in Table 3 of Exhibit G1, Tab 1, Schedule 1, page 12, the related capital costs are split between demonstration projects and foundational study projects required to enable the operations and the IT pilot projects. Those foundational study projects are needed to ensure proper grid security, network readiness and scalability of the pilot projects and are pre-requisites to the pilot projects. They consist of the following initiatives:

   1) Integration Architecture and Design;
   2) Internal Network readiness; and

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3) Smart Grid Network Security.

b) Each of the smart grid projects has been subjected to qualitative analysis intended to actively explore the needs of developing the Smart Grid in compliance with provincial mandate and in meeting utility and distributed generation requirements. THESL also has the responsibility to explore, be familiar with, and apply new technologies considering the uniqueness of its customer base and infrastructure. However, the projects have not gone through an economic assessment as explicit benefits and costs have yet to be measured. The primarily purpose of the demonstration is to learn about the technology, its impact on THESL operations, and to collect information which will enable THESL to further evaluate the potentials of project deployment.

The value proposition and rationale for each of the 2010 initiatives are discussed in Exhibit G1, Tab 1, Schedules 2 and 3. Each project is fully aligned with the Smart Grid objectives as described in Exhibit G1, Tab 1, Schedule 1, page 5.

The 2010 operations projects were selected from the 25-year roadmap based on the criteria discussed in Exhibit G1, Tab 1, Schedule 1, page 10, and the 2010 IT&S projects were selected to enable those 2010 operations projects, and to lay out the foundation required for future Smart Grid initiatives.

c) See response to part b) above. However, economic assessments have not yet been done.

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INTERROGATORY 107:

Reference(s): G1/T1/S1/p1/Table 1 & p 11/Table 2 & p 12/Table 3

Please provide clarification as to what part of the Exhibit G1 Smart Grid Plan is incremental to existing projects and what constitutes normal system expansion and development.

Please provide such clarification by providing the following separately for each project listed for which THESL is seeking rate relief in the above references:

a) A description of how each of the initiatives fits within the Distribution System Planning guidelines of June 16, 2009 in the categories of
   i. Renewable Generation Connection Capital
   ii. Renewable Generation Connection OM&A
   iii. Smart Grid Capital
   iv. Smart Grid OM&A
b) A statement for each of the initiatives as to whether or not there have been expenditures in the years prior to 2010 on each initiative, and if so, why the amounts for 2010 can be considered incremental, as defined in the June 16, 2009 Board guidelines.
c) The expenditure for each activity in each of the years 2010 and for subsequent years.

RESPONSE:

a) The initiatives fit within the Distribution System Planning Guidelines in the categories as shown in Tables 1 and 2 below.

INTERROGATORIES OF ONTARIO ENERGY BOARD STAFF

Table 1: 2010 Smart Grid Projects – Operations

Initiatives	Category	Description
Feeder Automation	Smart Grid Capital	Demonstration of feeder automation scheme applied to intelligent switches to perform self-healing capabilities
Secondary Network Automation	Smart Grid Capital	Demonstration of incorporating remote monitoring and automated control capabilities into the underground secondary network
Transformer Smart Metering	Smart Grid Capital	Demonstration of smart meters installed on distribution transformers to for advanced monitoring capabilities
Power Line Monitoring	Smart Grid Capital	Demonstration of communicating sensors installed on overhead conductor lines for advanced monitoring capabilities
Submersible Vault Monitoring	Smart Grid Capital	Demonstration of vault monitors on submersible distribution transformer vaults for advanced monitoring capabilities
Environmental Protection	Smart Grid OM&A	Studies, development of planning methodologies, and education/training to prepare for distributed generation, plug-in electric and hybrid electric vehicles, and home energy management solutions

INTERROGATORIES OF ONTARIO ENERGY BOARD STAFF

Table 2: 2010 Smart Grid Projects – Information Technology

Initiatives	Category	Description
Customer Portals Pilot	Smart Grid Capital	Demonstration of different customer interfaces, customer web energy and OMS portals
Smart Grid Metering Pilot	Smart Grid Capital	Demonstration of smart meter's ability to remote connect/disconnect, smart meter outage identification, network meters integration and network monitoring integration
Integration Architecture & Design	Smart Grid Capital	Plan for the extension of SOA architecture for Smart Grid
Access Network Pilot	Smart Grid Capital	Demonstration of WiMax to secure network connection between Smart Grid devices and THESL's back-end communication system
Internal Network Readiness	Smart Grid Capital	Plan for the extension of THESL's network architecture to prepare for Smart Grid
Smart Grid Network Security	Smart Grid Capital	Create Smart Grid security best practices and design network security to mitigate penetration risk

b) All initiatives identified in Exhibit G1 are incremental, as they are not included in previous capital plans approved by the Board or funded through current rates. Descriptions of the incremental components are provided in Tables 3 and 4 below.

INTERROGATORIES OF ONTARIO ENERGY BOARD STAFF

Table 3: 2010 Smart Grid Projects – Operations

Initiatives	Description
Feeder Automation	New or retrofitted switches, communications, and integration into control room applications
Secondary Network Automation	New microprocessor relays, sensors, and SCADA communications installed on an existing underground secondary network vault, to enable remote monitoring and automated control capabilities
Transformer Smart Metering	New monitoring devices installed on distribution transformers, including smart meters and voltage/current sensors
Power Line Monitoring	New sensors installed on overhead conductor lines
Submersible Vault Monitoring	New monitoring devices installed on distribution transformers, including smart meters, and voltage, current, flood, and temperature sensors
Environmental Protection	New studies, planning methodologies, and education/training to prepare for distributed generation, plug-in electric and hybrid electric vehicles, and home energy management solutions

INTERROGATORIES OF ONTARIO ENERGY BOARD STAFF

Table 4: 2010 Smart Grid Projects – Information Technology

Initiatives	Description
Customer Portals Pilot	Pilot of different customer displays, web energy portal and OMS Portal
Smart Grid Metering Pilot	Pilot of smart meter's ability to remote connect/disconnect, smart meter outage identification, network meters integration and network monitoring integration
Integration Architecture & Design	Study and plan for the required extension of SOA architecture to enable Smart Grid
Access Network Pilot	Pilot WiMax to secure network connection between smart grid devices and THESL's back-end communication system
Internal Network Readiness	Study and plan for the required extension of THESL's network architecture to prepare for smart grid
Smart Grid Network Security	Study of the Smart Grid security best practices and the planning for network security to mitigate potential penetration risks.

c) Tables 5 and 6 provide a near term forecast of the expenditure for each activity for 2010 until 2012. The forecast assumes successful demonstration of the initiatives and that projects move into a deployment phase.

INTERROGATORIES OF ONTARIO ENERGY BOARD STAFF

Table 5: 2010 Smart Grid Projects – Operations

Initiatives	2010 ($000s)		2011 ($000s)		2012 ($000s)	
	Capital	Expense	Capital	Expense	Capital	Expense
Feeder Automation	2680		2000		3000	
Secondary Network Automation	115		500		1000	
Transformer Smart Metering	184		500		1500	
Power Line Monitoring	41		200		500	
Submersible Vault Monitoring	10		100		500	
Environmental Protection		450		500		500

INTERROGATORIES OF ONTARIO ENERGY BOARD STAFF

1 **Table 6: 2010 Smart Grid Projects – Information Technology**

Initiatives	**2010 ($000s)**	**2011 ($000s)**	**2012 ($000s)**
	Capital	**Capital**	**Capital**
Pilot Projects			
Customer Portals Pilot • Customer Display Integration – Pilot • Web Energy Portal • OMS Integration - Customer Portal	948		
Smart Grid Metering Pilot • Smart Meter Connect / Disconnect Pilot • Smart Meter - Outage Identification – Pilot • Network Meters Integration – Pilot • Network Monitoring Integration - Pilot	420		
Integration Architecture & Design	880		
Access Network Pilot	1,248		
Internal Network Readiness	1,480		
Smart Grid Network Security	1,764		

2

INTERROGATORIES OF ONTARIO ENERGY BOARD STAFF

Initiatives	2010 ($000s)	2011 ($000s)	2012 ($000s)
	Capital	Capital	Capital
Implementation Projects			
Customer Portals		200	500
Smart Grid Metering			1,400
Access Network		5,000	5,000
Home/Vehicle Projects		5,800	4,200
Network Projects		1,400	400
IT Operations Projects		1,000	600
Grid Projects		550	6,500
Demand Generation Projects		200	3,500

The costs for 2011 and 2012, as shown in Tables 5 and 6 above are preliminary costs that will be reassessed over the next few months.

INTERROGATORIES OF ONTARIO ENERGY BOARD STAFF

INTERROGATORY 108:

Reference(s): G1/T1/S1/p4

The paragraph titled "Long-Term Plan" refers to a detailed plan "Connecting the Smart Grid". It indicates that the plan will be adapted for filing with the Board following receipt from the Board of the further-developed distribution system plan filing guidelines referred to in the Board's letter to distributors dated June 16, 2009.

a) Please provide a copy of "Connecting the Smart Grid".
b) Please state whether or not THESL is seeking any funding or cost recovery with regard to the long term plan in this application. A statement for each of the initiatives as to whether or not there have been expenditures in the years prior to 2010 on each initiative, and if so, why the amounts for 2010 can be considered incremental, as defined in the June 16, 2009 Board guidelines.

RESPONSE:

a) Please see Appendix A of this Schedule.

b) THESL is not seeking any funding or cost recovery with regard to the Long-Term Plan "Connecting to the Smart Grid" as referenced in this Application.

Toronto Hydro-Electric System Limited
EB-2009-0139
Exhibit R1
Tab 1
Schedule 108
Appendix A
Filed: 2009 Nov 30
(73 pages)

CONNECTING THE SMART GRID

STRATEGIC DEPLOYMENT OF TORONTO'S ELECTRICITY NETWORK OF THE FUTURE

March 20 2009

TABLE OF CONTENTS

EXECUTIVE SUMMARY

Electricity has been a primary driver for change in the 20th century. Toronto's electricity network (the "grid") has been built to service the City of Toronto for over 95 years, providing a fundamental necessity of life, for comfort, security, entertainment, and upholding the economy in this financial capital of Canada. Our society has become increasingly dependent on reliable, high quality electricity, and this has made the electricity grid a critical and necessary infrastructure.

However, the electric grid cannot be assumed to continue delivering its services indefinitely without a significant change. The grid is faced with an abundance of risks that are increasing in size, scale, and complexity. The infrastructure is aging and demands are increasing, making it ever more difficult to maintain reliability and integrity after years of underinvestment. Simultaneously, customers in the digital era are accustomed to highly reliable, real time services, with abundant information exchange, options, control, and instant feedback. Additionally, customer loads have increased substantially with little additional investment in the existing distribution infrastructure. Finally, environmental protection has become a key priority in the political agenda and in the minds of the public.

These growing pressures are now presenting a convergence of risks that overlays all of a utility's strategic decisions regarding the future. It is calling for an immense task for innovative alternatives and creative problem solving. It requires a shift in the industry that requires everyone's collaborative efforts.

This effort, coined as "smart grid", is a paradigm shift that represents the single greatest transformation in the history of the electric utility, an evolution of how it functions in its social, economical and environmental contexts. The vision is here, and the challenge now lies in translating that vision into action. The grid must be strategically renewed and prudently invested, applying innovative concepts and technologies, to deliver the service that is needed in the 21st century.

Defining the Smart Grid

A smart grid can be defined as the strategic application of advanced information, communications, and electrical/electronics technology, to optimize the operation and control of the electric infrastructure, to meet customer requirements and enhance their experience, and to promote environmental sustainability. It refers to a network of intelligence, through smart systems, smart processes, and smart people. It is not a one-time installation program, but a continuously evolving grid, keeping abreast of technological advances and seeking opportunities for the betterment of the grid. Smart grid is also about being connected, connecting the grid with its customers, new technologies, and the environment.

The Case for Change

The vision of smart grid is based on the realities that the electricity industry is facing today. Utilities must respond to these realities to continue providing services for its customers, the society, and the environment. The key drivers for change include:

- **The Ontario Green Energy Act** – provincial initiative that can enable Ontario to become a North American leader in renewable energy and green economy.
- **City of Toronto's Climate Change Plan** – commitment for Toronto to become the renewable energy capital of Canada.
- **Electrification of transportation** – shift in the transportation industry to plug-in electric and hybrid electric vehicles (PHEVs), as well as expansion of electric public transit.
- **Energy security** – a convergence of risks with an aging infrastructure, congestion, price volatility, system losses, cyber and physical security risks, and need for workforce renewal.
- **Customer expectations in a digital era** – focus on community values and environmental actions, need for tools to manage electricity use, preferences to install distributed generation, need for consistent high power quality to meet digital electronics requirements, and the demand for better experience with the utility.

Toronto's smart grid is seen as the plug that connects environmentally mindful customers to the grid in a digital era. Benefits of the smart grid, summarized at a high level, include:

- **Customer benefits** – access to timely information, control, and options to better manage their energy use and carbon footprint, as well as improved experience with the utility.
- **Social and economic benefits** – job creation, economic growth through infrastructure investments, opportunities for coordination and shared services, and increase in public safety and quality of life.
- **Environmental benefits** – cultivate culture of conservation, promote green generation, and reduced environmental footprint.
- **Utility benefits** – improved reliability, "digital grade" power quality, ensuring security of supply, better management of assets, operational efficiencies, accommodate distributed energies, deferral of infrastructure expansions, improved revenue management, and protection against security threats.

Challenges and Costs of Deployment

While the smart grid has significant potential to deliver value, it represents a significant endeavour. Research and development is needed to break through knowledge and technology barriers. Technology solutions will take time to develop, mature, and be ready for commercialization. Communication and engineering standards will need to converge.

Building Toronto Hydro's smart grid will require a framework of intelligence, energy, communications, strategy, legislation, regulation, and stakeholders' commitment. A coordinated innovation effort will consist of a solid integration and synchronization of decentralized systems, processes and organizational structure. The workforce will require new competencies. Security measures must be put in place. Business processes, operating procedures, and work protection will have to incorporate the new paradigm of a smart grid.

Progressive and timely legislation and regulation will be instrumental towards its success. Disincentives from rates must be removed to recognize the benefits of conservation and energy efficiency, as well as accounting for socioeconomic and environmental factors. Customer education and adoption of new technologies will further need to be assisted by retailers and service providers. Utilities will have to approach customers with transparency and address their specific yet evolving needs.

The costs and time required, as well as the benefits attained, will depend on the scope and pace of implementation, technology trends, and customer acceptance and adoption, and is thus not straightforward to quantify. Costs and benefits are typically shared amongst a wide mix of projects rather than in isolation, investments are made to account for future requirements, and benefits often extend into socioeconomic and environmental contexts.

Careful investments and guiding strategies will be utilized to mitigate the risks of initial deployments and ensure that early benefits are attained. Given that investments in the Advanced Metering Infrastructure (AMI) have been mandated by the government, and that some of the building blocks for the smart grid are already in progress and maturing within Toronto Hydro, it is expected that additional costs for smart grid deployment will include incremental spending to accelerate maturing of the in-progress building blocks, implementation of new smart grid solutions, and in integrating various programs/solutions.

Vision and Mission

The vision for smart grid is ***an intelligent, continually innovative electricity network***. Intelligence refers to the “smartness” of the grid, including self-healing, robustness, fast, reliable, and having optimized solutions. This smartness is harnessed through continual innovation, where new solutions and methods are strategically applied to the electric system and its services.

In addition, the mission is *to* ***modernize to deliver value in meeting customer needs and expectations of the 21st century***. This includes modernizing the infrastructure, communications, and even processes, culture, and the services it provides to customers.

Smart Grid Objectives

Toronto’s smart grid has three key objectives. The first objective is in ***climate protection and sustainable energy***, in particular to meet the requirements of the Ontario Green Energy and Green Economy Act, City of Toronto’s Climate Change, Clean Air, and Sustainable Energy Action Plan, and Canada’s Kyoto Protocol targets. We need to achieve the following:

1. Targeted reduction of environmental footprint, working towards a zero carbon, zero waste organization by closely monitoring, tracking, and controlling our and helping our customers manage their environmental footprint.
2. Accommodate a large variety and high penetration of distributed generation and storage options.
3. Provide customers with programs and streamlined processes for the connection of renewables, clean generation, and conservation efforts.
4. Support the reliable connection of microgrids, community energy, and virtual power plants in the Toronto Hydro system.
5. Enable an electrified transportation infrastructure, including full and plug-in electric hybrid vehicles, subway systems, and electric trains.

The second objective is to ensure ***energy security***, to deliver electricity that is safe, reliable, and efficient. Thus we need to:

1. Invest prudently in an aging infrastructure to manage risks and to provide high levels of reliability.
2. Provide the visibility and control throughout the network, working towards a self healing and fault anticipatory network, and connect high levels of distributed energy sources.
3. Monitor and manage power quality levels and its impact to customers.
4. Improve the efficiency and effectiveness of utility operations.
5. Incorporate physical and cyber security measures.

The third objective is to provide ***customer satisfaction in the 21st century.*** Smart grid opens up new and exciting opportunities for us to work together with our customers, who value trust, service excellence, transparency, performance, and reasonable rates. Thus, the utility should:

1. Provide timely information that empowers actions and improves experience with the utility, such as their environmental footprint, energy consumption, outage and restoration notifications, costs and cost projections, budget constraints, utility programs.
2. Offer new forms of communications for customers to have readily available access to utility information, such as web services, email notifications, text messages, online chat-rooms, blogs, and through in-home devices. Multilingual services are also required.
3. Enable energy management controls such as in-home displays, smart thermostats, and smart home appliances, with intuitive, user friendly interfaces.
4. Provide new forms of customer service models that suit their preferences, such as on-line self-services, voice recognition systems, changing billing payment periods, and prepayment options.
5. Offer advices on conservation and saving costs, reducing carbon footprint. Rewards for conserving. Allows integration of renewable energies and plug-in hybrid vehicles with simplified processes.
6. Potentially provide incentives and financial support to sustain reduced energy consumption and environmental footprint, especially for low income households.

Strategic Principles

Strategic principles are simple, understandable, actionable statements that reflect an organization's strategy to achieve a vision. It should empower all stakeholders to move towards the smart grid vision.

The first strategic principle is to ***harness innovation – throughout the grid***. This calls for innovation through applying intelligence in the system – intelligent people, intelligent business processes, and intelligent technologies. This intelligence is to be applied throughout the grid, creating an "end-to-end" smart system, including beyond the meter to assist customers in conserving, managing energy usage, and incorporating renewable energies, as well as partnering with upstream transmission system and other distribution networks in global optimization.

The second strategic principle is to ***explore synergies by integrating systems***. The greatest value from a smart grid is not from the development of independent initiatives, but from the integration of its various technologies and services, and to maximize the use of available data and information. This is a holistic approach to smart grid. The action to realize such synergies comes from integrating systems, such as between people to work collaboratively, between strategies and plans for alignment and leverage, between technologies for enhanced functionalities, and between services for added value.

The third strategic principle is to ***develop an innovation support structure***. The true strength of smart grid arises when innovation is accompanied by a support structure. This structure directs, guides, and focuses efforts on constructive innovation and filters out disruptive ones. It also implies the application of business processes management, mechanisms to quickly turn trends into actions, measures to sustain innovation, training and education, stakeholder engagement, and technology support.

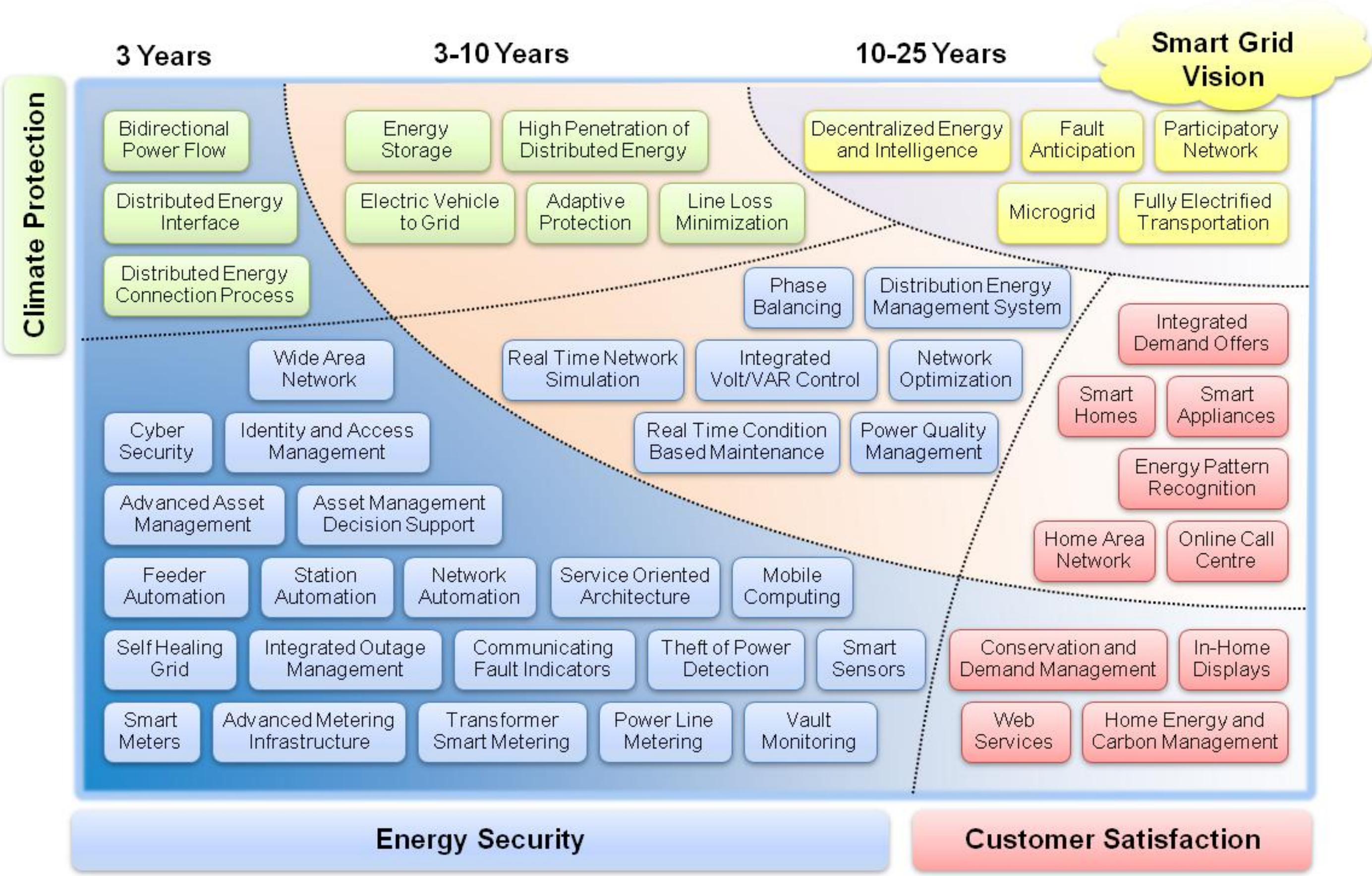
Strategic Roadmap

The role of the strategic roadmap is to translate the smart grid vision into a set of actionable programs and projects. It was developed based on identifying the infrastructure, services, technologies, research and development efforts, as well as core/baseline business and technical requirements needed to achieve the objectives of the smart grid. Highlights from the roadmap are shown in Figure E1.

The **3 year plan** of the smart grid roadmap is to establish *Toronto's Smart Community*. This is a demonstration area where prioritized initiatives can be tested, processes developed, customer acceptance understood, and operating procedures created. Emphasis will be on maturing and accelerating existing smart grid building blocks, as well as integrating building blocks to realize cross-functional services, shared costs, and added values.

Expected benefits will be demonstrated and measured, and used to support potential full scale deployment. The goal is to generate short term wins, and validate the value of smart grid. Additional opportunities and potentials will also be identified for further demonstration. Results and lessons learned will be shared regularly in various forms of communication, such as white papers, presentations, and online content.

Initiatives that were selected as a part of this demonstration area are characterized by relative certainty and value, typically utilizing established, proven technologies to demonstrate immediate value for the customer, society, and the environment. These projects are typically in progress and maturing at Toronto Hydro, or planned to commence in the next three years. For more uncertain initiatives, it is expected that given the pace of industry adoption and effort into advancing smart grid technologies, in 3 years time there will be increased certainly and convergence into technology trends, communication standards, customer responses, and government priorities and regulations.



The **3-10 year plan** involves the expansion of demonstrated initiatives from the smart grid community into larger scale deployments. Simultaneously, additional initiatives will be demonstrated, as characterised by requiring technological advances and solutions, requiring new or convergence of standards, and building on the foundations of the 3 year plan.

Finally, the **10-25 year plan** represents the end state of the smart grid as defined by present drivers. Initiatives are characterised by complete integration of technologies and services, collaboration between the utility and customers, and energy sourced primarily from renewable and clean generation. Proven smart grid technologies will span across the entire territory of Toronto Hydro. There will be further focus on providing services rather than resolving technology barriers.

Key Recommendations

The key recommendations resulting from the research and analysis in this report are presented below. They represent necessary and fundamental steps for the successful launch of smart grid at Toronto Hydro. Implementation of these recommendations is not consecutive, but overlap in a number of instances.

KEY RECOMMENDATIONS FOR LAUNCHING SMART GRID

1 Engage and align with external stakeholders for Toronto's Smart Grid Plan	• Align with the Government of Ontario's Green Energy and Economy Act (Bill 150) upon legislation and regulation • Collaborate with the City of Toronto for the application of smart grid to address the City's Climate Change Plan • Coordinate with the Ontario Energy Board to expedite effective smart grid regulation • Educate Customers
2 Launch campaign on Toronto's smart grid	• Develop communications strategy and plan • Launch internal campaign to educate and engage internal staff on smart grid • Launch external campaign for customers and the industry • Attract new workforces and strategic partnerships
3 Convene steering committee, innovation and sustainability office, and working group	• Steering Committee for executive monitoring and key decision making • Innovation and Sustainability Office to centralize strategic planning and management of overall smart grid portfolio. Align with external industry and government priorities. • Working Group with representation of key stakeholders in the organization for program execution
4 Training and education	• Develop and strengthen key competencies required for smart grid • Allocate sufficient resources to build momentum and reach tipping point • Capable of designing, developing, and operating the smart grid • Extend training and education to customers
5 Develop business plan for Smart Grid Community	• Develop detailed implementation plan with program scope, technology selection, costs and options, and business case • Integrate plan with 10 year capital plan and Electricity Distribution Rates filing process

A Call to Action

The City of Toronto has been known as the hub of Canada – the financial hub, the cultural hub, and the entertainment hub. With firm dedication and collaboration from the Ontario government, Toronto government, Toronto Hydro, and other key stakeholders, Toronto can also become the intelligent and sustainable energy hub of Canada. The smart grid is the avenue to make this happen.

Through innovation and the strategic application of information, communication, and electronic/electrical technologies, the smart grid can optimize the electric infrastructure in a time of a convergence of risks, enhance customer experience in a digital era, and meet the province and city's agenda for environmental sustainability and a green economy.

Guided by our vision, objectives, strategy, and roadmap, we can realize a path through the challenges of deployment into a future of innovation and sustainability. The recommendations in this report envision actions taken by stakeholders throughout the organization to work collaboratively towards a smart grid. The time is right, and the time is now.

1 INTRODUCTION

Smart Grid: From Vision to Action

> **"We need a 21st century electricity grid that can better meet the changing nature of power consumption in Ontario. A smarter grid is essential to maximizing the energy from Ontario's abundant natural solar and wind energy"**
>
> *Premier Dalton McGuinty*

Electricity has been a primary driver for change in the 20th century. Toronto's electricity network (the "grid") has been built to service the City of Toronto for over 95 years, providing a fundamental necessity of life, for comfort, security, entertainment, and upholding the economy in this financial capital of Canada. Without electricity, the world will not be as we see it today – subway systems, telecommunications, information technologies, commercial centres, manufacturing industries, entertainment systems, electronic commerce, etc., will no longer perform its function. Our society has become increasingly dependent on reliable, high quality electricity, and this has made the electricity grid a critical and necessary infrastructure.

However, the electric grid, which has served the population of Toronto well for many decades, cannot be assumed to continue delivering its services indefinitely without a significant change. Our lights may be on, but the grid is faced with an abundance of risks that are increasing in size, scale, and complexity. The infrastructure is aging and demands are increasing, and it becomes increasing difficult to maintain reliability and integrity after years of underinvestment. There is not much time left before the grid reaches its very limits. This is made difficult by an aging workforce, as well as increasing security concerns. There needs to be renewed focus on the need for sustaining the electrical infrastructure. The status quo is just not enough.

Simultaneously, we see significant growths in other industries, which undertook great development driven by innovation and improving customer service. The Information Technology and Telecom explosions of the 1990's, in particular the rise of the Internet, have changed the way we live and open up vast opportunities for better standards of living. Customers are accustomed to highly reliable, real time services, with abundant information exchange, options, control, and instant feedback. Hence, we're in a *smart era* – smart phones, smart computers, smart business, smart cars and smart people. It is time for utilities to come onboard and to offer customers the service they expect in the 21st century.

Finally, environmental protection has become a key priority in the political agenda and in the minds of the public. The message is clear, that the effects of climate change have become increasingly evident, and we must act now. The Ontario Government (Ministry of

Energy and Infrastructure) has put forward the Green Energy Act to drive a green energy system, while the City of Toronto has defined its Climate Change Plan.

These growing pressures are now presenting a convergence of risks that overlays all of a utility's strategic decisions regarding the future. It is calling for an immense task for innovative alternatives and creative problem solving. It requires a shift in the industry that requires everyone's collaborative efforts.

As described in IBM's report on *Plugging in the Customer*, "Collectively, these drivers are overturning traditional assumptions about energy consumers and the fundamental value proposition of the industry itself. Though each of these trends has progressed independently for a time, they have all now reached a point of convergence where each is fuelling the others and the entire combination is catalytic"[1]. Also, according to CEATI's *Electric Distribution Utility Roadmap, Phase II: Common Infrastructure*, "It becomes clear that the industry as a whole could not survive if it chose to remain on the traditional, "Business as Usual" path"[2].

It is now a time for change. We need a change towards a grid that encourages energy conservation and efficiency, accommodates large amounts of renewable and clean energy sources, and reduces carbon emissions and environment footprint for all. We need a grid that provides information and options to customers to make informed decisions about their energy usage and supports an advanced and electrified transportation system that substitutes electricity for oil. We need a grid that continuously innovates, optimizes the grid's operation, and enhances system reliability and security. We need a grid that enables a greener economy with greener jobs. To accomplish this, we need a smarter energy grid. Coined as "smart grid", this is a paradigm shift, a fundamental change in the electric utility business.

The smart grid represents the single greatest transformation in the history of the electric utility, an evolution of how it functions in its social, economical and environmental contexts. The vision is here. The perfect storm has arrived. The challenge now lies not in the vision, but in translating vision into action, by navigating a path through this perfect storm. There is no silver bullet, and grid must be strategically renewed and prudently invested, applying innovative concepts and technologies, to deliver the service that is needed in the 21st century.

---

[1] IBM Global Business Services, "Plugging in the Customer," Available at: http://www-05.ibm.com/de/energy/pdf/plugging-in-the-consumer.pdf

[2] CEATI, "Electric Distribution Roadmap: Common Infrastructure," Available at: http://www.ceati.com/pdetails.php?id=5962

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- Marketing and Communications
- Metering Technologies

- Policy and Standards
- Regulatory
- Stations and Distribution Automation
- System Reliability Planning

2 DEFINING THE SMART GRID VISION

2.1 DEFINING TORONTO HYDRO'S SMART GRID

In February of 2009, the Ontario Ministry of Energy and Infrastructure introduced Bill 150, the Green Energy Act, to the Legislative Assembly of Ontario. The act defines the smart grid as follows:

> ***"Smart grid" means the advanced information exchange systems and equipment that when utilized together improve the flexibility, security, reliability, efficiency and safety of the integrated power system and distribution systems, particularly for the purposes of,***
>
> ***a) Enabling the increased use of renewable energy sources and technology, including generation facilities connected to the distribution system;***
>
> ***b) Expanding opportunities to provide demand response, price information and load control to electricity customers;***
>
> ***c) Accommodating the use of emerging, innovative and energy-saving technologies and system control applications; or***
>
> **d)** ***Supporting other objectives that may be prescribed by regulation.***

Hence, the following observations can be made about the province's view of the smart grid:

- Smart grid is the use of advanced information exchange systems and equipment in the electrical grid
- It's objective is to improve the flexibility, security, reliability, efficiency, and safety of the grid
- This applies both to the integrated (bulk) power system, the distribution system, and end use
- It is applied for the purpose of increasing the use of renewable generation, for conservation, and providing customers with information and empowering them with energy controls and information to manage their energy consumption
- It serves as a platform to support further and emerging applications that may be prescribed by regulation

It is commonly described that the "smart grid" means different things to different people. Hence it is vital to understand its definition as it relates to the unique context of the City of Toronto. Applying the government's definition of the smart grid, Toronto Hydro has developed the following definition:

A smart grid can be defined as the strategic application of advanced information, communications, and electrical/electronics technology, to optimize the operation and control of the electric infrastructure, to meet customer

requirements and enhance their experience, and to promote environmental sustainability.

In this definition, the following should be noted:

- It refers to smart systems, smart processes, and smart people, working together to realize the new paradigm of a truly "smart" grid
- The term *smart utility* can be used synonymously to the smart grid, expanding from its focus on technology alone
- It is also not a one-time installation program, but a continuously evolving grid, keeping abreast of advances in the industry and seeking opportunities for the betterment of the grid

Smart Grid as a Network of Intelligence

A smart grid can be visualized as a *network of intelligence* through connecting building blocks in the grid. This is illustrated in Figure 1, which divides the path of intelligence into the three areas of Customer/Field, Communications, and the Office. Each contains a set of "building blocks" which participate in this flow of intelligence. Customer and Field devices generate data, which is transferred through communication channels into the Office. Office contains intelligent process and applications that translate data into useful information, and is relayed to people who receives the information and is translated into knowledge. This knowledge can then be used to make intelligent business decisions, which in turn is returned to the grid as grid intelligence and control. Note, in some cases, people may only be informed and based on established algorithms/logic, actions may be directly communicated back to grid intelligence.

This architecture exemplifies how a smart grid can utilize smart systems, processes, and people to optimize the grid. There are, of course, more complex dynamics of the flow of intelligence within the system, such as:

- Distributed intelligence within the field without human intervention
- Strategic decisions made to enable a policy directive (e.g. use of green energy)
- Customers managing their own energy usage through information made available to them from in-home devices

Nevertheless, a smart grid highlights the value-add of intelligence throughout the energy delivery chain, whether the intelligence is centrally managed by the utility or distributed throughout the grid.

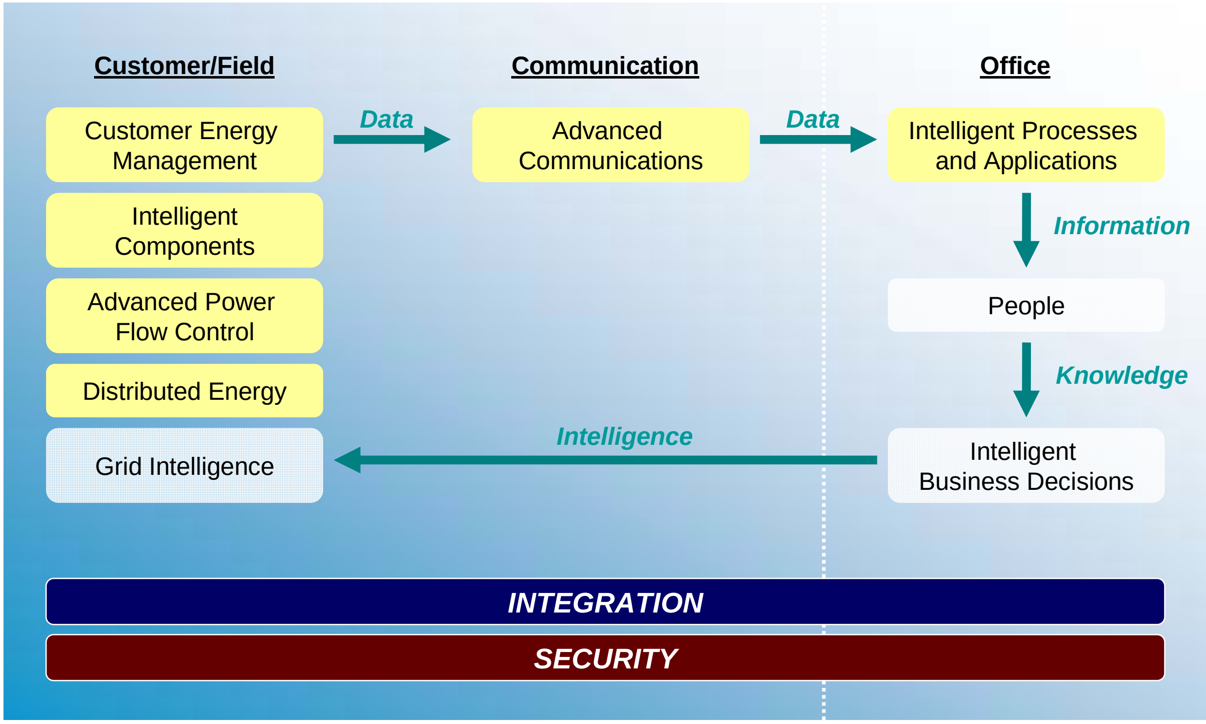

Figure 1: Illustrating the architecture of a Smart Grid, including enabling components and the flow of intelligence throughout the grid.

Furthermore, the fundamental building blocks of smart grid are not entirely new. Traditionally, the latest technologies have been applied in the electrical grid in the form of SCADA (supervisory control and data acquisition/distribution automation), enterprise systems, conservation and demand management, and more. However, the smart grid brings an emphasis of innovation to achieve certain objectives (e.g. environmental sustainability), and true innovation arises when traditionally separate functions are integrated to offer new services. Another key distinction of the smart grid is the attention to the need for security, which is further required as the grid becomes increasingly integrated.

This model closely resembles the connection of the Internet, where numerous data nodes share information through a robust communication system, enabling a decentralized intelligence network.

Smart Grid Characteristics

Tables 1 and 2 describe some of the common characteristics of a smart grid.

TABLE 1: 10 KEY CHARACTERISTICS OF A SMART GRID

Dynamic	Knowledge of the quality of power being delivered by every delivery point in the system, whether from the transmission system, or from attached storage, or distributed generation.
Adaptable	Ability to adapt the system to the incoming power quality and quantity, thereby reducing demand or improving power quality in an active and adaptive manner.
Anticipatory	Knowledge of the conditions of the grid, including conductor stress and temperatures in critical areas, device-induced noise or other problems that could lead to future failures, as well as knowledge of what those possible failure modes are.
Self Healing	Knowledge of how to adapt to failures, and minimize the duration and severity of the failure, without having to create multiple redundant systems.
Sensitive	Understanding of how each customer is consuming energy from the grid, usage patterns in the past and projections of future usage.
Low Cost	Ability to be built and maintained at a reasonable cost, with the maintenance being done on an as-recognized basis, rather than by rote.
Flexible	Ability to deploy new equipment and capabilities without having to completely redeploy or replace existing technologies or to do a wholesale system hardware upgrade. Wherever possible, devices should be capable of taking software upgrades to improve capabilities and the central system should be able to use raw data to create the new knowledge required.
Fast	Systems and components should be able to communicate and exchange data without having to spend much time converting data or routing data through central systems. Standards should exist at the communications protocol level and at the data level. Communication solutions must satisfy data latency requirements.
Intelligent	Intelligence is distributed into the grid. No single point of failure in the system should be able to knock out the ability of the overall grid to function. Movement of information and knowledge to the central level should be done for business reasons only and, as much as possible, by exception.
Living	The grid needs to be able to adapt to changing conditions and needs over time, so that as the needs of customers evolve, so does the grid.

Source: CEATI, *Electric Distribution Utility Roadmap, Phase II: The Case for Change*

TABLE 2: 12 ADDITIONAL CHARACTERISTICS OF A SMART GRID

Interoperable	Open architecture, promoting interoperability between vendor products.
Plug and Play (PnP)	PnP architecture for intelligent devices, controllers, and small generation facilities (e.g. home solar, micro to small wind turbines), to expedite the connections process.
Multidirectional	Power and information can travel in multiple directions and multiple paths, under full control.
Efficient	Losses and switching time are minimized.
Low Tolerance	Low tolerance for interruptions, power quality, safety, etc.
Digital Grade	Provide "digital grade" power quality suitable for modern electronics.
Distributed Intelligence	Processing and decision making is not centralized at the utility, but distributed throughout the entire power flow chain.
Real Time	Real time sensing, measuring, analyzing, and decision making, when required.
Customer End-Point Oriented	More emphasis on the "last mile" of service to the customers, focusing on affordability, reliability, power quality, and demand side management. Increased customer participation in their energy use, and established trust in the utility for information and services.
New Performance Measures	Performance indices addressing reactive power, power quality, and asset conditions.
Intelligent Asset Management	Operate assets much closer to design margin, while expanding lifetime by automating at the optimal operating conditions. Substitute "iron" with "bits" by utilizing intelligence to delay expensive capital investments. Base decision models on progressing goals and probabilistic and stochastic analyses rather than historical performance.
Competitive Energy Markets	Support variable rates and energy accounting.

Note that while all of these characteristics may be desirable for the smart grid, certain solutions will emphasize specific characteristics and prohibitive costs may keep all from being fully achieved.

2.2 SMART GRID BUILDING BLOCKS

Smart grid is composed of an integration of building blocks, each of which carries its key characteristics. These building blocks include:

- Customer Energy Management
- Intelligent Components
- Advanced Power Flow Control
- Distributed Energy
- Advanced Communications
- Intelligent Processes and Applications

This section discusses the smart grid vision along each building block.

Customer Energy Management

Traditionally the only feedback to a customer regarding its energy usage is a bill at the end of the billing cycle, typically 30 to 60 days after the period in which they consumed the electricity. They are uninformed regarding their energy usage, how they can save electricity and thus their costs, as well as the impact of their energy use to the environment. Moreover they did not necessarily have the tools to allow them to obtain this information, save costs, or reduce their environmental footprint.

With the advent of a smart grid, customers will have the tools and information available to become more aware in their energy usage and enabled to make informed decisions. They will have access to multiple communication channels to access utility information. They will be offered a variety of options to manage and control their energy usage. They will become more aware of their environment impact and are encouraged to think in carbon footprints.

The vision is in moving towards a "participatory network", as described in IBM's report on *Plugging in the Customer*[3]. This is a dynamic energy ecosystem where customers and utilities work together, sharing responsibilities and benefits, to achieve core objectives such as maintaining quality of life, reducing costs, and minimizing environmental impact.

Intelligent Components

Intelligent components form the fundamental intelligent building block of the smart grid. They can be distributed sensors, providing visibility throughout the grid. They further generate data and have communication capabilities amongst each other and back to the office for centralized processing and control.

[3] IBM Global Business Services, "Plugging in the Customer," Available at: http://www-05.ibm.com/de/energy/pdf/plugging-in-the-consumer.pdf

They enable utility operators to gain visibility into the grid, perform conditions-based monitoring, provide alarms of vault floods, fires and intrusion, anticipate faults through identifying fault signatures, etc., and make localized intelligent decisions on the course of actions and perform diagnostics.

This also includes components that incorporate the latest advances in materials engineering and equipment design, such as superconductivity and advanced power electronics.

A recent example of intelligent components are smart meters, which are distributed units throughout the grid, and capable of mutual communication with a backhaul for central processing. They enable local monitoring of power usage, with ever growing capabilities such as remote disconnect, power quality measurement, load control, detection of meter tampering, and even as gateways into a home area network (HAN). They are fully scalable to multi-million meter deployments, allow open, two-way communications. When integrated with other systems such as back-office meter data management, they can enable a wide array of other functions, such as outage and restoration notification, energy loss calculations and demand management.

Advanced Power Flow Control

When intelligent components are integrated and used in conjunction with high voltage equipment, they can be utilized for advanced power flow control. Examples include:

- Self-healing grid – automatic fault detection, location, isolation, sectionalisation, and restoration to minimize the impact of an outage.
- Integrated Volt/VAR Control (IVVC) – integrated operation of reactive compensators (e.g. capacitor banks), voltage regulators, and tap changers to control the system's voltage and reactive power, optimizing voltage profile and minimizing energy loss.
- Load balancing – monitoring and control of the loading between phases and feeders, and redirecting loads for phase balancing and away from congested areas, to lower losses and increase system capacity.
- Power conditioning – use of controllable reactive power compensating devices to restore the system's power quality. Examples include DSTATCOMs (Dynamic Static Compensators) and SVCs (Static VAR Compensators), which are being used on the transmission systems today. Potentially distributed energy sources, in particular inverter-based generation, can be set to inject controllable reactive power to condition the system. This also implies the need for a broader use of solid-state power electronics into the electrical system.

Distributed Energy

A primary driver for the smart grid is the decentralization of energy generation. Moving from a traditional vertical utility, where generation is centralized, to a largely decentralized generation network is a primary driver for the smart grid.

Distributed generation (DG) consists largely on alternative energy sources, including photovoltaic (PV), wind, biogas, biomass, fuel cells, combined heat and power (CHP), and geothermal. Other sources such as concentrated solar, tidal and wave are also in research and pilot phases. The benefits of utilizing DG includes locating generating sources close to demand, thus minimizing line losses, supporting clean and renewable energy sources, relieving distribution and transmission system congestion, and enabling customers to own generation and profit from selling excess power back into the grid.

However, distributed generation only paints half the picture. The majority of alternative energies are intermittent in nature, due to their dependency on intermittent sources of “fuel”, such as solar and wind, and thus cannot ensure consistent levels of supply. This poses an enormous challenge with matching energy supply and demand, as well in sizing the supporting distribution network. The greatest opportunity to mitigate these challenges lies in the use of distributed storage (DS). Storage options include large scale battery storage (e.g. sodium sulphur), capacitors, pumped water, flywheels, compressed air, thermal, hydrogen, superconducting magnetic energy storage (SMES), and batteries in electric/plug-in hybrid electric vehicles. The use of storage can buffer variations in intermittent supply and demand, significantly improving supply dependency and predictability, as well as reducing the need to curtail and redirect load, or require the development of additional fossil generation as back-up. Combining distributed generation and distributed storage, we get distributed energy.

Further mechanisms can be in place to mitigate the intermittency of alternative sources. This includes accurate generation and load forecasting, controllable demand response, and intelligent switching to direct the flow of energy.

A further challenge to the successful operation of a distributed network is its design and operation. The electric distribution system was designed for unidirectional power flow from the transmission transfer stations. Hence, its line capacities as well as protection system – which are critical towards the safe and secure operation of the grid – will fail under a high penetration of distributed generation. Moreover, distributed generation also have the potential of being “islanded” from the main grid, where they are disconnected from the grid yet continues to generate into a local area. This can pose significant safety and operational risks. To mitigate this will require advances in distribution system analytics (e.g. simulation software), infrastructure upgrades, adaptive protection devices and control schemes. Utilities will likely have to take a phased approach towards a high penetration of DG as solutions are made available and they gain experience into understanding the operation of a fully decentralized network. Research through partnerships with universities and national labs will also drive advances in the knowledge base.

Combining distributed generation, storage, and design and operational advancements, we have an intelligent distributed grid – a decentralized, efficient, clean, network that accommodates a large variety of energy generation and storage options.

Advanced Communications

In order for smart grid to become a network of intelligence, communication systems must be present to serve as the “glue” to connect all sources of intelligence together. In society, communications are critical to exchange ideas, build relationships, and empower actions. This has proven to be true from the phenomenal success of the Internet, where billions of people are interconnected in a fast, secure, and reliable network. Communications will serve a similar purpose for an integrated operation of the smart grid.

The characteristics of a communications network has been outlined in the previous section – open standards, interoperable, two-way, high bandwidth, and low latency networks. To make it all work together, devices have to be plug-and-play to simplify process. This is enabled by standardization. It is recognized that viable plug-and-play of devices, applications, etc., will require a significant effort, and openness and interoperability are key to achieving it.

Many network solutions are available, such as radio, microwave, satellite, fibre optics, cable, power line carrier/broadband over power line, telephone lines, cellular, and much more to come. However, experience tells us that there is not one, single medium that will cover all forms of communications. There are pros and cons to each, and suitable for various operations in the network. Even the Internet is connected through a vast array of communications technologies and topologies. The future will likely be a hybrid of various solutions, each implemented in its most suitable area. The key is interoperability amongst the various technologies and systems.

Intelligent Processes and Applications

The smart grid will consist of both decentralized and centralized processing. While intelligent components and advanced power flow control are supported by distributed intelligence throughout the grid, network and customer data will likely be backhauled to the distribution utility, where centralized processes and applications will translate them into information, knowledge, and actions.

Process and applications are what converts from a "smart distribution grid" into a "smart utility". They include:

- Robust business processes in planning, design, operation, and construction. Processes will govern the success of data detection, collection, transmission, analysis, and interpretation for decision making and deriving actions.
- Back office applications, such as customer information systems (CIS), outage management systems (OMS), distribution management systems (DMS), geographical information systems (GIS), enterprise resource planning (ERP), meter data management (MDM), and many more.
- Integration layers to connect back office applications, such as business intelligence (BI), enterprise data warehouse (EDW), service oriented architecture (SOA), and enterprise service busses (ESB).
- "Defence in depth" (DOD) security built into every process and application, coordinating with security mechanisms throughout the field and at the customer's premise, architected and implemented from the enterprise level.

2.3 TORONTO HYDRO'S INVOLVEMENT IN THE SMART GRID

Toronto Hydro has excelled and demonstrated leadership in developing a firm foundation for the smart grid. It has an extensive portfolio of smart grid building blocks, as illustrated in Figure 2. Toronto's smart grid will expand from this extensive portfolio of building blocks. While individual building blocks will continue to develop and mature, integration and security efforts have already begun. The smart grid will continue to discover new potentials of integrating systems and services for added benefits.

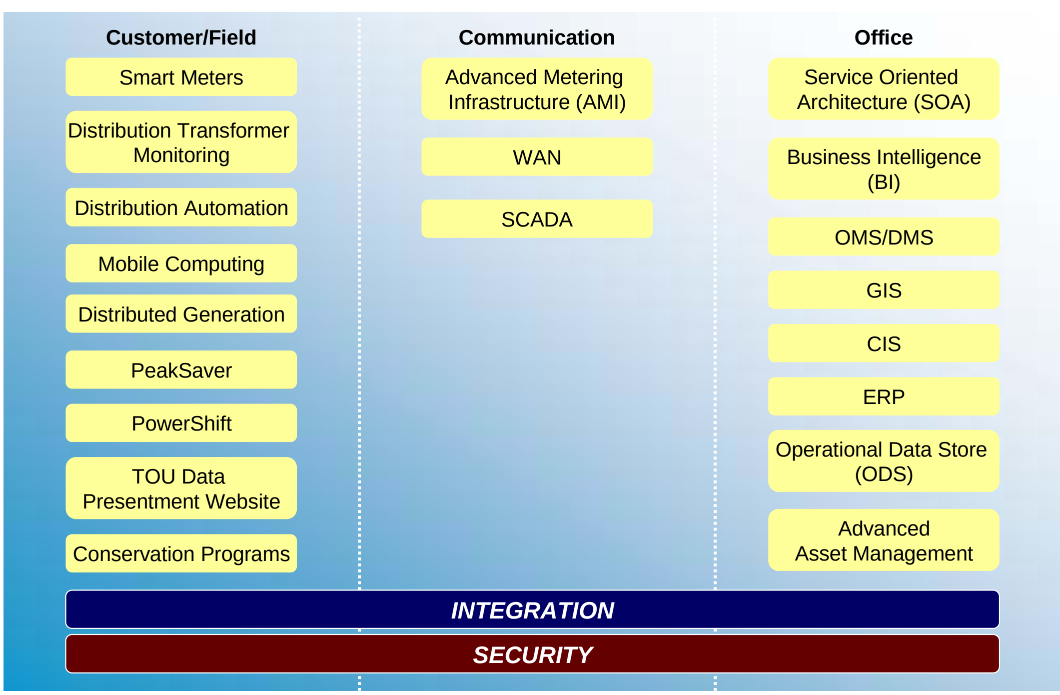

Figure 2: Toronto Hydro's current Smart Grid portfolio

Table 3 highlights several key initiatives that Toronto Hydro has undertaken that establish a firm foundation for the development of a smart grid.

TABLE 3: HIGHLIGHTS FROM TORONTO HYDRO'S SMART GRID PORTFOLIO

Building Block	Function	Highlights
Advanced Metering Infrastructure (AMI)	Network of sensors at every customer point. Utilities can gain unprecedented understanding of what the customer is experiencing.	• Over 567,000 installed, 80% done • Reading over 402,000 meters daily • By 2010 all customers will have a smart meter
Customer Web Portal	Web interface with the customer for providing information and services.	• Information to customers enables conservation and cost savings. • Allows customers to compare their bill under fixed prices and TOU rates. • A computerized "BOT" interacts with the customer in different ways. • Web self-servicing strategy
Conservation and Demand Management (CDM)	Reduce energy use and free up congestion in the infrastructure. "Negawatts" instead of megawatts.	• 1,150,000 compact florescent lamps distributed since initiation. 77,620 more to be distributed in 2009. • 26,446 inefficient room air conditions retired. 4,000 more to be retired in 2009. • Over 48,000 peaksavers, equating to 50MW of dispatchable load. • 326 PowerShift customers combine peaksaver with TOU • Summer Savings provides 10% credit reward for 140,000 residential and commercial customers who reduce their electricity usage more than 10%. 88,000MWh and 83MW reduced in 2007. • Business Incentive Program (BIP) provides incentive for businesses to install energy efficient equipment.
Distributed Generation	Enable cleaner forms of electricity generation, and generating close to the load for reducing losses.	• Over 89MW of distributed generation • Studies of the integration of DG into Toronto Hydro's electric system
Distribution Automation	Providing visibility and control throughout the system.	• Over 400 intelligent switches, "self-healing" ready for automatic fault detection, isolation, and restoration. • Transformer smart meter pilot monitors the loads on transformers. Enables loss detection and better management of transformer assets.

Enterprise Applications	Software and database systems to collect, clean, filter, interpret, and display data and information to people and other systems.	• Extensive portfolio of enterprise applications – outage management system (OMS), distribution management system (DMS), geographical information system (GIS: "GEAR"), customer information system (CIS: "CC&B"), etc. • Service Oriented Architecture (SOA) and Business Intelligence (BI) in progress

2.4 ILLUSTRATING THE VISION: DAY IN THE LIFE OF A FUTURE CUSTOMER

A smart grid must be developed around a vision of what the electric utility's service to its customer will need to be. Moreover, through enabling people, processes, and technologies, a smart grid must deliver the end benefits back to the customer, whether that is in improved services, reduced costs, or reduced impact to the environment.

In September 2008, Toronto Hydro co-sponsored a video illustrating the life of a future customer in the smart grid, created by a joint group of utilities represented in the Customer Care Research Consortium (CCRC). It illustrates how customers can interact with the utility in the year 2015. The video is divided in to six vignettes, and Table 4 lists the initiatives that are required to realize each of the vignettes.

TABLE 4: HIGHLIGHTS OF TORONTO HYDRO'S SMART GRID PORTFOLIO

Vignette Description	Services Required
Reducing Energy Usage	• Smart thermostat showing the level of energy consumption with a glowing dot, as well as the price of electricity • Utility web portal, allow viewing and control of smart appliances • Home energy management system • LED (light emitting diode) lighting • Smart appliances that responds to the time of usage, with an online utility calculator that computes the rate of return • Home area network (HAN) to enable communication between smart thermostats, home energy management system, and smart appliances
Managing Energy Usage	• Utility web portal that allows viewing of historical and projected energy usage, and match with monthly budget • Utility sends alert when monthly budget is to be exceeded, and suggests methods of meeting monthly budget • Web portal allows customers to change payment plan from bimonthly, monthly, biweekly, and weekly • Demand response on air conditioners, yet allows customer overrides for extra comfort

	• Online customer service representative
Technology and Self Generation	• Plug-in hybrid vehicle charging dock in the garage • Solar panels on roof, export power into the grid. The customer can choose to donate a certain portion of its energy output to a nearby senior's home • Energy management system on computer • An orb that changes color according to the energy consumed/supplied. Red indicates net consumption, green indicates net generation • Customized billing reports
New Customer Connection	• Smart appliances • Home area network that communicates with the utility network • Master controller for control of smart appliances, and serves as communications portal with the utility • Configuration of the smart home through asking simple questions to the customer • Option to purchase power from green generation sources • Option for utility to optimize usage of certain appliances to minimize energy bill or to environmental impact
Providing Financial Assistance	• Energy forecasts and matching with monthly budget, to avoid unexpected costs on the customer's bill at the end of the month • A gaming console that also serves as a home energy management system, with a rebate available from the utility • Online tutorial on how to use her new gaming console/home energy management system • Financial service agents
Responding to a Power Outage	• Utility representative notifies the customer on the customer's mobile device on the outage, what's happening behind the scene, and how long the outage will last • Self-healing smart grid pinpoints the outage, and reroutes electricity back to customers • Utility program enables customer to gain information on the outage status of other family members as well

What is the Customer's Vision of the Future Utility?

In December 2008, the Customer Care Research Consortium conducted two focused group research projects in the Washington DC area, to understand their expectations of the future utility and study their responses to this smart grid video.

When participants were asked about their expectations of the electric utility in the year 2015, their general responses include:

- More renewable energies. Solar and wind should be prevalent and cheaper
- Smarter infrastructure, in terms of smart meters, in-home smart appliances, and more efficient grids
- Rates must be reasonable
- Intelligent communications via text message, email, etc.
- Online tools to manage energy usage
- Rewards for conserving

Following this, the smart grid video was shown to the focused groups to assess their responses. Though they value the specific services shown such as in-home displays and outage notification, they were expecting the utility to have offered these services by now, as the technologies are already readily available and commonly used in other industries. They also demonstrated an overall scepticism and cynicism towards the costs of implementation and the utility's ability to deliver this vision.

Introducing behavioural science into the focus group research, psychologist and social research scientist John Marshall Roberts then applied an established value-based framework, based on the works of psychologist Claire W. Graves, to understand the customers' responses. It was found that though the customers share the same vision of the future as the utility, the services and communication messages from their electricity providers must relate to the core values of its customers, such as reliability, cost, transparency, financial aid to the poor, and environmental impact. By understanding its customer demographics, thus their values, the utility will be able to provide solutions, direct messages, and empower action to realize this common vision of the future.

3 THE CASE FOR CHANGE

The vision of smart grid is based on the realities that the electricity industry is facing today. Utilities must respond to these realities to continue providing its services for its customers, the society, and the environment. At a high level, the smart grid focuses on an integration of current strategies to fulfill environmental plans, address energy security concerns, and meet customer expectations. The message is very clear: it is a time of change.

3.1 DRIVERS FOR CHANGE

The Ontario Green Energy Act (GEA)

Around the world, policymakers are responding to environmental changes with new energy policies and legislation. The Green Energy and Green Economy Act (short titled "Green Energy Act") was introduced into legislation as Bill 150 in February of 2009. This is part of Ontario's plan to become a leader in renewable energy and green economy in North America.

Once passed, it would:

- "Spark growths in clean and renewable sources of energy such as wind, solar, hydro, biomass, and biogas in Ontario
- Create the potential for savings and better managed household energy expenditures through a series of conservation measures
- Create 50,000 jobs for Ontarians in its first three years"[4]

"There exists today a global race to establish the policies, attract the investment and build the foundation for the green economy that is sure to sustain future prosperity and progress. It is a race Ontario is determined to win. This proposed legislation would help Ontario become the preferred destination for green jobs, green investment and green energy."

"Our ambition is to increase the standards of living and quality of life for all Ontario's families. That is best achieved by creating the conditions for green economic growth."

George Smitherman, Deputy Premier and Minister of Energy and Infrastructure

Highlights of the act as it relates to the role of the distribution company include:

- Definitions for "smart grid" and "renewable energy source"
- Obligation for transmitters and distributors to provide priority connection access to their systems, for renewable energy generation facilities that meet technical, economic and other regulatory requirements

[4] http://www.mei.gov.on.ca/english/energy/gea/

- Feed-in tariff program that guarantees specific rates for energy generated from renewable energy sources
- One-stop streamlined approvals process, providing service guarantees for renewable projects
- Provide municipalities with the ability to generate up to 10 megawatts of electricity
- Creation of a renewable energy co-operative, restricted to generating and selling electricity from renewable energy sources
- Streamlining of municipal approvals for renewable energy generation facilities, including the elimination of any requirement to comply with a municipal official plan or zoning by-law
- Permit a distributor to own a renewable energy generation facility that does not exceed 10 megawatts (or such other capacity prescribed by regulations), a generation facility that uses technology that produced power and thermal energy from a single source, or an energy storage facility
- Local Distribution Companies (LDCs) will be required to prepare plans and seek the Board's approval for the expansion or reinforcement of its distribution system for the connection of renewable energy generation facilities and for the development and implementation of the smart grid
- Amendments to the Ontario Energy Board Act, 1998, requiring the Board to take steps as specified in relation to the "establishment, implementation promotion" of a smart grid

The Green Energy Act has the potential of creating the single largest transformation of the electric industry since it was first constructed. To respond to this call for action, a smart grid must be created, overlaying the power delivery infrastructure with a high speed, two way, robust, and secure information, communications, and intelligence network. The customers will further have to be empowered with information and tools to participate in conservation and renewable energy initiatives.

"In 1999, the German government made available low-interest loans for renewable electricity generation equipment. The following year, they put in place the Renewable Energy Sources Act (EEG), which allowed homeowners and farmers to connect their power systems to the grid and provided them a fair price for their surplus electricity. While this created some additional interest, an amendment to the EEG in 2004 boosted power sell-back prices by 25 percent, causing investment to skyrocket. Between 1999 and 2003, the number of residential installations of photovoltaic power systems grew steadily at a CAGR of 88 percent, but in 2004, installations shot up by 233 percent.

In 2006, Germans invested more than US$10 billion in new sources of renewable energy, setting a world record. Germany now operates more wind-powered generation, more solar systems and more biogas plants than any other nation worldwide."

IBM Global Business Services, Plugging in the Consumer

City of Toronto's Climate Change Plan

The City of Toronto has also committed to environmental leadership and creating a sustainable future for Torontonians through its Climate Change, Clean Air, and Sustainable Energy Action Plan. It is the City's belief that "in a sustainable city, a clean and healthy environment goes hand-in-hand with strong community engagement, a thriving economy and access to opportunity for all residents"[5].

A number of key initiatives are identified as a part of the plan, including:

- Becoming the renewable energy capital of Canada
- Building a sustainable transportation system
- Green economic sector development
- Water efficiency plan
- 70% waste solid diversion plan
- Doubling the tree canopy

> **"During our public engagement for the Climate Change, Clean Air and Sustainable Energy Action Plan we heard a very clear message: the residents of the City of Toronto want action and they want the knowledge and support needed to make real changes in their homes, businesses and neighbourhoods"**
>
> *Climate Change, Clean Air and Sustainable Energy Action Plan: Moving from Framework to Action, Phase 1, City of Toronto*

The reduction target for greenhouse gas (GHG) emissions, from 1990 levels of approximately 22 million tonnes per year are:

- 6% by 2012 (Kyoto target)
- 30% by 2020
- 80% by 2050

The reduction target for locally generated smog causing pollutants is 20%, from 2004 levels by 2012.

Similar to the Ontario Green Energy Act, it must be emphasized that a smart grid is essential to realize a greener future. The present system with its technologies does not have the intelligence required to achieve such benefits. A smart grid will enable a sustainable future by:

- Enabling the safe and efficient connection of a large number of renewable and clean generation sources
- Identifying the location of and mitigating system losses, including line losses and power diversions
- Energy storage to offset peak power and balance intermittent supply and demand
- Supporting an electrified transportation system

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[5] City of Toronto, "Climate Change, Clean Air and Sustainable Energy Action Plan: Moving from Framework to Action," Available at: http://www.toronto.ca/changeisintheair/pdf/clean_air_action_plan.pdf

- Providing customers with the information and tools to manage and conserve electricity

Electrification of Transportation

The electrification of transportation represents one of the greatest shifts in the transportation industry following the invention of the internal combustion engine. Governments and customers are looking upon a new generation of plug in electric/hybrid electric vehicles as the solution to reduce dependency on foreign oil, reduce impact to the environment and provide economic stimulus.

According to the US Department of Energy, it is estimated that US power plants may meet the power requirements of 73% of the nation's light vehicles if they were replaced by plug-ins charging at off-peak times. This means a reduction of oil consumption by 6.2 million barrels per day and the elimination of 52% current imports[6].

Nevertheless, transitioning to a "plugged in" electric transportation infrastructure presents a vast challenge for both the electricity and automobile industries. Challenges include:

- Need for a standardize plug for charging
- Metering and standardized communications required for cross-geographical billing
- Impacts to system power quality as vehicles charge or export back to the grid
- Stress to the grid as vehicles charge during non-peak hours
- Challenges in predicting demand

Intelligence is essential for the grid to accommodate a high penetration of electrified vehicles:

- Smart chargers and enhanced battery storage, with two-way communications between to vehicle and the grid for sensing pricing and other signals
- Utility systems to coordinate variable supply and demand
- Power quality conditioners to enable a large penetration of plugged in vehicles
- Potential for utilizing vehicle's storage devices to export power back into the grid ("vehicle-to-grid", or V2G), especially during critical peak periods

In addition to the automobile industry, other areas of the transportation section are also becoming increasingly electrified. With the TransitCity plan, the Toronto Transit Commission (TTC) is determined to expand its light rail:

> ***The Toronto Transit City Light Rail Plan is an exciting initiative that will revolutionize transit and transportation across Toronto. Its far-reaching lines will revitalize neighbourhoods, spur economic growth and clean the air we breathe.***

[6] US Department of Energy, "The Smart Grid: An Introduction," Available at: http://www.oe.energy.gov/DocumentsandMedia/DOE_SG_Book_Single_Pages.pdf

Seven new Light Rail Transit (LRT) lines will bring reliable, fast, quiet and comfortable transit service to many Toronto neighbourhoods. Transit City has been strongly endorsed by the TTC, the City of Toronto, and Metrolinx, the regional transportation agency. The Province of Ontario has announced funding for the construction of the lines and they are incorporated into the Regional Transportation Plan recently proposed by Metrolinx.[7]

Furthermore, the Government of Ontario has announced the Move2020 plan in June 2007, committing to launch a $17.5 billion rapid transit action plan for the Greater Toronto Area and Hamilton, tackling gridlock, creating 175,000 jobs, and strengthening the economy. In this plan, the government recommended building 902 kilometres of new and improved rapid transit, as well as electrifying the GO Lakeshore line.[8]

Such vast electrification of public transit will imply further congestion of the electric infrastructure, demanding generation, transmission and distribution upgrades. Intelligence in the system is needed to provide effective execution of infrastructure upgrades and management of assets, and to maintain a reliable electric network. To reduce the need for long distance electricity transmission and distribution, providing generation close to demand through a distributed generation architecture will ensure that losses and environmental impact are kept to a minimum when transportation switches from fossil-fuel to electricity as a fuel.

Energy Security

Constructed predominantly in the early to mid 1900's, the electric power system has been recognized as one of the most significant engineering developments of the 20th century.

But this complex infrastructure is old and continues to age at a fast pace. Significant portions of the distribution system have reached advanced deterioration and end of life stages, and it is becoming increasing difficult to keep up with the needs for capital investment. An aging infrastructure represents higher operational and maintenance costs and more importantly, lower reliability and power quality. Moreover, the increased number of major blackouts the industry has begun to raise attention on electric infrastructure investments.

Toronto is a growing city with a growing demand for electricity. As the demands on electricity grow it stresses on the capacity of grid elements and increases risks with decreased operating margins and reduced contingencies. Siting new equipment is also extremely difficult as overhead and underground land uses are nearly at full occupancy. There is an urgent need to enable customer participation in conservation and time of use

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7 http://www3.ttc.ca/About_the_TTC/Projects_and_initiatives/Transit_city/index.jsp

8 http://www.premier.gov.on.ca/news/Product.asp?ProductID=1383

efforts, to offset or delay the need to build and site new infrastructure, while the utility optimizes the distribution of electricity and use of the assets.

The price of electricity is influenced by supply and demand. However, once electricity is generated it must be consumed, as the system is limited in its ability to store excess capacity . Hence generation, transmission and distribution capacities have to be scaled to accommodate the highest demand, and a significant portion of system capacities are merely utilized in a few days of the year. While the customer pays fixed electricity rates, the true costs of electricity in the market has become very volatile as consumptions are not well controlled.

The traditional vertically integrated electric system is further not designed for efficient operation, especially during peak periods. Significant line losses and lack of detection of power diversions imply that a large majority of energy generated is wasted and never delivered to the end customer. If the grid were just 5% more efficient, the energy savings would equate to permanently eliminating the fuel and greenhouse gas emissions from 53 million cars[9]. In addition to high losses, the use of spinning reserves to meet peak demands implies further impact to the environment.

Moreover, with the advent of the digital and connected era, the grid is becoming more susceptible to cyber security risks. The installation of large numbers of communicating devices also increases the number of access points and thus making the grid more vulnerable. The threat of terrorism, copper theft, and vandalism present a further risk for the grid. Reduction of system vulnerability and prompt identification of threats is essential.

In addition to infrastructure challenges, the electricity sector is facing high retirement rates, exposing the organization to significant risks in this time of change in renewing and upgrading the infrastructure. It is expected that the industry will need to incur additional expenditures to replace and train skilled workforces, requiring both specialists in traditional and new fields, as well as generalists with diverse skills sets. Currently it requires approximately five years to train trades employees on the job.

These risks, including aging infrastructure, congestion, price volatility, system losses, security risks, and need for workforce renewal compound to create a future of uncertainty. This results in high unknowns for the future including future investment requirements. Nevertheless, as Peter Drucker writes, “the best way to predict the future is to create it”. With strategic investments, embedding intelligence into the system, pursing new technologies such as energy storage, empowering customers for energy management and more, the future can become more certain, and utilities will be able to mitigate the risks associated with this changing industry.

[9] US Department of Energy, “The Smart Grid: An Introduction,” Available at: http://www.oe.energy.gov/DocumentsandMedia/DOE_SG_Book_Single_Pages.pdf

Customer Expectations in a Digital Era

The expectations of customers have changed dramatically in the digital era. Customers now recognize community values and environmental actions on par with traditional values like customer service and reliability. It is well understood that environmental problems are highly associated with energy problems. Customers want to be more aware of their environment footprint in both their electricity and transportation uses. They are interested in renewable energy options and more familiar with the environmental practices of energy providers. The customer of today wants to have a more active role on how to control their electricity use to mitigate environmental damage.

Corporations outside the utility industry are also very aware of their environmental impact and implementing measures to reduce their footprint. This is reflected in the recent applications of corporate responsibility reports and will be accelerated once a carbon cap and trade system is in place.

In times of rising energy costs, there is further a high motivation for conservation and consumption management through greater awareness and better technologies. For examples, consumers will choose to use power at off-peak times and be rewarded for it with a lower rate. They will be able to find out hour by hour the units of power they've used, what they cost, and how to use less without compromising their quality of life.

The coming of the digital age has further influenced consumers' views, behaviours and expectations. In light of these changes utilities will need a radical shift. Today, the electricity system is primarily a vehicle for moving electricity from the generation source to the costumer. In order to respond to new customer demands utilities should engage a new era of technology and telecommunications.

As described in Section 2.2, the vision is to move towards a participatory network, with the utilities and customers sharing responsibilities and benefits, to achieve core objectives such as maintaining quality of life, reducing costs, and minimizing environmental impact.

Utilities must be prepared to adapt to these new trends and provide new services. The challenge is to connect its operations with customer experience. The smart grid will allow end-users of electricity to ensure their involvement in deciding how and when they use energy. With the application of new technologies the grid will enable two-way flows of electricity and information, empowering them with control to make informed energy choices to benefit them, the infrastructure, and the environment.

3.2 THE VALUE PROPOSITION

Toronto Hydro's smart grid is the plug that connects environmentally mindful consumers to the grid in a digital era

The smart grid is an essential component to carry the traditional electric infrastructure in the direction that society would like to go in the 21st century. This section explores the benefits and challenges that the smart grid will bring.

Customer Benefits

The smart grid connects consumers to the grid not only to improve the customer experience but also to excel their participation in the grid:

- Access to timely information to make informed decisions on their energy use, such as interval usage data, price, fuel mix, carbon footprint, and utility offers. Enables awareness of energy use and its relation to carbon footprint.
- Greater control through tools and devices to conserve electricity and reduce costs, such as energy efficient appliances, high efficiency lighting, promotional pricing models, home automation, demand response units, energy audits, and insulation upgrades. Automation and configuration allow customers to set preferences according to their lifestyles.
- Manage their electricity usage with an energy budget dashboard, including historical usage, projections, as well as alerts and alarms to notify excessive usage.
- New modes of communication such as in-home energy displays, web portals, smart thermostats, email, media players, mobile phones, and online call centre.
- Provide better experience with the utility, such as through self servicing models which enable customers to manage their accounts online.
- Set preferences over their billing, such as information displayed, billing cycles, or prepaid plans.
- Improvements in grid reliability and power quality through monitoring and controls.
- Receive outage notifications from the utility, cause of outage, immediate actions, time to restoration, tips on what to do, and restoration notification.
- Opportunities to generate and sell electricity back into the grid.
- Mechanisms to contribute towards the environment, such as signals and programs to limit the use of coal generation, decide on a preferred fuel mix, and renewable self generation.
- Support the connection and billing management of full electric or plug-in hybrid electric vehicles.

Social and Economic Benefits

The smart grid supports social and economic growth by:

- Job creation through the design, construction, operation, and support of a renewed infrastructure. For example, the Green Energy Act forecasts the creation of 50,000 high paying jobs in Ontario in the first three years, while Ontario's Move2020 plan estimates a further 175,000 jobs in the expansion of the transportation infrastructure, largely supported by the electric system.
- Stir economical growth through global investments, ensuring security of supply, job creation, and increasing competitiveness by enabling the national economy to lead in the development of renewal energy solutions.
- Opportunities for the enhanced coordination of utilities and efficiencies in the development of shared services, such as in public telecommunications bandwidth.
- Increase in public safety and quality of life by investing in an aging infrastructure, supporting safe operation of distributed generation, and creating an environmentally sustainable future.
- Promoting cleaner air, better water, and fewer wastes for generations to come, such as through the use of renewable energies, conservation, and electric vehicles.
- Reduce dependence on oil and encourage the use of alternative fuels.
- Commercialization of energy efficiency, renewable energies, and electric vehicles will bring opportunities for increased economic activities.
- Relieving gridlock through expansion of electrified public transit systems.

Environmental Benefits

The smart grid can deliver and realize enormous environmental benefits:

- Promote use of energy generation and conservation for residential and commercial buildings will contribute to the reduction of the carbon footprint as well as the reduction in costs and energy consumption.
- Reduction in the generation of CO_2 and pollutants into the environment with the displacement of centralized plants with distributed generation, offering cleaner and renewable fuel sources and minimizing line loss. Peak demand reduction and energy storage also reduce the need for peaking power plants and spinning reserves.
- Design and construction of buildings will meet environmental regulations as well as include technological breakthroughs for energy renewal and conservation.
- Having alternative renewable sources of electricity like solar, wind and geothermal will lessen the necessity for power generation plants of the 21st century and therefore, reducing environmental impact and the risks associated with global warming.

Utility Benefits

The smart grid enables utilities to meet the needs and demand of the electric infrastructure:

- Ensure reliability in the generation and distribution of electricity through the use of innovative technologies, such as outage management systems, power quality monitors, and automated switching.
- Provide “digital grade” power quality through monitors, analyzers, and conditioners.
- Ensure security of energy supply through conservation, infrastructure expansions, rerouting of power, loss reduction, and distributed generation.
- Improved equipment monitoring increases asset utilization and reduces operating margins.
- Operational improvements in monitoring, control, and mobile workforce support
- Provide intelligence and control capabilities to accommodate a high penetration of distributed generation and electrified vehicles.
- Allow deferral of infrastructure investments through distributed generation, storage, conservation, and peak demand reduction.
- Consideration to physical and cyber security will ensure that the grid is protected and resilient to attacks.

Challenges and Costs of Deployment

While the smart grid has significant potential to deliver value, it represents a significant endeavour. Research and development is needed to break through knowledge and technology barriers. Technology solutions will take time to develop, mature, and be ready for commercialization. Communication and engineering standards will need to converge.

Building Toronto Hydro’s smart grid will require a framework of intelligence, energy, communications, strategy, legislation, regulation, and stakeholders’ commitment. Business models should have a solid foundation for decision making to ensure ongoing commitment to innovation. A coordinated innovation effort will consist of a solid integration and synchronization of decentralized systems, processes and organizational structure. The workforce will require new competencies, while not drawing resources away in a time of renewal of aging infrastructure. Security measures must be put in place. Business processes, operating procedures, and work protection will have to incorporate the new paradigm of a smart grid.

Progressive and timely legislation and regulation will be instrumental towards its success. Disincentives from rates must be removed to recognize the benefits of conservation and energy efficiency, as well as accounting for socioeconomic and environmental factors.

Customer education and adoption of new technologies will further need to be assisted by retailers and service providers. Utilities will have to approach customers with transparency and address their specific yet evolving needs.

The costs and time required, as well as the benefits attained, will depend on the scope and pace of implementation, technology trends, and customer acceptance, and is thus not straightforward to quantify. Costs and benefits are typically shared amongst a wide mix of projects rather than in isolation. Investments are made to account for future requirements, and benefits often extend into socioeconomic and environmental contexts and to improve customer experience.

Careful investments and guiding strategies can be utilized to mitigate the risks of initial deployments and ensure that early benefits are attained. Given that investments in the Advanced Metering Infrastructure (AMI) have been mandated by the government, and that some of the building blocks for the smart grid are already in progress and maturing within Toronto Hydro, it is expected that additional costs for smart grid deployment will be incremental spending to accelerate maturing of in-progress building blocks, implementation of new smart grid solutions, and in integrating various programs/solutions.

The Ontario Smart Grid Forum report states that "overcoming these challenges will require innovation, investment, creativity and hard work, but if Ontario is to realize a sustainable future and continue to grow and prosper, the transformation of its electricity infrastructure is essential."

Toronto Hydro is responding to the call for action to create a better future for the environment, customers, and the electricity infrastructure. Considering the solid foundation that has already been developed and the commitment towards this endeavour, Toronto Hydro is determined to thrive in its smart grid deployment.

4 VISION, MISSION, OBJECTIVES AND STRATEGIC PRINCIPLES

A clear vision of the smart grid has been defined and illustrated. This vision has been grounded upon the central belief that it will provide prosperity and benefits to the people of Toronto, the electric infrastructure, and the environment. Yet a vision must lead to actions.

How well the utility navigates through this perfect storm will depend on how it strategically applies its resources, competencies, and capabilities to accomplish its vision, leading to real and tangible results. This chapter will lay the foundation for this voyage, including:

- Vision and mission statements to identify where we must go and what we must do
- Specific objectives to define what we want to achieve
- Strategic principles to guide our scope, priorities, and how to achieve our objectives

4.1 VISION AND MISSION

The vision statement reflects the essence of Toronto Hydro's goal towards a smart grid and a Smart Utility:

Vision: An intelligent, continually innovative electricity network

This vision illustrates the smart grid as an electricity network with two traits. The first is *intelligence*, referring to the "smartness" of the grid, including self-healing, robustness, fast, reliable, and having optimized solutions. The second trait is a *continual innovation*, defining the smart grid as a paradigm rather than a technology, a direction rather than project. The core of this direction is innovation, where new solutions and methods are strategically applied to the electric system and its services. It's a continuously advancing utility, keeping up with the needs of its customers and applying new technologies and methods in its solutions.

In other words, this vision statement describes the paradigm of *smart grid as innovation through applied intelligence.*

The smart grid mission statement describes the task to accomplish our vision:

Mission: Modernize to deliver value in meeting customer needs and expectations of the 21st century

Thus the mission is to modernize. This includes modernizing the infrastructure, communications, and even processes, culture, and the services it provides to customers. This modernization is necessary in order to deliver value in the 21st century, including value to our customers, shareholders, staff, and the environment. Modernization is the first step towards innovation.

4.2 OBJECTIVES

The Case for Change in developing the smart grid system has outlined three key drivers for smart grid. It is also through these drivers that our objectives are set.

Objective #1: Climate Protection and Sustainable Energy

As an energy company, Toronto Hydro has the social responsibility to become an organization that values climate protection and environmental sustainability. This will require a close partnership with our customers, the governments, as well as other agencies and organizations to make this a priority.

In particular, Toronto Hydro can have a substantial contribution meeting the following government targets in the area of climate protection:

City of Toronto's Climate Change, Clean Air, and Sustainable Energy Action Plan (the Climate Plan) of July 2007

- 6% greenhouse gas (GHG) and 20% smog reduction by 2012
- 30% GHG reduction by 2020
- 80% GHG reduction by 2050

Federal Government's targets

- Kyoto Protocol targets: reduce CO_2 emissions by 6% below 1990 levels between 2008-2012
- Upcoming carbon cap and trade system

Further targets are expected to be set by the Ontario government as a result of the Green Energy Act.

For Toronto Hydro to effectively meet these targets and become environmentally sustainable, we need to achieve the following:

1. Targeted reduction of environmental footprint, working towards a zero carbon, zero waste organization by closely monitoring, tracking, and controlling our environmental footprint and helping our customers manage their environmental footprint

2. An infrastructure that accommodates a variety and high penetration of distributed generation and storage options.
3. Provide customers with programs and streamlined processes for the connection of renewables, clean generation, and conservation efforts.
4. An infrastructure that supports the reliable connection of microgrids, community energy, and virtual power plants in the Toronto Hydro system.
5. Support an electrified transportation infrastructure, including full and plug-in electric hybrid vehicles, subway systems, and electric trains.

Objective #2: Energy Security

It is the mandate of Toronto Hydro to deliver electricity to our customers that is safe, reliable, and efficient. As the infrastructure ages and approaches the end of its useful life, utilities must sustain the operation of this infrastructure. At the same time, utilities are faced with new expectations from their customers and regulatory environments.

To achieve energy security, we need to:
1. Invest prudently in an aging infrastructure to manage risks and to provide high levels of reliability.
2. Provide the visibility and control throughout the network, working towards a self healing and fault anticipatory network, and connect high levels of distributed energy sources.
3. Monitor and manage power quality levels and its impact to customers.
4. Improve the efficiency and effectiveness of utility operations.
5. Incorporate Physical and cyber security measures.

Objective #3: Customer Satisfaction in the 21st Century

The smart grid opens up new and exciting opportunities for us to work together with our customers, who value trust, service excellence, transparency, performance, and reasonable rates. Customers also expect "digital grade" power quality and new modes of communication in the 21st century, comparable to the services they receive in the industries such as Telecom and Internet Service Providers. The utility must understand customer expectations, and provide information, tools, options, and controls to meet them.

To achieve customer satisfaction in the 21st century, we need to:
1. Provide timely information that empowers actions and improves experience with the utility, such as their environmental footprint, energy consumption management, outage and restoration notifications, costs and cost projections, budget constraints, utility programs.

2. Offer new forms of communications for customers to have timely access to utility information, such as web services, email notifications, text messages, online chat-rooms, blogs, and through in-home devices. Multilingual services are also required.
3. Enable energy management controls such as in-home displays, smart thermostats, and smart home appliances, with intuitive, user friendly interfaces.
4. Provide new forms of customer service models that suit their preferences, such as on-line self-services, voice recognition systems, changing billing payment periods, and prepayment options.
5. Offer advices on conservation and saving costs, reducing carbon footprint. Rewards for conserving. Allows integration of renewable energies and plug-in hybrid vehicles with simplified processes.
6. Potentially provide incentives and financial support to sustain reduced energy consumption and environmental footprint, especially for low income households.

4.3 STRATEGIC PRINCIPLES

Strategic principles are simple, understandable, actionable statements that reflect an organization's strategy to achieve a vision. It should empower stakeholders to move towards the smart grid vision. This section presents three strategic principles, developed based on industry needs, utility trends, and the strategic position that the organization decides to adopt to implement a smart grid.

Strategy #1: Harness innovation – throughout the grid

This strategy defines the action and breadth of Toronto Hydro's smart grid. As described in the vision and mission statements, the action for deploying a smart grid is in modernization, by harnessing innovation through applying intelligence in the system – intelligent people, intelligent business processes, and intelligent technologies.

Hence, in this strategy smart grid is defined not as a technology portfolio, but a paradigm of innovation, a continuous process of improving through innovating. It is about evolving and keeping abreast of advances in other industries, such as the information technology and telecom industries, and offering comparable services to customers. It is about being a "smart utility", and offering "smart energy".

This action is to be applied throughout the grid, creating an "end-to-end" smart grid. This means that the smart grid will have coverage throughout the electricity network:

- Applying smart grid inside the medium voltage distribution network
- Enabling and providing solutions beyond to the meter to assist customers in conserving, managing energy usage, and incorporating renewable energies

- Partnering with upstream transmission system and other distribution networks in global optimization

As one of the largest distribution utilities in Canada, and responsible for operating the electricity network in the mega-urban financial hub of the City of Toronto, Toronto Hydro is committed to develop an end-to-end smart grid.

Strategy #2: Explore synergies by integrating systems

The greatest value from a smart grid is not from the development of independent initiatives, but from the integration of its various technologies and services, and to maximize the use of available data and information. This strategy emphasizes that true innovation arises when synergies between various systems and services are explored. This is a *holistic* approach to smart grid, by focusing on integrating various building blocks to realize new values and services. The action to realize such synergies comes from the second half of the strategy – integrating systems:

- Between people to work collaboratively
- Between strategies and plans for alignment and leverage
- Between technologies for enhanced functionalities
- Between services for added value

Strategy #3: Develop an Innovation Support Structure

The true strength of this smart grid arises when innovation is accompanied by a support structure. It includes:

- Strategic planning to direct, guide, and focus efforts on constructive innovation, while filtering disruptive ones that don't show true value
- Business processes alignment and management
- Mechanisms to quickly turn trends into actions
- Measures to sustain innovation and avoid innovation fatigue
- Education and training of resources
- Customer, government, and regulatory engagement
- Technology support, such as bidirectional communications and power flow

4.4 ALIGNMENT WITH TORONTO HYDRO'S STRATEGIC BUSINESS PRIORITIES

Toronto Hydro has four business pillars. A smart grid will support and strengthen each of these pillars moving forward. These pillars include:

- Provide a safe and healthy work environment
- Modernize our utility
- Deliver superior customer service
- Maintain financial strength

Additionally, it has been the organization's priority to work closely with the City to help implement its Climate Change, Clean Air, and Sustainable Energy Action Plan (Climate Change Plan). A mapping of each of the smart grid objectives that have a direct relationship to these strategic business priorities are listed in Table 5.

TABLE 5: ALIGNMENT OF SMART GRID OBJECTIVE AREAS WITH STRATEGIC BUSINESS PRIORITIES

	Smart Grid Objective Areas	Health and Safety	Modernize Our Utility	Customer Satisfaction	Financial Strength	Climate Change
1	**Climate Protection and Sustainable Energy**					
1.1	Zero carbon, zero waste		✓			✓
1.2	Distributed generation and storage		✓	✓		✓
1.3	Streamlined process			✓		✓
1.4	Microgrids, community energy, and virtual power plants		✓	✓	✓	✓
1.5	Electrified transportation		✓	✓	✓	✓
2	**Energy Security**					
2.1	Invest in aging infrastructure	✓	✓	✓	✓	
2.2	Manage power quality		✓	✓	✓	
2.3	Visibility and control throughout	✓	✓		✓	✓
2.4	Improve utility operations	✓	✓		✓	
2.5	Physical and cyber security	✓	✓			
3	**Customer Satisfaction**					
3.1	Timely information		✓	✓		
3.2	New forms of communication		✓	✓		
3.3	Energy controls		✓	✓	✓	✓
3.4	New customer service models		✓	✓		
3.5	Advices from utility			✓		✓
3.6	Incentives and financial support			✓		✓

5 STRATEGIC ROADMAP

Toronto Hydro is committed to developing a smart grid. All drivers are pointing in the same direction, calling for a need to modernize. It's time to move forward. The role of this strategic roadmap is to serve as the tool that translates our vision, mission, objectives, and strategies into a set of actionable programs/projects. Illustrating the path to the future, the roadmap gives direction and foresight into what needs to be done (strategy #1), what to prepare for these initiatives, establishing long term needs, and aligning timelines. It further clarifies relationships and interdependencies for building synergies between programs (strategy #2), and enable us to lay down necessary foundations to support innovation early in the planning stage (strategy #3).

5.1 ROADMAP DEVELOPMENT PROCESS AND HIGHLIGHTS

The roadmap development process is outlined in Figure 4. From the drivers in the case for change, this translated into the vision and mission of the smart grid. This then is interpreted as a comprehensive list of objectives and the strategic principles for deployment. From that, a list of services were identified to achieve the mentioned smart grid objectives, with enabling technologies identified, and supported by necessary research and development efforts. This is then prioritized into 3 year, 3 to 10 year, and 10 to 25 year plans.

The following factors are considered when prioritizing the roadmap initiatives:

- Necessity to deliver on government policy
- Customer needs and expectations in the digital age
- Technology trends and readiness
- Ability to generate short term results
- Feasibility and capacity to execute, both financially and available skilled personnel

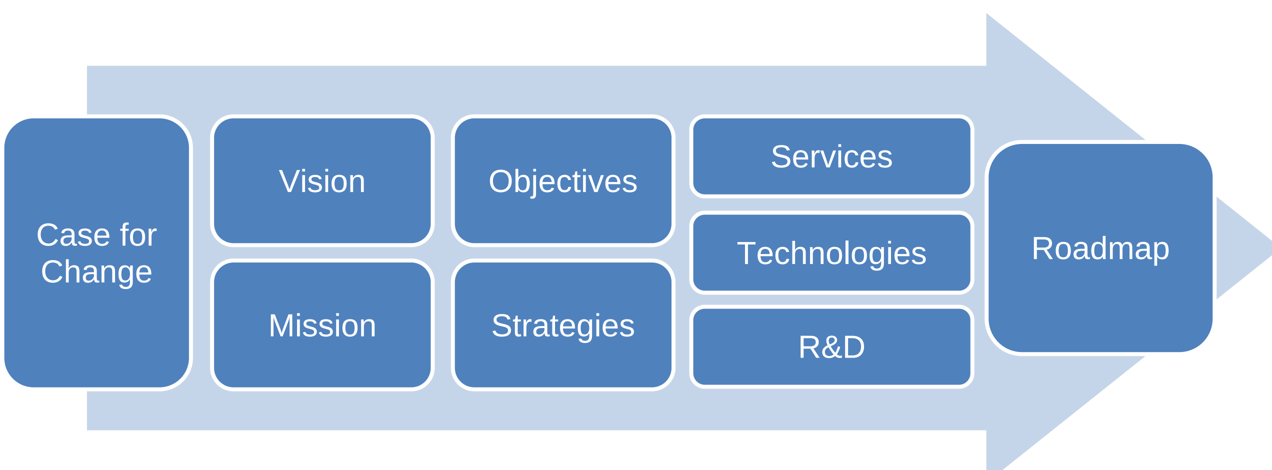

Figure 4: Roadmap development process

The following critical assumptions are also made:

- Government and regulatory support
- Workforce knowledge transfer
- Core business is maintained
- No disruptive game-changers

This roadmap can then be used to drill down on the requirements of individual initiatives, through models such as use cases.

Moreover, this is intended to be a living roadmap. While it has the potential to bring significant value to the infrastructure, society, and the environment, smart grid is not risk free. Many technologies and standards are still in their early stages of development, and not all will move into commercialization or reach a suitable price point for mass deployment. As seen in the later sections, this proposed roadmap attempts to recognize such risks and incorporate measures to ensure that its promises and value are realized. Nevertheless the roadmap will evolve with lessons learned from the initial stages of deployment, and as needs, technologies, and priorities change over time. What are needed are regular reviews, adequate research, innovative strategies, and mechanisms to quickly turn new trends into actions.

5.2 SMART GRID ROADMAP HIGHLIGHTS

Given the above process, a 25 year roadmap was developed for Toronto Hydro's smart grid deployment. Highlights of the roadmap are illustrated in Figure 5.

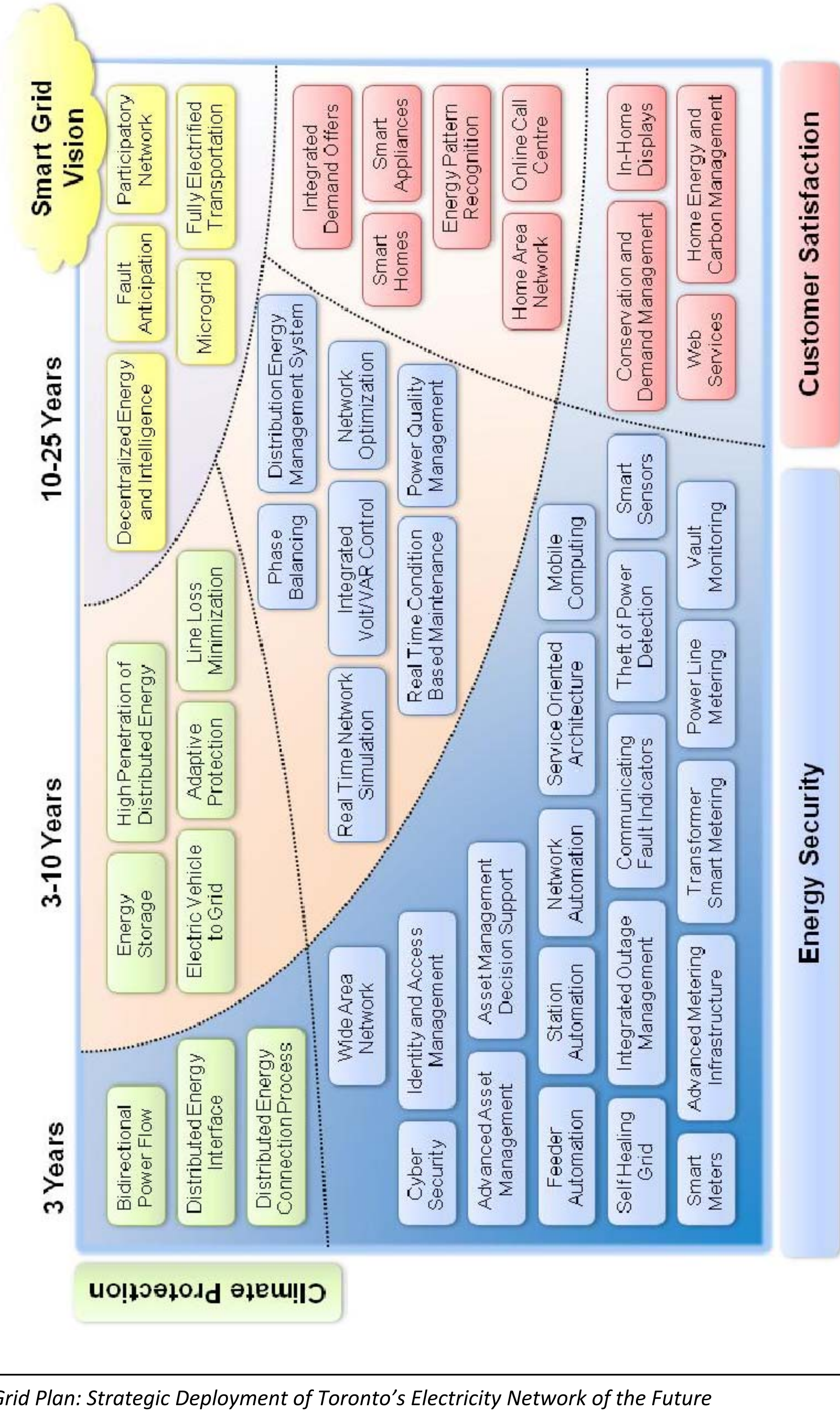

Figure 5: Highlights from Smart Grid Roadmap

5.3 3 YEAR PLAN: DEMONSTRATING TORONTO'S SMART GRID COMMUNITY

The first 3 years of the smart grid roadmap is to materialize the smart grid vision and strategy and translate into actions, through the establishment of *Toronto's Smart Community*.

The Smart Grid Community is a demonstration area where technologies can be tested, processes developed, customer acceptance understood, and operating procedures written. The innovation effort will begin, and all three strategic principles will be used to guide its implementation. Toronto Hydro's leadership and expertise will be leveraged to:

- Maturing existing smart grid building blocks
- Commit to and accelerate planned building blocks
- Integrating our building blocks to realize cross-functional services, shared costs, and added values

Functional strategies such as for communications, distribution equipments, and customer engagements will be developed to guide this effort. Opportunities to attract new workforces and partnerships will also be explored.

The size and scale of this demonstration is currently proposed to include 2 substations, 10 feeders, and approximately 25,000 customers. The location of this demonstration area as well as its detailed scope will be determined in a separate detailed plan. However, the following factors will be considered in determining the demonstration area:

- Reliability performance
- Feeder proximity
- System operational flexibility
- Smart grid devices installed
- Communications coverage
- Customer diversity

Expected benefits will be demonstrated and measured, and used to support potential full scale deployment. The goal is to generate short term wins, and validate the true value of smart grid. Additional opportunities and potentials will also be identified for further piloting. Results and lessons learned will be shared regularly in various forms of communication, such as white papers, presentations, and online content.

Initiatives that were selected as a part of this demonstration are characterized by relative certainty and value, typically utilizing established, proven technologies to demonstrate immediate value for the customer, society, and the environment. These projects are typically in progress and maturing at Toronto Hydro, or planned to commence in the next three years. The smart grid community will accelerate their maturity, and explore areas of integration to provide new services.

For more uncertain initiatives, it is expected that given the pace of industry adoption and effort into advancing smart grid technologies, in 3 years time there will be increased certainty and convergence into technology trends, communication standards, customer responses, and government priorities/regulations. This certainty and understanding of the state and direction of smart grid will enable Toronto Hydro to embark on further demonstrations and larger scale deployments following the 3 years.
The following tables describe the services, technologies, and research and development efforts that encompass the 3 year plan. R&D efforts are used to support the services and technologies in this time frame, or to prepare for the 3-10 year plan.

TABLE 6: 3 YEAR PLAN – SMART GRID SERVICES

Smart Grid Service	Service Description
Bidirectional Power Flow Support	Infrastructure will support the two-way flow of power, such as in terms of generation, load and short circuit capacity, protection and control, stability, and supply/demand balance.
Distributed Energy Interface Support	Support any interface between distributed energy sources and the grid, such as inverter-based, synchronous, or induction, along with communications and controls.
Distributed Energy Connection Process	Streamline the connection process of distributed energy, including generation and storage, enabling customers to install clean and green energy sources with minimal hassle and in short timing.
System Loss Detection	Sensors, communications, and processing to calculate location of system losses (primarily focused on non-theft losses).
Grid-Wide Communications	Secure, high bandwidth, low latency, robust, two-way communications network that can enable all smart grid devices to speak to each other and to back office systems.
Self-Healing Grid	Automatic fault detection, location, sectionalisation, isolation, and restoration to restore as many customers as soon as possible in the event of an outage.
Vault Monitoring	Communicating grid sensors that can monitor the condition inside vaults and report back alarms and statuses to the utility.
Theft of Power Detection	Devices or programs which can identify locations of power theft. Examples include transformer and customer smart metering, and usage pattern recognition.
Advanced Asset Management	Advanced asset management models to optimize and mitigate risks in an aging yet evolving infrastructure.
Mobile Workforce Support	Supply workforce with mobile computing and information capabilities for effective and efficient work execution.

Integrated Outage Management	Mitigating outage occurrences via a network of information and automation. Examples include integrating the outage management system (OMS) with outage reporting smart meters, a self-healing grid, real time field information, restoration time estimates, and outage reporting in-home displays or customer mobile phones.
Identity and Access Management	Ensure security on worksites, the office, or company applications through identifying the user and granting appropriate access.
Cyber Security	Ensure cyber security throughout the grid, including communicating grid, metering, and in-home devices.
Billing, Energy, Outage, Carbon Information	Supply customers with information regarding their billing, energy usage, outage status, and carbon footprint information, such as through a web portal, in-home display, or mobile devices.
Web Services	Offering customers with self service via online web portal, such as billing and payment, monitoring electricity usage, checking outage information, changing personal information, and moving services.
Home Energy and Carbon Management	Program to help customers manage their energy consumption/production and carbon footprint, such as tracking, goal setting, projections, and recommended actions.
Conservation and Demand Management	Programs on conserving energy and managing customer demand, with a focus on peak demand reduction in the summer months.

TABLE 7: 3 YEAR PLAN – SMART GRID TECHNOLOGIES

Smart Grid Technology	Technology Description
System Loss Detection	Utilizing customer, transformer, feeder, and station smart meters, medium voltage measurement devices, communication networks, and processing applications to calculate the location of system losses.
Smart Meters	Meters with embedded intelligence and communication capabilities.
Advanced Metering Infrastructure	A network of smart meters, enabling services such as automatic meter reads, outage detection, and power quality monitoring.
Transformer Smart Metering	A smart meter installed at a transformer, enabling services such as load monitoring, outage detection, and theft of power detection.
Wide Area Network	A two-way communications network that spans a large geographical area, for grid-wide communications. Example usage will be for smart meter backhaul, smart grid communications, and once sufficiently proven, for grid operations and control.
Smart Sensors	Sensors with embedded intelligence and communications capabilities. Also

	known as intelligent electronic devices (IEDs).
Vault Monitoring	A system of smart sensors that monitors the conditions inside vaults and cable chambers, such as temperature, flood, and gas sensors.
Feeder Automation	Automatic feeder switching to enable a self-healing network.
Station Automation	Advanced sensing, relaying, and computing for distributed intelligence and processing of grid conditions, as well as to coordinate with feeder automation devices.
Network Automation	Applying further intelligence into the downtown underground secondary network system, with smart sensors, relays, meters, and autonomous controls.
Asset Management Decision Support	Advanced models, information, and decision support applications to optimize and mitigate risks in an aging yet evolving infrastructure.
Mobile Computing	Mobile computers and handheld devices with communication capabilities that connects to enterprise applications, to support effective and efficient work execution and documentation.
Service Oriented Architecture	IT enterprise architecture that enables interoperability between enterprise applications and databases to provide for integrated services. This allows for data exchange between different applications as defined by business processes.
Communicating Fault Sensors	Smart, communicating sensors that detect the presence of a fault on the system, to assist in identifying the fault location during outage restoration. Measurement of the actual fault current is highly desired.
Home Energy Management System	An application, such as online or installed in a computer, to help customers manage their energy consumption/production and carbon footprint, such as tracking, goal setting, projections, and recommended solutions for meeting goals.
In-Home Displays	Displays inside the customer’s property, such as a mobile device or built into a thermostat, which provides customers with information and control on their energy usage and carbon footprint.
Home Communication Gateway	A communication gateway that ties the utility’s local or wide area network with the customer’s home area network. This may be in the form of a smart meter or an in-home display.
Customer Web Portal	Online customer portal enabling customer self services, such as billing and payment, monitoring electricity usage, checking outage information, changing personal information, and moving services.

TABLE 8: 3 YEAR PLAN – SMART GRID RESEARCH AND DEVELOPMENT

Smart Grid R&D	Research and Development Description
Self-Healing Networks	Innovative means of realizing a self-healing grid, in regards to both power and communications. Examples include network topologies, adaptive protection, intelligent switches, and the use of graph theory to identify the optimal restoration path.
Distributed Energy Integration	Understand and identify solutions to accommodate a high penetration of distributed energy. Include load flow control, adaptive protection, power quality management, and islanding control.
Energy Storage	The exploration of energy storage to buffer intermittent and varying levels of generation and demand. Examples include grid-scale batteries, capacitors, pumped water, flywheels, compressed air, thermal, hydrogen, superconducting magnetic energy storage (SMES), and batteries in electric/plug-in hybrid electric vehicles.
Power Electronic Interfaces	Optimize the operation and mitigate the risks of power electronic interfaces between the grid and distributed generation/storage units. Examples include mitigation of resonance and stability issues, controlling distributed energy units for custom power (perfect power quality through controlled injection of active/reactive power), and intentional islanding/microgrid operation.
EV/PHEV Integration	Understand and identify solutions to accommodate a high penetration of plug in electric/hybrid electric vehicles to the grid. This includes a standardized charging plug, analysis of system capacity, managing intermittent demand (and potentially supply from vehicles), and metering, billing, and rate structures.
Metering Data Analytics	Data mining of metering information collected from customer and transformer smart meters. This can offer ancillary services such as transformer load monitoring, power quality monitoring, theft of power detection, and identifying custom solutions to customers to conserve energy.
Advanced Asset Management Models	Advanced models and algorithms to optimize and mitigate risks in an aging yet evolving infrastructure. Examples include the use of risk, economic, and probabilistic/stochastic models to determine maintenance requirements, loading of assets, asset life, etc.
Interoperability, Open Standards	Participate and keep abreast of developments of open standards between smart grid devices.
Consumer Research	Understanding and meeting the needs of the customer, offering information, options, and control of their energy usage and carbon footprint.

5.4 3 TO 10 YEAR PLAN

The 3-10 year plan involves the expansion of demonstrated initiatives from the smart grid community. Information, results, and lessons learned from the initial 3 year demonstration will contribute towards the scope and timeline of larger scale deployments.

Simultaneously, additional initiatives will be demonstrated, as characterised by:

- Requiring technological advances through research and development
- Requiring new or convergence of communications or connection standards
- Requiring products and solutions provided by vendors
- Building on the foundations of the 3 year plan

Research and development requirements of this plan are then used to support the services and technologies in this time frame, or to prepare for the 10-25 year plan.

The following tables describe the services, technologies, and research and development efforts that encompass the 3-10 year plan.

TABLE 9: 3 TO 10 YEAR PLAN – SMART GRID SERVICES

Smart Grid Service	Service Description
Energy Storage Integration	The integration of energy storage to buffer intermittent and varying levels of generation and demand. Storage can be grid-scale or distributed in customer's premise or vehicles.
High Penetration of Distributed Energy	Network with a high penetration of distributed energy to connect to the system, exchange bidirectional energy throughout the grid in real time.
PHEV-to-Grid Integration	Network that accommodates the charging of a large number of plug-in electric/hybrid electric vehicles. This requires a standardized charging plug, analysis of system capacity, managing intermittent demand (and potentially supply from vehicles), and metering, billing, and rate structures.
Line Loss Minimization	Measures to mitigate line loss for network efficiency and reducing environmental footprint. Examples include voltage conversion, peak demand reduction, power quality mitigation (including power factor correction), theft of power detection, and load re-routing.
Network Optimization	Optimize the day-to-day operation of the network, such as increasing network flexibility, visibility, and operability, phase balancing, peak demand reduction, and Volt/VAR control.
Power Quality Management	Monitor and mitigate power quality problems in the system, such as sags, swells, power factor, harmonics, and transients.

Online Call Centre	Enabling customers to make inquires online, such as through instant messaging applications and blogs.
Home Automation	Configuration and autonomous operation of home appliances, such as dishwashers and dryers, to reduce costs and carbon footprint.
Integrated Demand Offers	"Bundled" services that help customers manage and reduce demand, such as energy efficiency, demand response, and green energy.

TABLE 10: 3 TO 10 YEAR PLAN – SMART GRID TECHNOLOGIES

Smart Grid Technology	Technology Description
Real-Time Conditions Based Maintenance	Utilizing smart sensors to provide real time information to make maintenance and repair decisions.
Integrated Volt/VAR Control	A system that automatically optimizes the voltage and reactive power balance in the system, through monitoring and control of reactive power injection devices, such as capacitor banks and distributed energy units.
Phase Balancing	Monitoring, configuration, and switching of loads on system phases to balance and reduce system losses.
Power Line Metering	Smart metering and sensors on medium voltage lines to monitor system voltages, currents, and potentially power quality.
Adaptive Protection	Protection devices, such as circuit breakers and switches, with coordination characteristics that adapt to system conditions. This enables a network to accommodate varying distributed energy online as well as supporting dynamically reconfiguring systems, such as self-healing grids and microgrids.
Power Quality Monitors	Smart sensors that monitor power quality characteristics (voltage and frequency) in the system, such as sags, swells, power factor, harmonics, and transients.
Power Quality Conditioners	Power quality mitigation devices, including passive and active filters, as well as utilizing distributed energy sources for custom power (perfect power quality through controlled injection of active/reactive power).
Anti-islanding Control	Control algorithms, devices, and standards that prevent the formation of an "island" (isolated, self-powered, self-sustaining subset of the utility grid), even in the case of a high depth of penetration of distributed generation.
Distribution Energy Management System	Utility application that manages the stability and supply/demand balance of the distribution system. Traditionally used in large transmission networks, the Distribution EMS will become increasing critical as distributed generation connect to the medium voltage distribution systems.

Real Time Network Simulators	Network simulation application that, given real time conditions of the grid, computes the real time state of the network, including load flow, energy balance, stability, and power quality.
Energy Pattern Recognition	Pattern recognition applied to energy information collected from customer, transformer, feeder, and station smart meters to enable a variety of services such as demand reduction, loss identification, and theft of power detection.
EV/PHEV Charging Stations	Charging stations for plug in electric/hybrid electric vehicles with metering capabilities, as well as capacity for accommodating the vehicle charging load.
Home Area Network	Communications network in customer's premises to support smart appliances and energy management.
Smart Appliances	Home appliances, such as dishwashers and dryers, with built-in intelligence and communications functionalities to accept utility signals to reduce costs and carbon footprint.
Smart Homes	Customer residences with built-in home area network and smart appliances for management of energy and carbon footprint.

TABLE 11: 3 TO 10 YEAR PLAN – SMART GRID RESEARCH AND DEVELOPMENT

Smart Grid R&D	Research and Development Description
Fault Anticipation	Detection and recognition of fault signatures to anticipate a fault, and perform predictive maintenance or isolation activities to prevent its occurrence.
Adaptive Protection	Protection devices, such as circuit breakers and switches, with coordination characteristics that adapt to system conditions. This enables a network to accommodate varying distributed energy online as well as supporting dynamically reconfiguring systems, such as self-healing grids and microgrids.
Real Time Network Simulations	Network simulation application that, given real time conditions of the grid, computes the real time state of the network, including load flow, energy balance, stability, and power quality.
Islanding Control	Control algorithms, devices, and standards that intentionally creates, or avoids the formation of, an "island" (isolated, self-powered, self-sustaining subset of the utility grid), even in the case of a high depth of penetration of distributed generation.
Microgrid Control	Control algorithms, devices, and standards that control the creation and

	operation of a microgrid 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.
Data Mining	Mining of a utility's information rich enterprise databases to identify new potentials for improving the system or assisting the customer in energy/carbon management. Possible sources include metering, asset conditions, and operational information.
Weather, Supply, Demand Forecasts	Perform weather, supply, and demand forecasts to predict system behaviour and manage the varying levels of generation and load.

5.5 10 TO 25 YEAR PLAN

The 10-25 year plan is characterised by complete integration of technologies and services, maturing of technologies and services that were deployed in the first 10 years, collaboration between the utility and customers, and energy sourced primarily from renewable and clean generation. Proven smart grid technologies will span across the entire territory of Toronto Hydro. There will be further focus on providing services rather than resolving technology barriers.

New initiatives in this plan require the most significant amount of research and development, and have a comparable degree of uncertainty as seen in this stage of deployment. However the services that they enable represent the end state of the smart grid as defined by present drivers.

The following tables describe the services, technologies, and research and development efforts that encompass the 10-25 year plan.

TABLE 12: 10 TO 25 YEAR PLAN – SMART GRID SERVICES

Smart Grid Service	Service Description
Fully Distributed Energy and Intelligence	A network in which energy and intelligence are completely distributed amongst the network and coordinated with centralized sources and controls. A network where energy is generated and consumed locally, while centralized sources are only used as reserve. Network data and decision making are also localized for optimal timing and performance, while centralized processing are only used for high level monitoring and controls.
Fully Electrified Transportation	A network where all modes of transportation, personal vehicles and public transit (including subway and trains), are electrified and "plugged in" to the

	smart grid.
Microgrid Control	Control algorithms, devices, and standards that control the creation and operation of a microgrid 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.
Participatory Network	A system where customers and the utility work collaboratively, with shared responsibility, to achieve common set of objectives. Opportunities for new markets, demands, and mutual benefits.

TABLE 13: 10 TO 25 YEAR PLAN – SMART GRID TECHNOLOGIES

Smart Grid Technology	Technology Description
Fault Anticipation	Detection and recognition of fault signatures to anticipate a fault, and perform predictive maintenance or isolation activities to prevent its occurrence.
Microgrid Controllers	Control algorithms, devices, and standards that control the creation and operation of a microgrid 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.

TABLE 14: 10 TO 25 YEAR PLAN – SMART GRID RESEARCH AND DEVELOPMENT

Smart Grid R&D	Research and Development Description
Advanced Materials	Nanotechnology and self-healing materials, enabling better reliability, higher capacity, smaller dimensions, embedded intelligence, and lower environmental footprint.
HVDC	High voltage, direct current circuits that carry bulk currents with minimal losses and isolate electrical disturbances in the network.
Superconductors	Ultra low to zero resistance (near perfect to perfect conductivity) conductors that enable significant amounts of currents to be carried in a small footprint.

5.6 SYNERGISTIC VIGNETTES

At the core of the smart grid strategy is valuing true innovation through exploring synergies among initiatives. Following the identified services, technologies and research and development efforts above, four "synergistic vignettes" are described in Table 15 to illustrate the value of cross-functional services, and to realize new services. Each vignette is a potential narrative of how various components of the smart grid may look like once fully integrated. This approach at innovation opens up opportunities for new business models and customer service.

A mapping of the four vignettes to the list of enabling services, technologies, and R&D efforts in the roadmap are provided in Appendix B. It becomes evident the importance of integration to realize such vignettes.

TABLE 15: SYNERGISTIC VIGNETTES FOR INTEGRATED SMART GRID OPERATION

Participatory Network	Customers logs onto the utility's online instant messaging service to inquire about how they can save on their electricity bill. The utility's customer service representative loads up the customers' profile, understands their historical usage and projects to the end of the month, and lets the customers know if they are going to exceed their monthly plan. The representative then takes to customers to a list of customized plans on how they can save energy, money, and help the environment at the same time. The plan consists of a package of services that the customer can opt in or out, providing them information, options, and control over their energy use. Services include trading in energy efficient appliances, home energy and carbon management programs, home automation units, email alerts when the customer exceeds their budget, text message notifications before every peak pricing periods, and any financial assistance programs in which they quality for. The utility also offers two special programs – "GreenHome" and "GridAssist". GreenHome is a program to assists the customer to go green. Programs include a streamlined process to sign up for purchasing their own renewable energy generation, such as solar panels, with zero or low interest financing. Alternatively they can allow the utility to "rent their roofs" and install utility-owned solar panels, sharing the benefits with the utility. They can also donate a portion of their outputted green energy to a nearby community centre, sign up for free energy audits for their home, or have an "EV-Plug" installed in their home to charge their plug-in electric cars. GridAssist involves incenting the customer to help the utility's grid. Programs include allowing the utility to control their home appliances, such as air conditioners, hot water heaters, and dishwashers, whenever the demand of the

	power grid reach too high, or when the level of green energy in the system is too low and more polluting sources of generation will have to come online. Intelligence within the appliances ensures that the level of comfort in the home will not be compromised, and the customers will be given the ability to override the pre-programmed settings. Throughout the time the utility's representative stays online and responds to any questions that the customer might have. The customer simply adds any programs they want by "add to cart" and do a "checkout". They can then print a summary of all the services they signed up for and will be contacted by the utility shortly on what to do next.
Green Society	A decentralize generation network powered entirely from renewable and clean energy sources. Each building has become a "positive power plant" by generating both negawatts (conservation) and watts. Through an extensive carbon cap and trade system, society as a whole also becomes carbon neutral, even when considering the full life cycle, including manufacturing and transportation, of its generation sources. The smart grid infrastructure also has the capacity and intelligence to accommodate a wide array of generation options, including various interfaces. Distributed generation, distributed storage facilities, demand response, and intelligent applications ensure that supply and demand are balanced at all times despite the intermittent nature of renewable sources. Smart sensors, adaptive protection devices, sophisticated controls, and an extensive communications network ensure that power quality and system stability are well managed. Community power corporations, microgrids, and virtual power plants are also enabled to better manage the production and use of green energy. Potential, municipalities can become a positive energy source, and optimize their electricity with other districts. Centralized generation continues to exist but as reserves, while transmission systems tie both net positive and negative distribution networks together for energy trading. Mechanisms to promote green energy include zero or low interest financing for renewable generation, carbon cap and trade systems, and streamlined processes. To reduce the risks of financing green energies for customers, utilities and other third parities can enter contractual agreements with the customer to install their own generation while sharing benefits with the customer. Meanwhile, this dynamic, decentralized generation network also supports a fully electrified transportation infrastructure. Electrified vehicles, subway and train systems all plug in into the smart grid both as mobile loads and energy storage units.

Infrastructure Optimization	Day to day operation of the electric system is optimized with a dynamic, robust, and efficient grid. Safety, reliability, and supply security is ensured at all times. Distributed generation and storage facilities, as well as demand response and plug-in electric vehicles all work together to ensure supply demand balance. A network of intelligent sensors gives valuable information into the real time condition of the grid and warns of immediate work required. Automated controls perfects grid power quality and minimize the amount of losses, knowing exactly where they are. Valuable asset and grid operating information also flows back to back end intelligent systems to optimize the economic life and performance of assets. Workers are empowered with access to back end enterprise systems, such as maps and asset data, and work paperless to reduce impact on the environment.
Integrated Outage Restoration	A power outage occurs. Smart meters and communications immediately inform the utility that the customers' power is out. A self-healing grid automatically isolates the fault and restores power to as many customers as soon as possible. Distributed generation devices such as customer's solar panels and electric cars start feeding power to the customers as backup. The utility sends a text message to mobile and in-home devices acknowledging that the power is out and the utility is doing its best to restore power as quickly as possible. It also provides a best estimate given information captured from the grid and the circuit that was out of how long it will take to restore power. It further offers tips of what to do in the event of an outage. A crew is dispatched from the nearest location to confirm the location and reason for the outage, and provides a further update to the time till restoration. Using advanced tools and equipments, they proceed to remedy the cause of the outage and bring power back as soon as possible. Once power is restored, the utility confirms the restoration to all customers who were out, and sends a text message to their devices informing them of the restoration.

5.7 INNOVATION SUPPORT STRUCTURE

Smart grid is described as a "whitespace" in the organization – an amorphous territory where structured, well established, and formal strategies, processes, and history are absent, but where speed and flexibility reigns.[10] In the initial phases of deployment, the smart grid must be supported by a system that initiates, realizes, and sustains constructive innovation. Systems, processes, and people must be coordinated, aligned, and paced to bring true value with innovation. Table 16 identifies the key items to initiate and sustain innovation for the smart grid.

TABLE 16: ELEMENTS OF THE INNOVATION SUPPORT STRUCTURE

Strategic Planning	• Clear objectives and vision, focused strategies, and realistic roadmap to turn innovation into true value • Keep abreast of market trends, customer needs, government priorities, and regulatory support • Innovation efforts must support vision, disruptive innovation and technologies removed, feasibility assessed, risks managed, timelines aligned, and will contribute towards the overall well-being of society, the environment, and the organization • Balance of priorities with core business functions such as infrastructure renewal • Continual Stakeholders involvement
Business Process Management	• Portfolio, program, and project management • Direct progression from an open, unstructured concept to a controlled yet dynamic and flexible implementation • Coordinate cross-divisional efforts • Ensure benefits attainment
Organizational Support	• Centralized coordination and planning, with decentralized innovation and action • Steering Committee for executive monitoring and key decision making • Set up Innovation and Sustainability Office to initiate, manage, and sustain constructive innovation efforts • Cross-functional working group for program execution
Energy Delivery Infrastructure	• Renew aging infrastructure to sustain power delivery (i.e. Project Rebuild) • Bidirectional power flow support, including advanced sensing, control, and protection • Work procedures and protection for safe operations

[10] N. Nohria, M.C. Maletz, "Managing in the Whitespace," Harvard Business Review, Feb 2001, http://hbswk.hbs.edu/archive/2064.html

Strategic Alliance and Equipment Standards	• Strategic alliance with vendors and manufacturers to co-develop products to meet the needs of the smart grid • Collaboration between engineering and procurement to select the most suitable products • Standards to support smart grid, especially in the areas of integrating equipments with communications and for bidirectional power flow
Grid-Wide Communications	• A superhighway of bidirectional communications network for exchange of information and intelligence • Security measures • Communication standards for interoperability • Forecast communications requirements and convergence of protocols
Enterprise Applications and Integration	• Service enabling applications for customers and utility personnel • Integration between enterprise systems through a service oriented architecture and enterprise service bus (ESB)
Customer Relations	• Ensure that customers' needs are satisfied • Anticipate customer needs • Guide progression into a participatory network
Marketing and Communications	• Internal communications enables workers to understand and embody smart grid, empowering actions and further visions • Well thought out plan to communicate with customers • Open forums and marketing campaigns to engage the customer and encourage participation • Technical publications to work together with the research community
Resources and Training	• Need for both specialists and generalists • New skill sets required, especially in the areas of engineering, trades, and customer research • Knowledge capture and retention

6 KEY RECOMMENDATIONS

The key recommendations resulting from the research and analysis in this report are presented below in Table 17. They represent necessary and fundamental steps for the successful launch of smart grid at Toronto Hydro. Implementation of these recommendations is not consecutive, but overlap in a number of instances.

TABLE 17: KEY RECOMMENDATIONS FOR LAUNCHING SMART GRID

1 Engage and align with external stakeholders for Toronto's Smart Grid Plan	• Align with the Government of Ontario's Green Energy and Economy Act (Bill 150) upon legislation and regulation • Collaborate with the City of Toronto for the application of smart grid to address the City's Climate Change Plan • Coordinate with the Ontario Energy Board to expedite effective smart grid regulation • Educate Customers
2 Launch campaign on Toronto's smart grid	• Develop communications strategy and plan • Launch internal campaign to educate and engage internal staff on smart grid • Launch external campaign for customers and the industry • Attract new workforces and form strategic partnerships
3 Convene steering committee, innovation and sustainability office, and working group	• Steering Committee for executive monitoring and key decision making • Innovation and Sustainability Office to centralize strategic planning and management of overall smart grid portfolio. Align with external industry and government priorities • Cross-functional working Group with representation of key stakeholders in the organization for program execution
4 Training and education	• Develop and strengthen key competencies required for smart grid • Allocate sufficient resources to build momentum and reach tipping point • Capable of designing, developing, and operating the smart grid • Extend training and education to customers
5 Launch Smart Community demonstration	• Launch sizable demonstration project to create a "Smart Grid Community", as indicated in the 3 year plan of the Smart Grid Roadmap (Figure 4) • Develop detailed implementation plan with program scope, technology selection, costs and options, and business case • Integrate plan with 10 year capital plan and Electricity Distribution Rates filing process

Ontario Smart Grid Forum

In 2008, the Ontario Smart Grid Forum was convened to establish a common vision of Ontario's smart grid and its benefits, as well as develop recommendations for advancing it in Ontario. The forum consists of executives from industry leaders, including: BOMA, Burlington Hydro, Hydro Ottawa, Hydro One, Independent Electricity System Operator, Ministry of Energy and Infrastructure, Ontario Centres of Excellence, Ontario Energy Board, Ontario Power Authority, Toronto Hydro, University of Waterloo, and Veridian. Key recommendations from the Forum's report are referenced as below.

Key Recommendations from the Ontario Smart Grid Forum Report

Presented below are some of the key recommendations that follow in the Forum's Report. They reflect the central belief that Ontario should develop a smart grid to improve the prosperity of its citizens, the performance of its electricity system and the environment. The rapid development of a smart grid to benefit electricity consumers and advance environmental initiatives should be the policy of the Province of Ontario.

- The Ministry of Energy and Infrastructure should facilitate the development of Ontario's smart grid through legislation, regulation or other available means that clarify authorities, establish requirements or create incentives for those entities investing in Ontario's electricity system to accelerate the deployment or enhance the functioning of smart grid technologies.
- Consumers should pay prices that reflect the cost of energy at different times.
- In order to plan and operate the grid reliably and efficiently, distributors, transmitters, the OEB, OPA and the IESO should work together to:
  - develop requirements for and propose sufficient monitoring of distribution connected generation, energy storage, and responsive load;
  - determine the authority necessary to direct the operation of these facilities, the conditions under which their operation could be directed and any compensation that would be provided to the facility;
  - propose contractual and pricing arrangements with distribution connected generation, energy storage, and responsive load that support efficient grid operations and are consistent with the operation of the wholesale electricity market;
  - coordinate the development and implementation of grid control and information systems to facilitate the actions listed above.
- A Task Force led by the Ministry of Economic Development and involving other relevant Ministries should be created consisting of representatives from the auto sector (vehicle manufacturers and suppliers) electricity sector (OEB, IESO, OPA, distributors and generators) and universities to develop a comprehensive plan for enabling plug-in electric vehicles in Ontario. The plan would address policy, financial, and electricity system impacts of substantial electric vehicle penetration and identify what is required to ensure that vehicles can be charged as they develop. The Task Force should link to the ongoing collaborative work by the Electric Power Research Institute (EPRI), the Society of Automotive Engineers (SAE) and standards development organizations to develop electric vehicles standards.
- Utilities, the IESO, the OPA, universities and OCE should conduct research and development related to smart grids to advance Ontario's leadership position in this area, promote innovation and develop green jobs in the province. The OCE should facilitate the development of a task force to produce a framework for smart grid research in Ontario that would include targeted amounts of funding and proposed funding mechanisms.

7 A CALL TO ACTION

The City of Toronto has been known as the hub of Canada – the financial hub, the cultural hub, and the entertainment hub. With firm dedication and collaboration from the Ontario government, Toronto government, Toronto Hydro, and other key stakeholders, Toronto can also become the intelligent and sustainable energy hub of Canada. The smart grid is the avenue to make this happen.

Through innovation and the strategic application of information, communication, and electronic/electrical technologies, the smart grid can optimize the electric infrastructure in a time of a convergence of risks, enhance customer experience in a digital era, and meet the province and city's agenda for environmental sustainability and a green economy. It is a phenomenal task, but it is necessary. And we're prepared to lead this effort.

It is thus a time for change, for turning vision into action. Guided by our vision, objectives, strategy, and roadmap, we can realize a path through the challenges of deployment into a future of innovation and sustainability. The recommendations in this report envision actions taken by stakeholders throughout the organization to work collaboratively towards a smart grid. This involves initiating the transformation and innovation effort, engaging key stakeholders and customers, convening core groups in commencing smart grid activities, preparing workforce for modernization, and launching Toronto's Smart Grid Community.

The smart grid represents the greatest effort the industry has seen to "plug in" – plug in our customers, plug in the environment, plug in new technologies, and plug in our grid. The time is right, and the time is now.

APPENDIX A:

MAPPING SMART GRID INITIATIVES WITH STRATEGIC OBJECTIVES

			Smart Grid Objectives: Climate Protection					Energy Security					Customer Satisfaction					
Timeline	Smart Grid Initiatives	Total Count	1.1 Zero Footprint	1.2 Distributed Energy	1.3 Streamlined Processes	1.4 Microgrid/Community Energy/VPP	1.5 Electrified Transportation	2.1 Modernize Aging Infrastructure	2.2 Manage Power Quality	2.3 Visibility and Control Throughout	2.4 Improve Utility Operations	2.5 Physical and Cyber Security	3.1 Timely Information	3.2 New Forms of Communication	3.3 Energy Controls	3.4 New Customer Service Models	3.5 Advices from the Utility	3.6 Incentives and Financial Support
Now-3 years																		
Services	Bidirectional Power Flow Support	11	✓	✓	✓	✓	✓	✓	✓	✓	✓				✓		✓	
	Distributed Energy Interface Support	11	✓	✓	✓	✓	✓	✓	✓	✓	✓				✓		✓	
	Distributed Energy Connection Process	7	✓	✓	✓	✓	✓									✓	✓	
	System Loss Detection	3	✓					✓		✓								
	Grid-Wide Communications	11		✓		✓	✓	✓	✓	✓	✓	✓	✓	✓	✓			
	Self-Healing Grid	5				✓		✓	✓	✓	✓							
	Vault Monitoring	4	✓					✓		✓	✓							
	Theft of Power Detection	6	✓					✓		✓	✓	✓					✓	
	Advanced Asset Management	11	✓	✓	✓	✓	✓	✓	✓	✓	✓		✓				✓	
	Mobile Workforce Support	5	✓		✓						✓					✓	✓	
	Integrated Outage Management	9		✓		✓	✓	✓	✓	✓	✓		✓				✓	
	Identity and Access Management	1										✓						
	Cyber Security	2										✓					✓	
	Billing, Energy, Outage, Carbon Information	11	✓	✓		✓	✓			✓			✓	✓	✓	✓	✓	✓
	Web Services	8	✓		✓	✓							✓	✓		✓	✓	✓
	Home Energy and Carbon Management	10	✓	✓		✓	✓	✓					✓		✓	✓	✓	✓
	Conservation and Demand Management	9	✓	✓		✓		✓					✓		✓	✓	✓	✓
Technologies	Smart Meters	14	✓	✓		✓	✓	✓	✓	✓	✓		✓	✓	✓	✓	✓	✓
	Advanced Metering Infrastructure	14	✓	✓		✓	✓	✓	✓	✓	✓		✓	✓	✓	✓	✓	✓
	Transformer Smart Metering	5	✓					✓	✓	✓	✓							
	System Loss Detection	3	✓					✓		✓								
	Wide Area Network	11		✓		✓	✓	✓	✓	✓	✓	✓	✓	✓	✓			
	Smart Sensors	8	✓	✓		✓	✓	✓	✓	✓	✓							
	Vault Monitors	4	✓					✓		✓	✓							
	Feeder Automation	5				✓		✓	✓	✓	✓							
	Station Automation	5				✓		✓	✓	✓	✓							
	Network Automation	5				✓		✓	✓	✓	✓							
	Asset Management Decision Support	9	✓	✓	✓	✓	✓	✓	✓	✓	✓							
	Mobile Computing	3	✓		✓						✓							
	Service Oriented Architecture	4			✓						✓		✓				✓	
	Communicating Fault Sensors	6		✓		✓	✓	✓		✓	✓							
	Home Energy Management System	10	✓	✓		✓	✓	✓					✓		✓	✓	✓	✓
	In-Home Displays	9		✓		✓	✓						✓	✓	✓	✓	✓	✓
	Home Communication Gateway	6				✓							✓	✓	✓	✓	✓	
	Customer Web Portal	12	✓	✓	✓	✓	✓	✓					✓	✓	✓	✓	✓	✓
R&D	Self-Healing Networks	5				✓		✓	✓	✓	✓							
	Distributed Energy Integration	12	✓	✓	✓	✓	✓	✓	✓	✓	✓				✓	✓	✓	
	Energy Storage	11	✓	✓		✓	✓	✓	✓	✓	✓				✓	✓	✓	
	Power Electronic Interfaces	6	✓	✓		✓	✓	✓	✓									
	EV/PHEV Integration	9	✓			✓	✓	✓	✓	✓					✓	✓	✓	
	Metering Data Analytics	13	✓	✓		✓	✓	✓	✓	✓	✓		✓		✓	✓	✓	✓
	Advanced Asset Management Models	10	✓	✓	✓	✓	✓	✓	✓	✓	✓		✓					
	Interoperability, Open Standards	11	✓	✓	✓	✓	✓			✓	✓	✓	✓	✓	✓			
	Consumer Research	11	✓	✓	✓	✓	✓						✓	✓	✓	✓	✓	✓

			Smart Grid Objectives															
			Climate Protection					Energy Security					Customer Satisfaction					
		Total Count	Zero Footprint	Distributed Energy	Streamlined Processes	Microgrid/Community Energy/VPP	Electrified Transportation	Modernize Aging Infrastructure	Manage Power Quality	Visibility and Control Throughout	Improve Utility Operations	Physical and Cyber Security	Timely Information	New Forms of Communication	Energy Controls	New Customer Service Models	Advices from the Utility	Incentives and Financial Support
Timeline	**Smart Grid Initiatives**		**1.1**	**1.2**	**1.3**	**1.4**	**1.5**	**2.1**	**2.2**	**2.3**	**2.4**	**2.5**	**3.1**	**3.2**	**3.3**	**3.4**	**3.5**	**3.6**
3-10 years																		
Services	Energy Storage Integration	12	✓	✓	✓	✓	✓	✓	✓	✓	✓				✓	✓	✓	
	High Penetration of Distributed Energy	12	✓	✓	✓	✓	✓	✓	✓	✓	✓				✓	✓	✓	
	PHEV-to-Grid Integration	12	✓	✓	✓	✓	✓	✓	✓	✓	✓				✓	✓	✓	
	Line Loss Minimization	4	✓					✓		✓	✓							
	Network Optimization	6	✓			✓		✓	✓	✓	✓							
	Power Quality Management	11	✓	✓	✓	✓	✓	✓	✓	✓	✓				✓		✓	
	Integrated Demand Offers	10	✓			✓		✓		✓	✓		✓		✓	✓	✓	✓
	Online Call Centre	6			✓								✓	✓		✓	✓	✓
	Home Automation	11	✓	✓		✓	✓	✓					✓	✓	✓	✓	✓	✓
Technologies	Real-Time Conditions Based Maintenance	4	✓					✓		✓	✓							
	Integrated Volt/VAR Control	6	✓			✓		✓	✓	✓	✓							
	Phase Balancing	6	✓			✓		✓	✓	✓	✓							
	Power Line Metering	8	✓	✓		✓	✓	✓	✓	✓	✓							
	Adaptive Protection	8	✓	✓		✓	✓	✓	✓	✓	✓							
	Power Quality Monitors	8	✓	✓		✓	✓	✓	✓	✓	✓							
	Power Quality Conditioners	8	✓	✓		✓	✓	✓	✓	✓	✓							
	Anti-islanding Control	8	✓	✓		✓	✓	✓	✓	✓	✓							
	Distribution Energy Management System	12	✓	✓		✓	✓	✓	✓	✓	✓		✓		✓	✓	✓	
	Real Time Network Simulators	8	✓	✓		✓	✓	✓	✓	✓	✓							
	Energy Pattern Recognition	12	✓	✓		✓	✓	✓	✓				✓	✓	✓	✓	✓	✓
	EV/PHEV Charging Stations	10	✓			✓	✓	✓	✓	✓				✓	✓	✓	✓	
	Home Area Network	6				✓							✓	✓	✓	✓	✓	
	Smart Appliances	9	✓			✓		✓					✓	✓	✓	✓	✓	✓
	Web-Based Call Centre	5			✓									✓		✓	✓	✓
	Smart Homes	11	✓	✓		✓	✓	✓					✓	✓	✓	✓	✓	✓
R&D	Fault Anticipation	4						✓	✓	✓	✓							
	Adaptive Protection	8	✓	✓		✓	✓	✓	✓	✓	✓							
	Real Time Network Simulations	8	✓	✓		✓	✓	✓	✓	✓	✓							
	Islanding Control	9	✓	✓	✓	✓	✓	✓	✓	✓	✓							
	Microgrid Control	14	✓	✓	✓	✓	✓	✓	✓	✓	✓		✓	✓	✓	✓	✓	
	Data Mining	11	✓	✓		✓	✓	✓	✓	✓	✓		✓			✓	✓	
	Weather, Supply, Demand Forecasts	14	✓	✓		✓	✓	✓	✓	✓	✓		✓	✓	✓	✓	✓	✓
10-25 years																		
Services	Fully Distributed Energy and Intelligence	12	✓	✓	✓	✓	✓	✓	✓	✓	✓				✓	✓	✓	
	Fully Electrified Transportation	11	✓	✓	✓	✓	✓	✓	✓	✓					✓	✓	✓	
	Microgrid Control	13	✓	✓	✓	✓	✓	✓	✓	✓	✓			✓	✓	✓	✓	
	Participatory Network	16	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
Technologies	Fault Anticipation	4						✓	✓	✓	✓							
	Microgrid Controllers	14	✓	✓	✓	✓	✓	✓	✓	✓	✓		✓	✓	✓	✓	✓	
R&D	Advanced Materials	4	✓					✓	✓		✓							
	Superconductors	4	✓					✓	✓		✓							
	HVDC	4	✓					✓	✓		✓							

APPENDIX B:

SMART GRID INITIATIVES REQUIRED IN SYNERGISTIC VIGNETTES

Timeline	Smart Grid Initiatives	Vignette: Participatory Network	Vignette: Green Society	Vignette: Integrated Outage Restoration	Vignette: Optimized Infrastructure
Smart Grid Services					
Now-3 years	Bidirectional Power Flow Support		✓	✓	✓
	Distributed Energy Interface Support		✓	✓	✓
	Distributed Energy Connection Process	✓	✓		✓
	Grid-Wide Communications	✓	✓	✓	✓
	Self-Healing Grid			✓	✓
	Vault Monitoring				✓
	Theft of Power Detection				✓
	Advanced Asset Management	✓	✓	✓	✓
	Mobile Workforce Support			✓	✓
	Integrated Outage Management		✓	✓	
	Identity and Access Management				
	Cyber Security				
	Billing, Energy, Outage, Carbon Information	✓	✓		
	Web Services	✓	✓	✓	
	Home Energy and Carbon Management	✓	✓	✓	
	Conservation and Demand Management	✓	✓	✓	
3-10 years	Energy Storage Integration	✓	✓	✓	✓
	High Penetration of Distributed Energy	✓	✓	✓	✓
	PHEV-to-Grid Integration	✓	✓		✓
	Line Loss Minimization		✓		✓
	Network Optimization				✓
	Power Quality Management				✓
	Integrated Demand Response		✓	✓	✓
	Online Call Centre	✓		✓	
	Home Automation	✓	✓	✓	
10-25 years	Fully Distributed Energy and Intelligence		✓	✓	✓
	Fully Electrified Transportation		✓		✓
	Microgrid Control		✓	✓	✓
	Islanding Control		✓	✓	✓
	Participatory Network	✓	✓	✓	✓

Timeline	Smart Grid Initiatives	Vignette			
		Participatory Network	Green Society	Integrated Outage Restoration	Optimized Infrastructure
Smart Grid Technologies					
Now-3 years	Smart Meters	✓	✓	✓	✓
	Advanced Metering Infrastructure	✓		✓	✓
	Transformer Smart Metering	✓		✓	✓
	Wide Area Network	✓	✓	✓	✓
	Smart Sensors		✓	✓	✓
	Vault Monitors				✓
	Feeder Automation			✓	✓
	Station Automation			✓	✓
	Network Automation			✓	✓
	Asset Management Decision Support	✓	✓	✓	✓
	Mobile Computing			✓	✓
	Communicating Fault Sensors			✓	
	Home Energy Management System	✓	✓	✓	✓
	In-Home Displays	✓	✓	✓	
	Home Communication Gateway	✓		✓	
	Demand Reponse Dispatch	✓	✓	✓	
	Customer Web Portal	✓	✓	✓	
3-10 years	Real-Time Conditions Based Maintenance				✓
	Integrated Volt/VAR Control		✓		✓
	Phase Balancing		✓	✓	✓
	Power Line Metering		✓	✓	✓
	Adaptive Protection		✓	✓	✓
	Power Quality Monitors		✓	✓	✓
	Power Quality Conditioners		✓	✓	✓
	Anti-islanding Control		✓	✓	✓
	Distribution Energy Management System		✓	✓	✓
	Real Time Network Simulators		✓	✓	✓
	Energy Pattern Recognition	✓	✓		✓
	EV/PHEV Charging Stations	✓	✓		✓
	Home Area Network	✓		✓	
	Smart Appliances	✓	✓	✓	
	Web-Based Call Centre	✓		✓	
	Smart Homes	✓	✓	✓	
10-25 years	Fault Anticipation			✓	✓
	Microgrid Controllers		✓	✓	✓
Smart Grid Research and Development					
Now-3 years	Self-Healing Networks			✓	✓
	Distributed Energy Integration	✓	✓	✓	✓
	Energy Storage	✓	✓	✓	✓
	Power Electronic Interfaces	✓	✓	✓	✓
	EV/PHEV Integration	✓	✓		✓
	Metering Data Analytics	✓	✓		✓
	Advanced Asset Management Models	✓	✓	✓	✓
	Interoperability, Open Standards	✓	✓	✓	✓
	Consumer Research	✓	✓	✓	✓
3-10 years	Fault Anticipation			✓	✓
	Adaptive Protection		✓	✓	✓
	Real Time Network Simulations		✓	✓	✓
	Islanding Control		✓	✓	✓
	Microgrid Control		✓	✓	✓
	Data Mining	✓			✓
	Weather, Supply, Demand Forecasts	✓	✓	✓	✓
10-25 years	Advanced Materials				✓
	Superconductors				✓
	HVDC				✓

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INTERROGATORY 109:

Reference(s): G1/T1/S1/p5 L6-12

The referenced lines refer to distributed generation, the connection of renewable generation and the reliable connection of microgrids, community energy and virtual power plants.

a) Please explain THESL's concept of a "microgrid"?

b) Please explain THESL's concept of a "virtual power plant"?

c) Please identify all of the projects in the application which relate to the objectives identified in the reference.

d) Please describe how THESL will determine where on its system to prepare for connection of renewable generation, microgrids and virtual power plants.

RESPONSE:

a) THESL adopts the definition of a microgrid described in the Report of the Ontario Smart Grid Forum, *Enabling Tomorrow's Electricity System (February 2009)*: "A micro-grid is an integrated energy solution that serves a group of consumers, such as a neighbourhood or a town, or a single large consumer, such as a university. Micro-grids use a variety of energy, communications and computer technologies to allow the consumers served by them to meet all, or a large portion, of their total energy needs (electric and thermal) with devices that form part of the micro-grid. While a micro-grid can be designed to allow those it serves to achieve energy self-sufficiency, it is generally not independent of the larger electricity system. Instead, it buys and sells electricity from the grid to take advantage of price differentials and when necessary to address surpluses or deficits in micro-grid production. For

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participants, micro-grids can deliver local control of energy production, more efficient use of combined heat and power, greater reliability and improved power quality, and the ability to better tailor their energy supply to their energy needs and environmental values."

b) THESL describes the concept of a virtual power plant as a collection of distributed generators, renewable or non-renewable, which are coordinated through administration, regulatory, and finance levels, to aggregate their electrical output for the purposes of improving the economics, environmental performance, and grid operations of distributed generation. Along with distributed generators, this definition includes the aggregation of load control for demand response.

c) All projects in this Application related to the GEGEA are listed in Exhibit G1, Tab 1, Schedule 1, pages 11-12.

d) Renewable generation under the GEA FIT program is user driven and can theoretically appear anywhere on the system. With respect to photovoltaic generation, service territories with larger roof-top areas will likely be better candidates.

THESL has defined microgrid and virtual power plant initiatives as a part of the ten- to 25-year plan in the Smart Grid Roadmap. THESL will determine where on its system to prepare for microgrids and virtual power plants when enabling technologies and regulations are present, and when there is sufficient penetration of distributed generation in THESL's service territory.

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INTERROGATORY 110:

Reference(s): G1/T1/S1/p 7

In order to test various smart grid initiatives THESL selected a community in North York, consisting of 10 feeders and 2 substations.

Please explain how the lessons learned in North York will be useful in the remainder of the city given that lessons from this pilot may not be applicable elsewhere due to differing feeder and substation configurations throughout the city.

RESPONSE:

The feeder and substation configurations of the Smart Community in the North York area are largely representative of the majority of the city, including the former districts of Etobicoke, York, East York, and Scarborough, as well as portions of former Toronto. The lessons to be learned in the Smart Community will be very useful for these areas of the city because of this similarity in configuration. Moreover, sensor projects (e.g., transformer smart metering) and information technology projects are independent of feeder and substation configurations, and thus can be applied throughout THESL's service territory.

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INTERROGATORY 111:

Reference(s): [G]1/T1/S1

Please indicate if THESL has any plans for coordination amongst distributors and transmitters with regard to infrastructure to support renewable generation and with regard to Smart Grid initiatives.

RESPONSE:

THESL works closely with the Coalition of Large Distributors on points of mutual interest. THESL plans to work closely with the Coalition on infrastructure support issues for renewable generation.

In addition, THESL plans to coordinate with distributors and transmitters with regard to Smart Grid initiatives, through ongoing discussions and collaborations with the Ontario Smart Grid Forum, Electricity Distributors Association, Canadian Electricity Association, CEATI, Utilities Telecom Council, and Institute of Electrical and Electronics Engineers. THESL further plans to actively participate at various conferences and seminars to share results and lessons learned.

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INTERROGATORY 112:

Reference(s): **G1/T1/S1/p3/line21**

Please explain what THESL means by the term "nested" outages.

RESPONSE:

THESL describes a nested outage as an outage that is contained within a larger outage area. Upon resolution of the disturbance that caused the larger outage, the nested outage will remain.

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INTERROGATORY 113:

Reference(s): **G1/T1/S1/p7**

It is stated that: "The three-year plan of the smart grid roadmap is intended to establish Toronto's Smart Community, which is a demonstration area where prioritized initiatives can be tested, processes developed, customer acceptance understood, and operating procedures created."

a) Please state if this community is made up of a contiguous geographical area.
b) Please state if this community is made up of a contiguous electrical area.
c) Please state if the electrical configuration is representative of all areas of the distribution system.
d) Please state how many switches are encompassed by the 10 feeders in the community.

RESPONSE:

a) Yes, the community is made up of a contiguous geographical area.

b) Yes, the community is made up of a contiguous electrical area.

c) No, the electrical configuration is not representative of all areas of the distribution system.

d) There are a total of 107 overhead three-phase gang operated switches on the ten feeders, consisting of both SCADA-controlled and manually-operated switches.

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INTERROGATORY 114:

Reference(s): **G1/T1/S1/p11-13**

Tables 2 and 3 summarise the 2010 Smart Grid Programs. The tables indicate that an investment of $6.7million is required in information technology to support and implement $3 million of investment in smart grid operations projects.

a) Does THESL have information which would provide a benchmark for such expenditure ratios in other distribution companies or in the literature or in earlier projects?

b) How does this ratio of expenditure compare with implementation of the SCADA system itself?

c) For each of the capital and operations amounts in Table 3 for each project please provide a more detailed breakdown as to how the number was obtained, including labour (internal and external) and type of labour and materials and equipment.

RESPONSE:

a) The current embryonic state of Smart Grid technologies does not provide readily comparable benchmarks for assessment. Comparisons to other distribution companies' implementations are not available to THESL. THESL engaged a major consulting firm, with significant North American and global experience in the field, to help in creating a high level IT Smart Grid plan prefiled as Exhibit G1, Tab 1, Schedule 1 that aligns with the strategic direction.

The Smart Grid IT Strategy has established a Roadmap and established projects and estimates to support the business requirements using Smart Grid technology. These costs have been used as the THESL estimates for IT spending on Smart Grid

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beginning in 2010.

b) Prior to the amalgamation of the former utilities across Toronto, each utility had its own SCADA system. When the amalgamation took place, the SCADA systems were consolidated, and have since been enhanced and upgraded over the years. It is therefore impractical to provide conclusive numbers relating to the ratio of expenditures as they relate to the SCADA system itself.

As more SCADA devices begin to adopt TCP/IP as their common communication protocol, tighter integration with IT is required, and the security implications from smart grid are significant. End to end security is required to mitigate the risk of "computer hackers", organized crime or other unauthorized access to THESL's network to gain access and interfere with the SCADA system.

The end result is that IT expenditures relative to SCADA will substantially increase with the deployment of smart grid. IT and SCADA must now have end to end architectures, security and integrated operations. Therefore, historical comparisons of SCADA to IT are not accurate benchmarks for future expenditures.

c) The table below provides the detailed support to the $6.7M investment for information technology support to the Smart Grid Program.

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Table 1: 2010 Smart Grid program - Information Technology Cost Detail - $000s

Project	Internal Labour	Consulting Services	External	Hardware	Software	Other	Total
Customer Portals Pilot	125	250	260	80	190	43	**948**
Smart Grid Metering Pilot	60	140	0	70	120	30	**420**
Integration Architecture & Design	75	440	325	0	0	40	**880**
Access Network Pilot	80	330	318	250	210	60	**1,248**
Internal Network Readiness	180	0	360	870	0	70	**1,480**
Smart Grid Network Security	75	590	289	150	580	80	**1,764**
	595	**1,750**	**1,552**	**1,420**	**1,100**	**323**	**6,740**

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INTERROGATORY 115:

Reference(s): G1/ T1/ S2/p3 and pp.8-9

On page 3, THESL describes projects to allow automation of the secondary network. This is stated as the only project "not specifically piloted in the Smart Community area."

On pages 8-9, THESL states that it plans to install monitoring equipment on submersible transformer vaults.

a) By what criteria did THESL determine that automation of the secondary network and submersible vault monitoring are smart grid investments? How does this ratio of expenditure compare with implementation of the SCADA system itself?
b) Please identify separately, capital expenditures related to the GEA and that related to normal system expansion/reinforcement.
c) If this project were to proceed as described by THESL please state the anticipated benefits including quantification of them.

RESPONSE:

a) THESL adopts the definition of "smart grid" as identified in the GEGEA:

> *"Smart grid" means the advanced information exchange systems and equipment that when utilized together improve the flexibility, security, reliability, efficiency and safety of the integrated power system and distribution systems, particularly for the purposes of,*
>
> *a) Enabling the increased use of renewable energy sources and technology, including generation facilities connected to the distribution system;*

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> *b) Expanding opportunities to provide demand response, price information and load control to electricity customers;*
>
> *c) Accommodating the use of emerging, innovative and energy-saving technologies and system control applications; or*
>
> *d) Supporting other objectives that may be prescribed by regulation.*

Based on this definition, the following three criteria were used in determining the mentioned projects as smart grid investments:

1. Exhibit communication and information technology capabilities (*"advanced information exchange"*)
2. Integration between equipment and information exchange systems (*"when utilized together"*)
3. Directed at the objectives as defined in the GEGEA (*"improve the flexibility, security, reliability, efficiency and safety of the integrated power system and distribution systems, particularly for the purposes of, a) enabling the increased use of renewable energy sources and technology, including generation facilities connected to the distribution system; b) expanding opportunities to provide demand response, price information and load control to electricity customers; c) accommodating the use of emerging, innovative and energy-saving technologies and system control applications; or d) Supporting other objectives that may be prescribed by regulation.)*

Given the above criteria for determining Smart Grid investments, SCADA is a mechanism to enable certain components of selected Smart Grid applications, in

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particular it provides a channel for data communications. The secondary network automation initiative is planned to leverage on SCADA for communications. The submersible vault monitoring initiative utilizes a transformer smart meter for communications, and hence it leverages on the Advanced Metering Infrastructure (AMI) and the expenditure is expected to be less than 10% of an implementation through SCADA. The selection of communication channels is based on a number of criteria including geography, coverage, bandwidth, and existing installed equipments.

b) The capital expenditures related to the secondary network automation as identified in Table 2 of Exhibit G1, Tab 1, Schedule 2, and for submersible vault monitoring as identified in Table 5 of the same schedule, are related to the GEA alone and are not related to normal system expansion/reinforcement.

c) The anticipated benefits of secondary network automation initiative are described in Exhibit G1, Tab 1, Schedule 2 pages 3-4. This particular, this project entails one network vault for small scale demonstration only, and there are no significant and immediate costs or time savings are expected. The primarily purpose of the demonstration is to learn about the technology, its impact upon to THESL operations, and to collect valuable information which will enable THESL to properly evaluate the potential for wider scale deployment.

There is nevertheless significant value from the opportunity that exists should the project prove to be successful and the initiative deployed, with anticipated quantifiable benefits including:

- Provide increased visibility into the secondary network condition (up to 60% of condition criteria);

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- Proactive maintenance of all flood conditions in the vault; and
- Mitigate up to 100% of network overloading conditions from direct load measurements and transformer temperature monitoring;

Other potentially significant benefits of this pilot project include:

- Protection of worker and public safety;
- Prevention of environmental damage from transformer oil spills;
- Support for the integration of renewable generation into system, including the secondary network, as required by the GEGEA and deemed condition of THESL's distribution licence; and
- Preparation for increased adoption of plug-in electric or hybrid electric vehicles.

The anticipated benefits of submersible vault monitoring initiative are described in Exhibit G1, Tab 1, Schedule 2, page 9. Similar to the secondary network automation project, the primarily purpose of this project is for demonstration only, to learn about the technology, its impact to THESL operations, and to collect information which will enable THESL to further evaluate the potential for wider scale deployment.

Here too there is significant value from the opportunity that exists should the project prove to be successful and the initiative deployed, with anticipated quantifiable benefits including:

- Provide increased visibility into the submersible distribution transformer vault condition (up to 100% of condition criteria);
- Mitigate up to 100% of transformer overloading conditions by monitoring and load and transformer temperature;

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- Proactive maintenance of all flood conditions in the vault;
- Detection of up to 100% of technical and non-technical losses; and
- Improve outage response time.

Other benefits significantly impact the opportunity cost of this pilot project, including:

- Protection of worker and public safety;
- Prevention of environmental damage from transformer oil spills;
- Support for the integration of renewable generation into system, including the secondary network, as required by the GEGEA and deemed a condition of THESL's distribution licence;
- Preparation for increased adoption of plug-in electric or hybrid electric vehicles; and
- Improve transformer-to-customer connection relationships in information records.

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INTERROGATORY 116:

Reference(s): G1/T1/S2/p 1

As part of the Feeder Automation project THESL states that it plans to leverage previously installed SCADA controlled switches in order to perform 'self-healing' capabilities. Over 400 such switches are stated as having been installed.

Please describe in detail, for this leveraging of existing assets for smart grid capabilities:

a) The incremental changes that are to be made;
b) The incremental costs;
c) Confirm that these components were not part of any previous application and are not already in the rate base;
d) Please provide further detail on the software, control devices and any other ancillary devices that THESL is planning to utilize for this initiative;
e) Please quantify the payback or benefit anticipated from this initiative;
f) Please describe the anticipated lessons learned from this demonstration.

RESPONSE:

a) The existing SCADAMate switches need to be upgraded for automatic restoration. The incremental changes that need to be made include:
   - Replace previous version of switch controller to the 5801 model;
   - Replace existing communication radio with SpeedNet radio;
   - Install new repeater radios where needed to enable the establishment of a meshed communication network; and
   - Upload IntelliTEAM logic to new 5801 switch controller.

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There are also existing installed SCADA controlled switches not suitable to be upgraded. In these instances, the switch unit will need to be replaced with a new SCADAMate switch with the above mentioned components.

b) Depending on the vintage of existing installed equipment, the incremental material cost would be up to $20,000 per unit. Labour cost to upgrade the RTU and radio communication is $6,400 per unit.

c) THESL confirms that these components were not part of any previous application and are not already in the rate base.

d) The feeder automation project utilises SCADAMate switches with 5801 switch controllers, uploaded with the "IntelliTEAM II" software logic. Together they perform automatic fault detection, location, sectionalisation, isolation, and restoration function in the event of a power interruption.

The automation scheme functions on a peer-to-peer meshed communication network, and is formed by IP-based SpeedNet radios installed with each SCADAMate switch, enabling information exchange and distributed decision making amongst switches. Repeater radios will also be installed where needed to establish such a communication network.

In addition to the above, the Universal Interface Module (UIM) will be installed in substations to enable the protective relay or recloser control to function in the IntelliTEAM II logic to implement restoration decisions. When combined with

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SCADAMate switches installed on distribution feeders, it forms a fully automated self-healing network.

e) The anticipated benefits of feeder automation initiative are described in Exhibit G1, Tab 1, Schedule 2, page 2. This particular project entails the demonstration of the initiative with ten feeders, and the primarily purpose is to learn about the technology, its impact to THESL operations, and to collect information which will result in the evaluation to assess the merits of potential deployment.

There are direct quantifiable benefits from the ten feeder scheme alone, as well as the opportunity cost that exists should the project proves to be successful and the initiative deployed. These benefits include:

- Effectively identify segment of feeder that has experienced a fault, analyze loading conditions at the time of failure, determine available spare capacity on alternate supply points, and restore power to unaffected line segments in under 60 seconds, up to 100% of the time;
- 80% improvement in outage response time on average to the affected line segment due to a feeder trunk fault; and
- Increase monitoring points on each feeder by three times on average.

Other benefits that are not trivial to quantify include:

- Improve safety of workers through lessening the need to perform manual switching, especially under faulty conditions;
- Focus the efforts of system operators and field staff on more complex fault locating tasks, work dispatch, and corrective repair work;
- Better utilisation of feeder capacity and improve operational flexibility; and

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- Support the integration of renewable generation and plug-in electric or hybrid electric vehicles into system by real time monitoring of two way power flow and voltage profile.

f) The anticipated lessons learned from this demonstration include in-depth understanding of the available switch, controller, and communications technology, including functionality, security implications, installation, setup, testing, commissioning, and site verification. Moreover, there will be lessons learned in the process of applying new technology to the THESL operating context, in particular automation of outage restoration without human intervention.

Upon activation of the automation scheme, there will be insight regarding the strengths and limitations of the technology in its ability to perform automated power restoration, especially under complicated outage conditions (e.g., storm situation). Unforeseen benefits and challenges are also expected to be discovered. Control room and field experience will be captured. Information will also be collected which will result in the evaluation to assess the merits of potential deployment.

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INTERROGATORY 117:

Reference(s): G1/T1/S2/p 1

Feeder Automation is discussed on this page.

a) Please confirm that the Smart Community is made up of the ten worst performance feeders in the distribution network, and that there are no other feeders in the Smart Community. What are the current reliability statistics for the Smart Community?

b) Please provide current reliability statistics for the Smart Community.

c) Please state whether the current reliability statistics for the Smart Community are below the target reliability for feeders in the system.

d) Please state what actions were contemplated to improve the reliability of the Smart Community prior to passage of the Green Energy Act.

e) Please state why it is necessary to retrofit existing intelligent switches in the Smart Community.

RESPONSE:

a) The ten feeders selected for the Smart Community are not the top worst performing feeders in the entire distribution network. However they are the highest concentration of worst performing feeders in the North York district which has the most number of worst performing feeders in the distribution network, as of November 2008 when the Smart Community was first conceptualized. There are no other feeders in the Smart Community.

The current reliability statistics (January 2009 to October 2009) for the Smart Community are as follows:

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Feeder Name	FAIDI	FAIFI	CAIDI
NY35M11	18.12	3.78	4.80
NY35M3	91.52	0.96	95.55
NY35M5	6.87	0.06	122.89
NY85M1	7.96	0.06	129.01
NY85M10	34.86	1.01	34.48
NY85M23	3.97	0.05	82.54
NY85M25	111.31	2.72	40.90
NY85M26	28.88	1.52	19.02
NY85M5	26.21	0.19	140.38
NY85M8	30.72	1.54	19.94

FAIDI: Feeder average interruption duration index
FAIFI: Feeder average interruption frequency index

b) The current reliability statistics for the Smart Community are provided in part a).

c) Current reliability statistics for the Smart Community are below target for 50% of the feeders when compared to the overall distribution system. At the time of selection (November 2008), reliability statistics were below target for 100% of the feeders when compared to the overall distribution system.

d) Prior to the Green Energy Act, reliability improvement of feeders in the Smart Community was considered through actions which would (a) reduce the frequency of outages and (b) reduce the outage impact. Actions to reduce frequency of outages included the following:

- Transformer, cable and other equipment replacement,
- Installation of animal guards and lightning arresters,

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- Increased maintenance and replacement of non-standard components (glass arresters, porcelain insulators, completely self protected transformers, etc.).

Actions to reduce the outage impact included the following:

- System reconfiguration and coordination,
- Installation of switches and fuses to sectionalize feeders,
- Installation of fault current indicators to reduce the fault location time.

e) Existing installed ScadaMate switches are for remote operation only, and not set up for the purpose of automated power restoration. As a result, retrofit is necessary to upgrade the radio communication and switch controller with the enabling "IntelliTEAM" logic to be configured for automated power restoration.

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INTERROGATORY 118:

Reference(s): G1/T1/S2/p 5

On this page, a transformer smart metering project is described.

a) Please state where the smart transformer meters will be located.

b) Please state why smart meters are required, as opposed to using a standard meter and incorporating intelligence in the SCADA system.

c) Please explain how the transformers will be chosen.

d) Please state which functions will be required in the smart meters.

e) Please state what actions will be prompted by these functions.

RESPONSE:

a) Approximately 100 locations have been selected in the North York Smart Community and are located as illustrated in the map below.

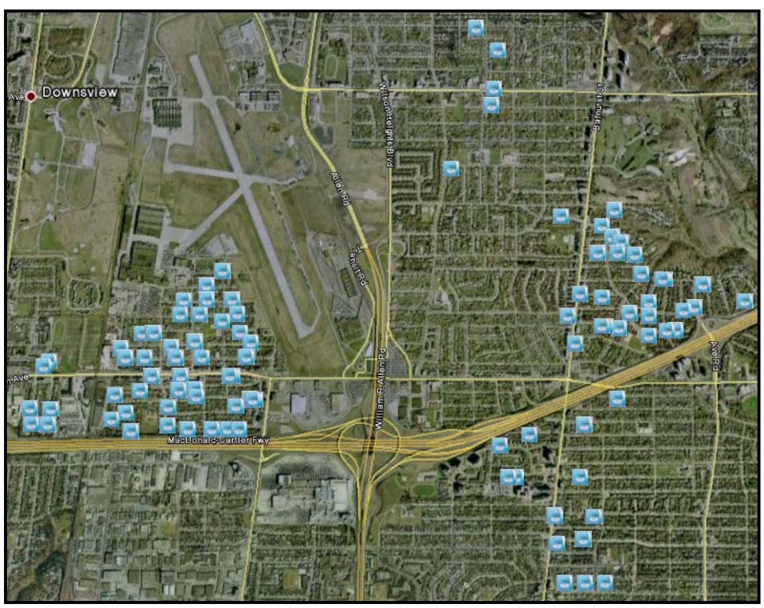

Figure 1: Transformer Smart Meter Locations

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b) Smart meters are required because it is uncommon for standard meters to be tied with SCADA. The smart meters also provide additional functionalities not found on standard meters such as interval metering and last gasp outage reporting. These meters can readily communicate through the existing Advanced Metering Infrastructure ("AMI") via built-in radios, and do not require remote terminal units ("RTUs") necessary for SCADA communications.

By sharing the same smart meter backhaul, their functionalities can then be upgraded with firmware downloads, and the data can be easily integrated into THESL's corporate IT systems. Smart meters are a cost effective and highly functional alternative to standard meters, and can be deployed with greater ease.

c) Transformer would first have to meet the following two criteria:
   (1) Meter proximity – Transformer smart meters would have to be 600 feet apart or less; and
   (2) Transformer type – 120/240 V, 3-wire single-phase transformers ranging from 50 kVA-167 kVA.

A prioritization scheme was then developed to identify transformer locations based on the following parameters:
   (1) Feeder reliability (FAIFI/FAIDI, CI/CMO);
   (2) Reliability hotspots;
   (3) Likelihood of power theft; and
   (4) Potential for transformer overload.

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d) Transformer smart meters utilizes the same metering platform as the smart meters THESL is currently installing for residential customers. They are capable of metering interval energy and demand, provide last gasp outage reporting, report on voltage levels, report on outage statistics, and provide alarms on various exception conditions.

e) The actions that would be prompted by these functions are described in Exhibit G1, Tab 1, Schedule 2, page 5, and would include:

- Integration with the outage management system ("OMS") to enable system operators and field staff with greater system monitoring and troubleshooting capabilities;
- Integration into the Operational Data Store ("ODS") and other enterprise systems to consolidate metering data upstream and downstream at the distribution transformer level, which will be used for loss detection purposes; and
- Decision support for asset management and other key stakeholders when conducting analyses with regards to transformer load management, as well as integration of renewable energy and plug-in electric or hybrid electric vehicles.

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INTERROGATORY 119:

Reference(s): G1/T1/S2/p 7

On this page, a Line Monitoring Project is described.

a) Please state whether all the feeders in the Smart Community are SCADA controlled.
b) Please describe the characteristics of an intelligent switch.
c) Please state how many intelligent switches are in the Smart Community at the present time.
d) Please state how many intelligent switches will be in the Smart Community when the project is implemented.
e) Please state whether it is expected that the 30 power line monitors will be sufficient to allow intelligent switches for all consumers in the Smart Community system.
f) Please state the ultimate number of power line monitors needed for the Smart Community.
g) Please provide a projection of the number of intelligent feeders required for the entire THESL distribution system.
h) Please state where the line monitors will be located.
i) Please state how the locations will be chosen.
j) Please state what actions will be prompted by this project and describe the kind of algorithms which might be used. Please explain how the transformers will be chosen.

RESPONSE:

a) All feeders in the Smart Community are currently SCADA controlled at the substation circuit breaker and at several selected feeder switches, along with other manually operated switches.

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b) An intelligent switch, within the context of the Smart Community, is a switch that has the capability to communicate with the control room and with other intelligent switches within the scheme for information exchange. With a logic programmed into the switch, it is capable of analysing the dynamic conditions of the feeder and operates to isolate the faulty segment and restore healthy segments, without causing an overload condition to alternate feeders.

c) Presently, there are no intelligent switches within the Smart Community.

d) When the project is implemented there will be 40 intelligent switches within the Smart Community.

e) The 30 power line monitors are not necessary for the successful implementation of feeder automation with intelligent switches. Instead they compliment the intelligent switches for better monitoring of network conditions for effective and efficient network operations.

f) Up to 500 power line monitors will be needed for the Smart Community.

g) It is projected that all feeders in the THESL distribution system will be equipped with intelligence. The pace of deployment and level of intelligence will be determined based on the feeder's specific characteristics, including reliability, power quality, renewable energy penetration, plug-in electric and hybrid electric vehicle penetration, and the need to support customer energy management solutions.

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h) The power line monitors will initially be placed along the NY85M5 feeder in the Smart Community, at locations represented in the following map.

Figure 1: Proposed locations for Power Line Monitors on NY85M5

i) The locations for the power line monitors on the selected feeder are chosen based on:

- Circuit topology;

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- Historical outage data and fault locations;
- Customer distribution; and
- Environmental conditions to enable radio communications.

j) The actions that would be prompted by these functions are described in Exhibit G1, Tab 1, Schedule 2, page 7, including:

- Integration with THESL's internal network to equip control room operators with better understanding of real time grid conditions for operational flexibility;
- Integration with the Outage Management System ("OMS") to enable near real-time outage reporting;
- Adjustment of adaptive protection settings (programmable fault indication) to match dynamic feeder configurations and distributed generation penetration levels;
- Monitor the real time impacts of distributed generation and plug-in electric and hybrid electric vehicles as they are introduced;
- Integration with the Operational Data Store ("ODS") and other enterprise systems to consolidate power line monitor data with downstream transformer and consumer smart meters data, for the detection of technical and non-technical losses; and
- Decision support for asset managers to better assess condition and capacity of overhead conductor assets and to better identify outage causes.

The power line monitors are used exclusively for monitoring the operating conditions of overhead conductors in real time. At this stage no algorithms are expected to be used with these devices.

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INTERROGATORY 120:

Reference(s): G1/T1/S2 (pp.10-13)

THESL states that it plans to undertake a number of smart grid related pilots/studies on a variety of topics including plug-in electric vehicles, distributed generation, and home energy portals. Many of these initiatives will be carried out within the proposed North York test zone. Many other LDCs across North America are currently planning and undertaking similar studies. In the Guidelines issued June 16, 2009 the Board stated that if LDCs choose to conduct or commission smart grid pilots/studies they should not duplicate efforts elsewhere in North America and should explore cost sharing partnerships.

a) Individually, for each project please indicate whether THESL has satisfied the requirements for Smart Grid Projects listed on pages 12 and 13 in the Guidelines. And if yes, please state how THESL has done this.
b) Please describe in greater detail the purpose and nature of the proposed studies.
c) Please describe in detail the anticipated benefits of each study.
d) Please state under a scenario where a more concentrated approach were taken:
    i. what three projects are most important and/or unique to THESL's service area; and
    ii. if only these three initiatives were pursued, please provide the comparative cost savings.
e) Please state whether or not THESL plans to purchase electric vehicles.
f) Please provide the proposed geographical boundaries of the pilot area.
g) Please provide a detailed timeline for each study including when THESL expects to be able to report on and apply the lessons learned.

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RESPONSE:

a) THESL has satisfied the requirements for Smart Grid projects listed on pages 12 and 13 of the Board Guidelines on June 16, 2009, by meeting the following requirements: identification of incremental activities, use of prioritization models, avoidance of unnecessary duplication with other work, and neither research- nor development-focused. The initiatives proposed in the reference (Exhibit G1, Tab 1, Schedule 2, pages 10-13) can be summarized in the following four project areas.

(1) Smart Grid Planning Guidelines

Given the novelty and developmental nature of the Smart Grid, THESL must integrate this new requirement into its core asset management and planning processes through planning guidelines. This is necessary to systematically carry out demonstration projects and consider Smart Grid solutions as investment alternatives for system sustainment and expansion, given THESL's unique asset management context. This will allow the identification of crucial efforts to work towards an integrated investment planning system and integrated with the rate application process.

(2) Smart Homes

This initiative has been prioritised with elements in the three-year and three- to ten-year plan of THESL's Smart Grid Roadmap. It is being proposed with the intent of examining the adoption of new technologies and understanding of critical customer responses. THESL has already initiated efforts to work in close partnership with other distributors and industry stakeholders in this project. However, it remains necessary to undertake more study within its own service territory recognising the uniqueness of its customer base.

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(3) Distributed Generation

The integration of distributed generation, in particular renewable generation, has been identified as a key priority in the three-year plan of THESL's Smart Grid Roadmap. THESL will be working in close partnership with other distributors and industry stakeholders in the development of further studies to accommodate a high penetration of distributed generation in the distribution system. However, it remains necessary to study THESL's own unique system recognising the distinctiveness of its electrical network and customer base.

(4) Plug-in Electric or Hybrid Electric Vehicles

As the need for this initiative is driven by market forces THESL has identified the study of PEVs and PHEVs in the three-year plan of THESL's Smart Grid Roadmap. It is anticipated that THESL must undertake efforts to understand the current capacity and potential impacts of PEVs and PHEVs to the network. THESL has initiated work in close partnership with other distributors and industry stakeholders in this project. However, it remains necessary to study THESL's own unique distribution system recognising the distinctiveness of its electrical network and customer base.

b) The purpose and nature of the proposed studies are described in the following.

(1) Smart Grid Planning Guidelines

The purpose of the study is to develop planning guidelines for THESL asset managers, including policy, strategy, long term planning, short term planning, standards, and supply chain requirements. These critical elements need to be

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evaluated and integrated; some of the requirements include the following: (a) understanding of business requirements, (b) sourcing technology solutions, (c) development of guiding policies and strategies, (d) development of methodologies, tools, and processes, and (e) definition of programs and projects.

(2) Smart Homes

The purpose of this study is to understand the application of Smart Grid technologies for energy management and to establish benchmarks for the implementation of customer service programs. Study requirements include the assessment of customer expectations, the identification of possible attitudinal and behavioural barriers for engagement, and the creation of public outreach/information/advertising campaigns. The study consists of a two-part program: (a) qualitative for exploratory purposes and (b) quantitative for confirmatory purposes.

(3) Distributed Generation

The purpose of the study is to assess solutions and develop necessary strategies for the introduction and deployment of large numbers of distributed generation and energy storage, in particular small scale solar. Policy framework, system design, operating procedures, and connection processes will be analysed in order to promote customer acceptance, facilitate connection to the grid, and ensure safety of THESL field staff. Technical and economic feasibility for distributor-owned generation will further be assessed. This study consists of (a) system design and operation, (b) policy framework and customer perception, (c) internal processes, and (c) distributor-owned generation.

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(4) Plug-in Electric or Hybrid Electric Vehicles

The purpose of this study is to analyse the impact, assess solutions, and develop necessary strategies for the connection of large numbers of PEVs/PHEVs into the grid. Given the developmental stage of the market and the potentially substantial impact to electric utilities, it is necessary for THESL to understand the vast implications that PEVs/PHEVs and a charging infrastructure may bring. The studies consists of (a) assessment of system impacts including loading profiles, location impacts, and power quality, (b) requirements related to electrical connection, monitoring, communication, control, billing, and settlement, (c) technology solutions, and (d) strategies for implementation.

c) The anticipated benefits of each study are described in the following.

(1) Smart Grid Planning Guidelines

- Identification of fundamental strategies and policies that will guide the effective development and implementation of THESL's smart grid and distribution plans.
- Identification of solutions to increase effectiveness of internal business units.
- Establishment of tools, methodologies, and best practices with respect to short and long term Smart Grid planning.
- Development of suitable education and training for THESL staff.

(2) Smart Homes

- Development of an in-depth understanding of customer behaviours and value drivers to design effective customer programs for demand response and energy management.

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- Establishment of gaps in current state technologies and development of supporting technology roadmaps.
- Identification of potential opportunities for conservation and energy management.

(3) Distributed Generation

- Identification of critical system infrastructure upgrades and protection and control requirements.
- Establishment of operating procedures and work practices.
- Understanding of customer perception and development of programs to promote customer participation.
- Development of a strategic direction for distributor-owned generation.

(4) Plug-in Electric or Hybrid Electric Vehicle Studies

- Evaluation of potential scenarios, system impacts, and mitigation solutions.
- Identification of metering, communication, billing, and settlement requirements, as well as supporting information technology systems and internal processes.
- Determination of benefits in the areas of system utilisation, customer service, and the environment.
- Assessment of the feasibility of "vehicle-to-grid" model and its operational requirements.

d) All studies identified on Exhibit G1, Tab T1, Schedule 2, pages 10-13 are aligned with requirements of the GEGEA, and are essential as part of the THESL distribution planning process. All of the studies yield valuable results, many of which are unique

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to THESL's electrical network and customer base. Not pursuing any of these projects will hinder THESL's ability to enable distributed generation and the development of the Smart Grid in a timely manner.

In the event that only three studies are to be selected, the following will be pursued:
(1) Smart Grid Planning Guidelines.
(2) Smart Homes.
(3) Distributed Generation.

The proposed projects are studies in nature and thus cost savings have not been calculated if they were to be deployed. However, given the complexity and uniqueness of THESL's system these undertakings present critical opportunities for the connection of distributed generation and the development of the Smart Grid.

e) Pending market availability, THESL is planning to procure PEVs and PHEVs.

f) The proposed projects are studies in nature therefore no designated pilot area is currently being considered at this time. A pilot area will be determined only to meet the requirements of the study and will be defined at the time of the study.

g) THESL anticipates the following timelines for the proposed studies:
   - Smart Grid Planning Guidelines: Q1 2010 – Q3 2010
   - Smart Homes: Q1 2010 – Q3 2010
   - Distributed Generation: Q2 2010 – Q4 2011
   - Plug-in Electric or Hybrid Electric Vehicles: Q3 2010 – Q3 2011

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THESL expects to be able to report on and apply lessons learned following completion of each study.

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INTERROGATORY 121:

Reference(s): **G1/T1/S3**

Based on the project costs provided in Tables 1 to 6, the proposed IT work will cost nearly $ 7 million.

a) In respect of other green energy plans, please state whether the IT expenditures are comparable in terms of percentage of total costs? Please provide a comparison of the percentage of IT expenditure in THESL's Green Energy plan to IT expenditures in other such plans.

b) Please provide a projection of the costs for IT for expansion to the entire distribution system.

c) Please state whether or not there is a way to spread the costs for the Smart Community project over a longer time period.

d) Please state why is this considered to be a "smart" application.

RESPONSE:

a) The current embryonic state of Smart Grid technologies does not provide readily comparable benchmarks for assessment. Instead, THESL has engaged a major consulting firm, with significant North American and global experience in the field, to help in creating a high-level IT Smart Grid plan that aligns with the strategic direction.

The Smart Grid IT Strategy has developed a Roadmap and established projects and estimates to support the business requirements using Smart Grid technology. These costs have been used as the THESL estimates for IT spending on Smart Grid beginning in 2010.

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A higher initial outlay will account for IT infrastructure costs to provide enablement to technologies that are in support of the Smart Grid pilots. Some of the IT technologies are foundational and will incur an upfront cost such as building an accessible communications network with greater speed, bandwidth and reliability. Due to the extensive data that smart grid devices will produce, a secure method is required to collect and store information. Mechanisms such as encryption, firewalling and device identity verification will need to be deployed to ensure protection of the grid. Repositories will be required to house the data, applications to make use of the data, servers to host the applications and associated middleware and interfaces built to integrate the data with legacy systems. Although much of the costs outlined is deployment in nature, an initial investment is also accounted for architecting and designing the solution.

b) Please refer to Exhibit R1, Tab 1, Schedule 107, Table 6 for the estimated IT costs to support the implementation of the Smart Grid operation activities beginning in the test year of 2010 through 2012. Estimates for the years beyond 2010 will be reassessed as the program unfolds. This forecast assumes successful demonstration of the initiatives and that projects move into a deployment phase.

c) The proposed plan for the Smart Grid pilots in 2010 is in keeping with the Provincial mandate to progress Smart Grid and Distributed Generation forward. THESL's size and position in the industry provides both an opportunity and obligation to lead in a measured and sustainable way, and THESL's proposed plan reflects the required pace and amounts to do so.

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Spreading the costs of the Smart Grid Community over a longer time period would introduce unnecessary and preventable risks. For example:

1) It is important to appreciate that Smart Grid will inherently increase the potential for malicious or inadvertent security threats as more lines of communications are introduced between homes, the Corporate network and the SCADA network, as well as within the SCADA network itself. A significant portion of the requested funding is, therefore, dedicated for studies necessary to ensure a proper architectural design of the grid security in response to that inherent risk. Slowing the pace of these studies will actually heighten the potential security risks to the grid.
2) It may jeopardize THESL's ability to handle the projected increase in Distributed Generation connections.
3) It will slow THESL's ability to handle the projected grid load caused by electric vehicles, potentially risking the stability of the grid.

d) The Smart Community is the pilot stage for several aspects of the Smart Grid initiative. Technologies will be initially implemented in North York, across a demonstration area including 25,000 customers. As shown in Table 1 above, the program has been planned to establish pilot projects during 2010 that set the foundation for the Implementation projects which follow beginning in 2011. Information gained from these demonstrations would be shared via the Board's Repository of project reports and the Ontario Smart Grid Forum.

These pilot projects will also ensure that the benefits of the Smart Grid applications can be delivered, that THESL understands the risks going forward, and that THESL

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can share the discovered information via the Board's repository of demonstrated projects to other distributors across the province.