

RP-2007-0706

Enersource Mississauga Hydro Inc.

November 12, 2007

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Board Staff Interrogatories

Interrogatory

#1 - Ref: Exhibit C/ Schedule 3/ Tab 3

a. Does ‘Land’ in this table refer to acquisition of land for a parking lot, as identified in the note on Exhibit C Schedule 3 Tab 7 p2?

b. Please provide details of the need for, and the cost-benefit study for the \$2.5 million capital expenditure for Land.

c. Please provide, for each of the years from 2002 through the present, the inventory for each category of “rolling stock and equipment”, and where there is an increase please provide an explanation and justification for the increase, including any changes in policy.

Response

a. Yes. The property being purchased is adjacent to the Land and Building at 3240 Mavis Road.

b. The property is being purchased in order to accommodate the growing workforce requirements of Enersource. A cost-benefit study was not conducted due to the nature of the purchase. Enersource believes this to be an infrastructure investment that is necessary and not optional due to fact that Enersource does not have enough parking spaces for its’ employees. 3240 Mavis Road has 291 employee parking spaces and 22 visitors’ spaces. Inability to purchase this property will result in the need for a satellite location that will be more expensive and disruptive to the organization.

c. The increases and decreases are based on the vintage, asset condition and business needs.

Fleet requirements are based on replacement requirements, work program and staff levels. Please see Exhibit C/Schedule 5/Tab 1/Page 64 of 68.

Reference Exhibit C/Schedule 3/Tab 3

Rolling Stock Inventory	2002	2003	2004	2005	2006	2007 Bridge	2008 TEST
4 year life	11	11	13	13	14	14	14
5 year life	55	57	60	66	68	64	64
8 year life	107	106	109	111	115	114	114
Total units(as of)	173	174	182	190	197	192	192

Interrogatory

#2 - Ref: Exhibit C/ Schedule 3/ Tab 4

Please revise the table titled “2008 Capital expenditures” so that the amounts related to Smart Meters are clearly identified in the categories of “Metering & Customer Additions” and “Wholesale Metering” and other categories in which there might be a component relating to Smart Meters.

Response

The 2008 Capital Expenditures do not include any component that relate to Smart Meters for residential, small commercial and general service customers. All smart meter related capital expenditures pertaining to the replacement of conventional meters are included in the Smart Meter Rate Adder.

Interrogatory

#3 - Ref: EHM – Project Business Cases/ Sec 3.3/ page 47 of 68

Underground Cable and Splice Replacement is indicated as the highest and second highest causes of customer outage time.

- a. Please indicate if the replacement of cable and splices is on a planned basis or on an “as-required basis”**
- b. If on a planned basis, has an audit or asset assessment process been used, and if so please provide details of the process?**
- c. Is the replacement/rehabilitation activity for cables and splices appropriate (excessive or insufficient) in the light of reliability indices?**
- d. Please provide information on the process for and reliability of the cable rehabilitation process and why cable might not be amenable to replacement.**
- e. Cable Replacement is also mentioned as an item under Subdivision rebuilds, on page 40 of 68. How is this distinguished from the Underground Cable Replacement on page 47.**

Response

- a. Both cable and splices are replaced on an “as required basis” as well as on a planned basis. All replacements are performed to maintain optimum reliability.
- b. For any planned replacements, Enersource considers the age of the plant and the reliability history as well as the impact of continued failures relative to replacement costs.
- c. To the best of our knowledge, Enersource's reliability indices compare favourably with that of other similar LDCs. Since cable and splice failure continues to account for a significant amount of our customer outage time, we ensure that an appropriate portion of our capital budget is committed to this activity.
- d. Rehabilitation is a process where a fluid is injected through the core of the conductor. This fluid reacts with the insulation of the cable to strengthen it and reduce the risk of cable failures. The service provider will refund a portion of the cost if a subsequent cable failure occurs. The service costs approximately 50% of cable replacement costs and is intended to extend the life of the cable by approximately 20 years. Enersource has used this process for cables where the core conductor is stranded and, therefore, can be injected. It has been somewhat successful but we do not have reliability statistics at this time.

The cable with the largest population and also the highest failure rate on the Enersource system is a solid core conductor, which cannot be injected. In this case, replacement is our only option. The reliability for replacement cables is extremely high and current technology could result in a 40 year life. One could say that cables are not “amenable” to replacement if the replacement cost is significant. In this case, we may wait until absolutely necessary to replace the cable. Replacement cost might be high for a particular area due to unfavourable soil conditions such as shale.

e. Non-Subdivision rebuild cable replacements are done on an as required basis and are generally smaller in scope. Typically, this sort of underground cable replacement involves a single section, or a portion of a section of cable.

Cable replacements for Subdivision rebuilds are on a planned basis and are larger in scope. Typically, a Subdivision rebuild involves the replacement of several sections of cable, or cable for an entire subdivision.

Interrogatory

#4 - Ref: Exhibit D, Schedule 2, Tab 8.1

- a. What is the life (in years) and depreciation rate for Substation and other distribution transformers?**
- b. Are transformers included in the other “Municipal Distribution Equipment”, and is this appropriate?**
- c. Revise the table to identify the depreciation for transformers**

Response

- a. The expected life and depreciation rate for Substation and other distribution transformers is set out in Exhibit D/ Schedule 2/ Tab 8.1.
- b. Power Transformers are part of Asset Class B, Municipal Substation Distribution Equipment. The expected useful life for these transformers is 30 years, hence it is appropriate to include them as part of Substation Equipment.
- c. Please see Exhibit D/ Schedule 2/ Tab 8.1 which identifies the life and depreciation of power transformers.

Interrogatory

#5 - Ref: System Capacity Report, prepared September 2006/ (pages 513-618)

- a. Has a System Capacity Report been produced in 2007, similar to that produced in September 2006 and provided at page 513 of the Application?**
- b. If so, please provide the updated report.**

Response

[Please refer to attached System Capacity Report 2008.](#)

Interrogatory

#6 - Ref: Exhibit C/Schedule 3/Tab 3

Please provide a similar table to the reference, or expand the table in the reference, to show the Schedule of Capital Additions for 2006 Actual compared with the 2007 Budget year.

Response

**Enersource Hydro Mississauga
Schedule of Capital Additions
2007 Budget Year and 2006 Actual**

	<u>2007 Budget Year</u>	<u>2006 Actual</u>
LAND	-	-
BUILDINGS-BRICK	-	510,144
SUBSTATION EQUIPMENT	2,875,000	3,437,399
SUPERVISORY CONTROL EQUIPT.	1,370,000	1,595,467
O/H PRIMARY	9,125,000	9,524,650
U/G PRIMARY	15,175,000	14,690,089
METERS	1,115,895	1,456,225
GENERAL OFFICE EQUIPMENT	2,110,000	1,074,628
ROLLING STOCK & EQUIPMENT - 4 YR. LIFE	465,500	106,275
ROLLING STOCK & EQUIPMENT - 5 YR. LIFE	931,000	498,321
ROLLING STOCK & EQUIPMENT - 8 YR. LIFE	465,500	961,908
GARAGE EQUIPMENT	300,000	-
MAJOR TOOLS & INSTR.	150,000	202,423
COMPUTER EQUIPMENT	6,395,000	1,481,780
SOFTWARE	1,088,000	1,918,024
	<u>41,565,895</u>	<u>37,457,335</u>

Interrogatory

#7 - Ref Exhibit C/p513/ System Capacity Report

Please provide an updated table showing actual or projected connections to residential, commercial and industrial customers for the historic, bridge and test years

Response

Year	# of Connections for Commercial/Industrial Customers		
	Actual to Sept2007	Estimate for rest of year	Total
2006	530	not applicable	530
2007	360	140	500
2008	0	500	500

*

*Note:

The estimate of 2007 total annual commercial/industrial connections has been revised from 535 to 500.

Year	# of Connections for Residential Customers			
	All Connections	Apartment/Condominiums	Standard Residential	All Connections
	Actual to Sept2007	Estimate for rest of year		Annual Total
2006	3447	not applicable	not applicable	3447
2007	1611	1228	650	3489
2008	not applicable	2800	2000	4800

**

**

**Notes:

- 1.The actual number for 2006 for residential connections has been revised from 3500 to 3447.
- 2.The estimate of 2007 total annual residential connections has been revised from 4000 to 3489.
- 3.Although not seen in this table, the actual number for 2005 for residential connections has been revised from 2900 to 2400.

Interrogatory

#8 - Ref: Filing Guidelines s2.3 and Exhibit C schedule 3 Tab 7 p1,2

a. Please provide written explanations for all rate base information where the cost is greater than or equal to 1% of fixed assts.

b. Please revise the tables at Exhibit C schedule 3 Tab 7 p1,2 to include columns for the Historical Board Approved 2006 and the Historical Actual, also for 2006.

Response

- a) Written explanations were provided for each summarized USoA account in Exhibit C/ Schedule 3/ Tab 7/ pages 1 and 2. A variance analysis with written explanations for rate base information where cost is greater than or equal to 1% is as follows:

	<u>Test 2008</u>	<u>Bridge 2007</u>	<u>Variance</u>
<u>Property, Plant & Equipment</u>			
Asset Value at Cost	792,787	755,691	37,096
Less: Construction Work In Progress	(5,182)	(9,182)	4,000
Accumulated Depreciation	(378,678)	(350,221)	(28,457)
Net Fixed Assets (Average of Opening & Closing)	408,928	396,287	12,639
<u>Allowance for Working Capital</u>			
TOTAL COST OF POWER	601,101	564,470	36,631
TOTAL EXPENSES (excluding Depreciation)	42,076	41,889	187
Total for consideration of Working Cash Allowance	643,177	606,359	36,818
15% for Working cash Allowance	96,477	90,954	5,523
RATE BASE	505,404	487,242	18,162

	<u>Test 2008</u>	<u>Bridge 2007</u>	<u>Variance</u>	<u>Variance</u> <u>%</u>
Land and Buildings	19,882	18,639	1,243	0.3%
Distribution System	67,941	65,898	2,043	0.5%
Poles, Wires	593,896	565,674	28,222	6.9%
Line Transformers	67,654	68,539	(885)	-0.2%
Services and Meters	36,762			0.5%

Equipment	27,269	34,731 23,233	2,031 4,036	1.0%
IT Assets	13,208	8,442	4,766	1.2%
Other Distribution Assets	14,852	14,112	740	0.2%
	841,464	799,268	42,196	10.3%
Contributions and Grants	(53,858)	(52,760)	(1,098)	-0.3%
Construction In Progress	5,182	9,182	(4,000)	-1.0%
	792,788	755,690	37,098	9.1%
<u>Less</u>				
Construction In Progress	(5,182)	(9,182)	4,000	
Accumulated Amortization	(378,678)	(350,221)	(28,457)	
	(383,860)	(359,403)	(24,457)	
	408,928	396,287	12,641	

Variance Explanation (Cost Greater Than 1% of Net Fixed Assets)

	<u>Test 2008</u>	<u>Bridge 2007</u>	<u>Variance</u>	<u>Variance %</u>
<u>Poles, Wires</u>	593,896	565,674	28,222	6.9%

The increase in Poles, Wires of \$28.2 M (5.0%) in the 2008 Test Year over the 2007 Bridge Year is driven by three major categories of investments as outlined and detailed below:

Poles, Wires are classified as three major investments.

- *System Capacity - Growth Driven Investment*
- *System Maintenance - Reliability Driven Investment*
- *System Expansion & Upgrades - Customer Driven Investment*

The Table below depicts average annual investments in Poles, Wires of \$28.2 million over the 2008 Test Year and 2007 Bridge Year net of retirements.

<u>System Capacity - Growth Driven Investment</u>	<u>Test 2008</u>	<u>Bridge 2007</u>	<u>Average 2 yrs</u>
New Sub transmission/Distribution Construction	5,850	5,850	5,850
	5,850	5,850	5,850
<u>System Maintenance - Reliability Driven Investment</u>			
Subdivision Rebuilds	6,100	5,950	6,025
Overhead Distribution Upgrades	2,600	2,525	2,563
Underground Distribution Maintenance	2,200	2,125	2,163
Transformer Replacement	650	600	625
Construction in Progress Transfer Fixed Assets	-	3,282	1,641
	11,550	14,482	13,016
<u>System Expansion & Upgrades - Customer Driven Investment</u>			
New Industrial/Commercial Customer Services	4,200	4,000	4,100
New Subdivisions	2,575	2,500	2,538

Road Projects	750	750	750
Contribution In Aid of Construction	3,750	4,000	3,875
	11,275	11,250	11,263
Gross Capital Spending	28,675	31,582	30,129
Retirements	(2,665)	(1,149)	(1,907)
Net Capital Spending	26,010	30,433	28,221

New Sub transmission/Distribution Construction

Included in Poles, Wires is the capital spending for New Sub transmission/Distribution Construction for 2008 and 2007. New Sub transmission/Distribution Construction is a system capacity growth driven investment that is also driven by customer load growth and attributes to increase system capacity and reliability.

The requirement for new distribution infrastructure is also driven by increased electrical load new commercial and residential customers and upgrades to the distribution system in order to minimize customer outages as a result of equipment failure.

In light of the above, Enersource has invested significantly over the years in System Maintenance - Reliability Driven Investments and these account for approximately 26% of our capital budget spending in the 2008 Test Year and 2007 Bridge Year respectively.

System Maintenance Investments

System maintenance investments are required to preserve the condition of the distribution system and minimize customer outage risks. These investments chosen based on system performance and specific projects are based on equipment that has experienced Interruption frequencies beyond acceptable levels due to age or excessive equipment deterioration.

System Expansion Upgrades

New Industrial/Commercial Customer Services that provides for service installation and upgrades for industrial and commercial customers.

New Subdivisions that provides for capital contributions required under Section 3 of the Distribution System Code for development of new electrical infrastructure installed in the new subdivisions including single lots and apartment buildings.

	<u>Test 2008</u>	<u>Bridge 2007</u>	<u>Variance</u>	<u>Variance</u> <u>%</u>
Equipment	27,269	23,233	4,036	1.0%

The increase in Equipment is principally of \$4.0 M (17.4%) net of retirement is principally due to Rolling Stock of \$1.9 M and General Office Equipment of \$2.1 M.

	<u>Test 2008</u>	<u>Bridge 2007</u>	<u>Variance</u>	<u>Variance</u> <u>%</u>
IT Assets	13,208	8,442	4,766	1.2%

The increase in IT assets of \$4.8 M (56.5%) in principally due to the acquisition of the New Customer Information System, which was projected to cost approximately \$8.0 M over a two year period and has been revised to \$10.8M.

b)

Enersource Hydro Mississauga
Property, Plant & Equipment
Variance Analysis

Note: all amounts in \$ 000's

Distribution Assets Rate Base

	<u>2008 Test Year</u>	<u>2007 Bridge Year</u>	<u>Actual 2006</u>	<u>2006 EDR</u>
<u>Property, Plant & Equipment</u>				
Asset Value at Cost	\$ 792,787	\$ 755,690	\$ 721,665	\$ 667,211
Less: Construction Work In Progress	(5,182)	(9,182)	(8,464)	-
Accumulated Depreciation	(378,678)	(350,221)	(324,439)	(278,088)
Net Fixed Assets (2 yr average)	\$ 408,927	\$ 396,287	\$ 388,762	\$ 389,123
<u>Allowance for Working Capital</u>				
TOTAL COST OF POWER	601,101	564,470	557,590	539,291
TOTAL EXPENSES (excluding Depreciation)	42,076	41,889	35,461	32,633
Total for consideration of Working Cash Allowance	\$ 643,177	\$ 606,359	\$ 593,051	\$ 571,924
15% for Working cash Allowance	96,477	90,954	88,958	85,789
RATE BASE	\$ 505,404	\$ 487,241	\$ 477,720	\$ 474,912

	<u>Test 2008</u>	<u>Bridge 2007</u>	<u>Actual 2006</u>	<u>2006 EDR</u>
Land and Buildings	\$ 19,882	\$ 18,639	\$ 18,392	\$ 17,216
Distribution System	67,941	65,898	63,673	59,279
Poles, Wires	593,896	565,674	539,021	488,408
Line Transformers	67,654	68,539	69,342	69,807
Services and Meters	36,762	34,731	32,976	31,196
Equipment	27,269	23,233	20,511	17,041
IT Assets	13,208	8,442	6,726	9,300
CDM Assets	-	-	-	2,793
Other Distribution Assets	14,852	14,112	14,488	14,401
	841,464	799,268	765,128	709,441
Contributions and Grants	(53,858)	(52,760)	(51,926)	(42,230)
Construction In Progress (see note on CIP)	5,182	9,182	8,464	-
	\$ 792,788	\$ 755,690	\$ 721,665	\$ 667,211
Less				
Construction In Progress (see note on CIP)	(5,182)	(9,182)	(8,464)	-
Accumulated Amortization	(378,678)	(350,221)	(324,439)	(278,088)
	\$ (383,860)	\$ (359,403)	\$ (332,903)	\$ (278,088)
	\$ 408,928	\$ 396,287	\$ 388,762	\$ 389,123

Interrogatory

#9 - Ref: System Capacity Report

For each of the capital addition projects please provide starting dates and in-service dates.

Response

The capital budgeting process begins with the completion of a System Capacity Report. In this report, Enersource determines the areas of the City where the distribution system infrastructure must be replaced and the areas where additional capacity will require new infrastructure. System performance (addressing reliability and age issues) drives replacement planning. Load growth drives new investment planning.

The actual in-service dates of projects listed in the System Capacity Report will differ from the estimated in-service dates listed below because of a variety of factors beyond the control of Enersource Hydro. For example, there may be changes in work scope, delays in materials, reliability upgrades that become mandatory that were deemed discretionary as well as potential third party influence. Enersource uses work breakdown structure to track project expenditures and the status of each project. Once the work orders have been “energized”, projects are deemed to be in-service. Please see the below for the estimated/forecasted in-service dates of the projects listed in the 2007 System Capacity Report (Exhibit C/ Schedule 4/Tab1) and the 2008 System Capacity Report (response to SEC interrogatory #27).

Project Name	2007 Q1	2007 Q2	2007 Q3	2007 Q4
Subtransmission/ Distribution				
4 - 27.6kV Derry Rd - Crossing Hwy 410	S			F
4 cktS - Derry Rd - Bramalea Rd to Columbus				
27.6 & 4.16kV - Hurontario, QEW to Mineola	S			F
44kV - C5M27 extension to Confederation MS	S			F
2-44kV - Erindale TS to Britannia Rd / Creditview	S	F		
2-27.6kV feeders in ROW - Hwy 403 to Eglinton				
2- 13.8kV & 2-44kV Ninth Line - Eglinton to TACC	S			F
44kV - Britannia Rd - Creditview to Miss . Rd	S	F		
13.8kV Ninth Line - Britannia to Derry	S	F		
44kV - 74M49 extension from Bramalea TS to Drew Rd				

Project Name	2007	2008 Q1	2008 Q2	2008 Q3	2008 Q4
Subtransmission/ Distribution					
44kV - Cawthra Rd - Dundas St to Bloor MS		S	F		
3 - 8/ 13.8kV - Chinook Ph 1		S			F
44kV - Meadowvale TS Feeder Relief - TS to WCB & the railway tracks		S			F
44kV - Bramalea TS Feeder Relief - 74M49 CB to Bramalea Rd to Drew Rd		S			F
44kV - Winston TS Egress Feeders Ph 1 - Ninth Line to WCB		S			F
16/ 27.6kV - WCB - Royal Windsor to Lakeshore then to Avonhead		S	F		
8/ 13.8kV - Etude - Goreway to Cambrett Dr		S	F		
Total Subtransmission/Distribution					
SUBDIVISION REBUILDS					
Inverhouse		S			F
Winwood Drive		S			F
Pheasant Run		S			F
Council Ring Phase II		S			F
Falconer Drive		S			F
Misc.		S			F
Total Subdivision Rebuilds					
SUBSTATIONS					
Confederation MS - add tx, cabling		S	F		
New # 90 at WCB/ Hwy 401		S			
Bromsgrove MS - reclosures & automation		S			F
Protection Relays - McNeice		S			F
Protection Relays - Melton		S			F
Bexhill MS upgrade		S			F
Century T2 - add tx & new HV breaker	S				F
Grossbeak T2 - new tx & HV breaker	S				F
Spare offload tx	S				F
Substation Site Enhancements		S			F
AUTOMATED SWITCHES AND SCADA					
Automation at various MS's		S			F
Automation at various feeders		S			F
Total Automation					
SYSTEM MAINTENANCE PROJECTS					
Wood & Concrete Pole Replacement (100)		S			F
Overhead Switch and Insulator Replacement (100)		S			F
Feeder Overhaul (3)		S			F
Overhead Rebuild (350 homes)		S			F
Primary Distribution Equipment Replacement		S			F

Underground Cable and Splice Replacement	S	F
Meter Base Replacements	S	F
Secondary Cable Replacements	S	F
Underground Transformer Replacement (40)	S	F
Overhead Transformer Replacement (45)	S	F
Total System Maintenance		
OTHER CAPITAL		
ROAD PROJECTS	S	F
New Industrial/Commercial Customers	S	F
New Subdivisions	S	F
MAJOR TOOLS	S	F
ROLLING STOCK	S	F

Note:

S – Represents the estimated start date

F – Represents the estimated in-service date

Interrogatory

#10 - Ref: None:

Please confirm if Enersource has any leave to construct projects which require an application under the section 92 of the Ontario Energy Board Act requirement, as part of this application.

Response

Enersource confirms that it does not anticipate seeking an order of the Board granting leave to construct in 2008.

Interrogatory

#11 - Ref: Filing Guidelines s2.3:

Please provide written explanations for all rate base information where the variance between the Historical Board Approved for 2006 and the Historical Actual, also for 2006 (as listed in the tables in Exhibit C schedule 3 Tab 7 p1, 2 and revised per Board Staff Interrogatory 8 (b) above, is greater than or equal to 1% of the total fixed assets

Response

Property, Plant & Equipment

Variance Analysis (1% of NFA) - 2006 EDR vs. 2006 Actual

\$000s

Distribution Assets Rate Base

	<u>Actual 2006</u>	<u>EDR 2006</u>	<u>Variance</u>
<u>Property, Plant & Equipment</u>			
Asset Value at Cost	721,665	667,211	54,454
Less: Construction Work In Progress	(8,464)	-	(8,464)
Accumulated Depreciation	(324,439)	(278,088)	(46,351)
Net Fixed Assets (2 yr average)	388,762	389,123	(361)
<u>Allowance for Working Capital</u>			
TOTAL COST OF POWER	557,590	539,291	18,299
TOTAL EXPENSES (excluding Depreciation)	35,461	32,633	2,828
Total for consideration of Working Cash Allowance	593,051	571,924	21,127
15% for Working cash Allowance	88,958	85,789	3,169
RATE BASE	477,720	474,912	2,808

	<u>Actual 2006</u>	<u>EDR 2006</u>	<u>Variance</u>	<u>Variance %</u>
Land and Buildings	18,392	17,216	1,176	0.3%
Distribution System	63,673	59,279	4,394	1.1%
Poles, Wires	539,021	488,408	50,613	13.0%
Line Transformers	69,342	69,807	(465)	-0.1%
Services and Meters	32,976	31,196	1,780	0.5%
Equipment	20,511	17,041	3,470	0.9%
IT Assets	6,726	9,300	(2,575)	-0.7%
CDM Assets	-	2,793	(2,793)	-0.7%
Other Distribution Assets	14,488	14,401	87	0.0%

	765,128	709,441	55,687	14.3%
Contributions and Grants	(51,926)	(42,230)	(9,696)	-2.5%
Construction In Progress	8,464	-	8,464	2.2%
	721,665	667,211	54,454	14.0%
<u>Less</u>				
Construction In Progress	(8,464)	-	(8,464)	
Accumulated Amortization	(324,439)	(278,088)	(46,351)	
	(332,903)	(278,088)	(54,815)	
	388,762	389,123	(361)	

Variance Explanation (Cost Greater Than 1% of Net Fixed Assets)

The increase in the Distribution System and Poles, & Wires is driven by two years of capital growth as the 2006 EDR was based on 2004 actuals.

Interrogatory

#12 - Ref: Filing Guidelines s2.3:

For Accumulated Depreciation please provide, for the Historic Actual, Bridge and Test years:

- a. A summary and breakdown by asset account;**
- b. A detailed calculation of the depreciation amount of each account indicating the years over which depreciation occurs;**
- c. Continuity statements by asset account, which should be reconcilable to calculated depreciation costs and presented by asset account.**

Response

- a. Please see the attached spreadsheet.
- b. The depreciation rates are provided in Exhibit D / Schedule 2 / Tab 8.1. A detailed calculation is included in the continuity schedules provide in part c.
- c. Please see attached spreadsheets for 2006, 2007, and 2008.

Interrogatory

#13 - Ref: Filing Guidelines s2.3 item 3 (Allowances for Working Capital) and Exhibit C Schedule 3 tab 5

- a. State whether a 15% formula is being used for O&M accounts, and
- b. Provide the calculation for each account.
Where 15% is not being used for Allowance for Working Capital, provide a detailed calculation (including the calculation of the average of the opening and closing year balances) for each of the Historic Actual, Bridge and Test years, for:
 - c. Supplies and Materials,
 - d. Prepaid expenses,
 - e. Miscellaneous accounts receivable,
 - f. Working cash allowance (Test year),
 - g. Security Deposits; and
 - h. Other items itemized individually.

Response

- a) Yes.
- b) 15% was used, please see Exhibit A / Schedule 12 / Tab 7.
- c) to h) Not applicable

Interrogatory

#14 Ref: Exhibit C

For each of the years 2002 through 2008 please provide the following listing actual dollars in years where available (and if not then using expected or planned or projected), or percentages as indicated.

Response

(\$000's)	Historic					Bridge	Test
	2002	2003	2004	2005	2006	2007	2008
Net Income	15,027	9,973	10,490	12,779	13,301	10,230	18,195
Approved Return on Equity (%)	9.88%	9.88%	9.88%	9.88%	9.00%	9.00%	9.00%
Actual Return on Equity (%)	9.27%	5.63%	5.61%	7.43%	7.46%	5.60%	NA
Retained Earnings	21,529	31,502	16,250	22,735	27,136	28,466	37,761
Dividends to Shareholders	-	-	25,742	6,294	8,900	8,900	8,900
System Capacity - Growth driven Investment	5,109	6,007	7,891	8,579	8,121	8,725	9,275
System Maintenance - Reliability Driven investment	8,424	9,676	8,067	9,362	12,018	12,570	12,950
System Expansion & Upgrades - Customer Driven investment	6,537	6,599	8,149	7,833	8,521	8,089	8,414
Non-System requirements - Regulatory driven investments	-	-	269	1,147	2,023	2,500	1,120
Non-System requirements - Internally driven investments	8,421	3,730	5,538	5,539	5,834	11,604	12,836
Sustainment Cap Ex	NA	NA	NA	NA	NA	NA	NA
Development Cap Ex	NA	NA	NA	NA	NA	NA	NA
Operations Cap Ex	NA	NA	NA	NA	NA	NA	NA
Other Cap Ex (Specify)	NA	NA	NA	NA	NA	NA	NA
Total Net Cap Ex	28,491	26,012	29,914	32,460	36,517	43,488	44,595
Depreciation	25,825	27,533	29,321	29,766	30,275	32,007	34,357

Interrogatory

#15 - Ref: Exhibit A/ Schedule 13/ Tab 1/ page 2

**At Exhibit A/Schedule 13/Tab 1/page 2, the applicant states:
“Enersource has elected to rely on the three year actual weighted
average monthly price for 2004-2006 to forecast the Cost of Power”.**

a. Please provide a table showing Enersource’s:

I) Actual Cost of Power (years 2002-2006),

II) Weather-corrected Cost of Power (years 2002-2006) and

**III) Bridge year (2007) and Forecast year (2008) forecasted Cost
of Power,**

**b. Please explain in detail the reasons why Enersource has used a
simple historical average to provide a forecast for this component.**

**c. Provide an alternative Cost of Power forecast for the years 2007and 2008
utilizing the change in Cost of Power that Enersource has experienced over
time (e.g. a trend rather than a 3-year average), and explain the rationale
used in establishing these new values.**

Response

a) I.

Actual Cost of Power for 2002 – 2006 (000’s)

Year	2006	2005	2004	2003	2002
Actual Cost of Power	557,271	672,412	534,046	536,959	566,333

a) II.

Enersource budgets based on normalized costs of power, as detailed in the Short Term Load Forecast in Exhibit B/ Schedule 3/ Tab2. Due to the nature and complexity of recalculating customer cost of power, Enersource is unable to provide the requested information.

a) III.

Forecast Cost of Power for 2007 – 2008 (000’s)

Year	2008	2007

Forecast Cost of Power	601,101	564,470

b. As stated in Exhibit A/ Schedule 13/ Tab 1, Enersource elected to rely on the three year actual weighted average monthly price for 2004-2006 to forecast the Cost of Power as the resultant amount of 5.8 cents was consistent with the forecast cost of power prepared by Navigant Consulting in its April 12, 2007 presentation to the Ontario Energy Board and was used to support the Board's work in setting the Regulated Price Plan.

c. Enersource cannot predict the cost of power and as such relied on a three year actual weighted average monthly price for 2004-2006 which aligned with the forecast cost of power prepared by Navigant Consulting in its April 12, 2007 presentation to the Ontario Energy Board.

Interrogatory

#16 - Ref: Exhibit B/ Schedule 2/Tab 1/page 1; Exhibit B/ Schedule 2/Tab 2/ page 1& 2; Exhibit B/ Schedule 2/Tab 3/page 1; Exhibit B/ Schedule 2/Tab 5a; Exhibit B/ Schedule 2/Tab 5b; Exhibit B/ Schedule 2/Tab 6

Please re-file the tables listed above and:

- a. Include historical data for the years 2002-2006 and, provide for these years, (i) actual data and (ii) weather normalized data (where appropriate), and
- b. Identify the data values that incorporate the effects of the Applicant's CDM programs.

Response

Historical data for 2006 is provided in the original reference schedules. Historical actuals for 2002 – 2005 is provided below.

a.(i)

RATE CLASS	Average Number of Customers (Connections)			
	2006 EDR	2006 EDR	2006 EDR	2005
	2002	2003	2004	
	#	#	#	
Residential	146,914	153,732	154,721	157,564
Less than 50 kW	15,240	15,647	15,848	15,705
Small Commercial (Flat Rate)	2,274	3,691	3,158	3,370
GS 50-499 kW	3,832	3,838	3,903	3,995
GS 500-4999 kW	374	400	409	435
Large User	10	10	9	8
Street Lighting	45,405	46,530	47,027	47,514
TOTALS	214,049	223,848	225,075	228,591

RATE CLASS	Demand Data - kWh (excluding Losses)			
	2006 EDR	2006 EDR	2006 EDR	2005
	2002	2003	2004	
	kWh	kWh	kWh	
Residential	1,526,339,987	1,466,049,709	1,430,200,622	1,639,912,499
Less than 50 kW	713,227,471	675,730,581	649,135,821	675,984,015
Small Commercial	18,709,065	17,302,786	11,706,292	12,180,789

GS 50-499 kW	2,376,175,100	2,645,039,373	2,251,423,078	2,407,539,242
GS 500-4999 kW	1,713,391,934	1,513,807,682	2,085,767,680	2,291,688,553
Large User	938,466,140	982,222,680	976,241,486	966,642,280
Street Lighting	37,969,969	35,826,297	36,486,304	37,770,372
TOTALS	7,324,279,666	7,335,979,108	7,440,961,283	8,031,717,750

Average kWh / customer connection			
2002 kWh	2003 kWh	2004 kWh	2005 kWh
10,389	9,536	9,244	10,408
46,800	43,186	40,960	43,043
8,227	4,688	3,707	3,614
620,087	689,171	576,844	602,638
4,581,262	3,784,519	5,099,676	5,268,250
93,846,614	98,222,268	108,471,276	120,830,285
836	770	776	795
99,114,216	102,754,139	114,202,484	126,759,033

RATE CLASS	kW (excluding Transformer Ownership)			
	2006 EDR	2006 EDR	2006 EDR	2005
	2002 kW	2003 kW	2004 kW	
GS 50-499 kW	6,863,255	6,313,615	6,385,580	6,581,476
GS 500-4999 kW	4,878,753	4,709,720	4,880,853	5,081,621
Large User	1,691,529	1,654,554	1,633,244	1,612,869
Street Lighting	109,512	104,728	105,299	108,179
TOTALS	13,543,049	12,782,617	13,004,976	13,384,145

RATE CLASS	Transformer Ownership kW			
	2006 EDR	2006 EDR	2006 EDR	2005
	2002 kW	2003 kW	2004 kW	
Less than 50 kW			-	876
GS 50-499 kW	650,563	729,050	459,258	473,500
GS 500-4999 kW	2,192,290	1,967,340	2,537,925	2,577,019
Large User	1,615,740	1,668,385	1,633,750	1,617,758

TOTALS	4,458,593	4,364,775	4,630,933	4,669,153

OTHER REVENUE

(000's)

	2002	2003	2004	2005
	ACTUAL	ACTUAL	ACTUAL	ACTUAL
LATE PAYMENT CHARGES	642	429	404	363
CUSTOMER SERVICE CHARGES	987	1,119	1,114	1,338
RETAIL TRANSACTION HUB/MKT PARTIPANT CHG	129	359	283	259
RETURN ON ASSETS CHARGE	-	-	562	265
MISCELLANEOUS REVENUE	645	290	234	420
TOTAL OTHER REVENUE	2,403	2,197	2,598	2,645

CUSTOMER SERVICE CHARGES

RENTAL INCOME	279	278	284	473
COLLECTION CHARGES	164	146	151	160
RECONNECTION CHARGES	22	27	13	25
SET UP CHARGES - RESIDENTIAL	399	554	495	494
NSF SERVICE CHARGES	56	52	36	30
TEMPORARY SERVICE INSTALLATION	58	56	54	70
LETTER OF REFERENCE	-	-	18	23
CREDIT CHECK	-	-	54	55
OTHER MISCELLANEOUS CHARGES	7	6	8	8
	987	1,119	1,114	1,338

REVENUE FROM SPECIFIC SERVICE CHARGES

Rate Code	Description	Standard Amount (Rate) \$	Applicable ?	Update d Amt. (if applic.) \$	Actual 2002 Volume	Actual 2003 Volume	Actual 2004 Volume	Actual 2005 Volume
1	Arrears certificate / Easement Letter	15.00	Y	15.00	402	360	441	355

2	Request for other billing information (including Letter of Reference)	15.00	Y	15.00	0	0	1,176	1,565
3	Income tax letter	15.00	Y	15.00	65	46	88	65
4	Credit reference/credit check (plus credit agency costs) - Residential	15.00	Y	15.00			3,515	3,488
5	Returned cheque charge (plus bank charges)	15.00	Y	12.50	4,496	4,141	2,906	2,403
6	Account set up charge/change of occupancy charge (plus credit agency costs if applicable) - General Service	30.00	Y	30.00	2,316	2,888	3,407	3,517
7	Special meter reads	30.00	Y	30.00				
8	Collection of account charge - no disconnection	30.00	Y	9.00	18,271	16,196	16,829	17,820
9	Disconnect/Reconnect at meter - during regular hours	65.00	Y	20.00	827	1,055	360	1,241
10	Disconnect/Reconnect at meter - after regular hours	185.00	Y	32.00	0	0	0	0
11	Disconnect/Reconnect at pole - during regular hours	185.00	Y	185.00	20	20	20	2
12	Disconnect/Reconnect at pole - after regular hours	415.00	Y	415.00	5	5	5	0
13	Meter dispute charge plus Measurement Canada fees (if meter found correct)	30.00	Y	10.00	18	12	14	19
14	Temporary service install & remove - overhead - no transformer	500.00	Y	400.00	144	141	136	174
15	Specific Charge for Access to the Power Poles \$/pole/year	22.35	Y		12,489	12,443	12,709	21,150
Additional Charges - Please be Specific								
16	Account set up charge/change of occupancy charge (plus credit agency costs if applicable) - Residential	N/A	Y	20.00	16,500	23,373	19,655	19,419
17	Interval Meter Request Change	N/A	Y	40.00	7	3	1	0
18	Credit reference/credit check (plus credit agency costs) - Gen. Service - See section 2.4.11 b of DSC	N/A	Y	25.00	0	0	39	96
19	Standby Charges - Britannia	N/A	Y	200.00	0	0	0	4

20	Standby Charges - GTAA	N/A	Y	500.00	0	0	0	1

Administration Charge Revenue 2002 - 2006

<u>Details by Class</u>	2002 <u>Actual</u>	2003 <u>Actual</u>	2004 <u>Actual</u>	2005 <u>Actual</u>	2006 <u>Actual</u>
<u>Class</u>	<u>Total</u>	<u>Total</u>	<u>Total</u>	<u>Total</u>	<u>Total</u>
Residential	213,875	376,191	424,724	410,764	412,735
Small Commercial	397	908	8,910	10,031	9,054
0-50	26,732	49,577	43,390	40,078	38,815
50-499	9,624	9,581	10,000	8,809	8,395
500-4999	1,009	1,010	1,011	1,005	1,044
Large User	19	28	26	24	27
Street Lighting	91,937	139,591	141,080	47,206	-
Grand Total	343,593	576,887	629,141	517,916	470,070

a.(ii) weather normalized data (where appropriate), and

Enersource budgets based on normalized costs of power, as detailed in the Short Term Load Forecast in Exhibit B/ Schedule 3/ Tab2. For comparison of Enersource's weather normalized methodology to actual results please see response to CCC #8 & #9.

b. Identify the data values that incorporate the effects of the Applicant's CDM programs.

See response to Board Staff question #20.

Interrogatory

#17 - Ref: Exhibit B/ Schedule 2/Tab 1/page 2/ Line 4

In Tab 1, page 2, in describing how the forecast of the Number of Customers was developed, the Applicant notes: “A specific adjustment has been made to the number of residential customers to take into account the number of new customers residing in condominium units....”

a. Please describe the specific adjustment that was made and illustrate this with the values used to make the adjustment.

Response

The specific adjustment made to the residential customer class relates to the recognition of new or incremental residential customers residing in condominiums that arise because of the provision of Individual Suite Metering. Extensive condominium development is occurring in Enersource's service territory and a number of retrofit projects are proposed at existing condominium buildings. These projections are consistent with Enersource's Smart Meter Implementation Plan that was filed with the Board on December 15, 2006.

The average residential customer additions for new & retrofit condos included in the 2008 rate year is as follows:

	Average # Customers
Customer additions for New Condo's	1,138
Customer additions for Retrofit Condo's	2,178

Interrogatory

#18 - Ref: Exhibit B/ Schedule 2/Tab 2/page 1; Ref: Exhibit B/ Schedule 3/Tab 2/page 5

In Schedule 2, Tab 2, page 1, the Applicant provides a table showing Energy Deliveries; a note on the table states: "2008 data includes Conservation and Demand Management." The table in Schedule 3, Tab 2, page 5, also shows energy delivery but the value for 2006 is different from that in the previously-referenced table. The extent to which CDM and weather normalization has been included in these tables is unclear. Without unnecessary duplication of the information already provided in the Applicant's responses to Board staff interrogatory No. 15 above, please explain:

- a. Whether the effects of CDM have been included in the table in Schedule 2, Tab 2, page 1, for 2006 and 2007,**
- b. If the CDM effects in (a) have not been included for 2006 and/or 2007, then what is the Applicant's estimate of the potential variance that may have been introduced by mixing data that includes CDM effect with data that does not,**
- c. Whether the effects of CDM have been included for the applicable years in the table in Schedule 3, Tab 2, page 5, and**
- d. To what extent the inclusion/exclusion of weather normalization accounts for the differences in the two tables.**

Response

- a. Yes. CDM has been included in this table for 2006 and 2007.**
- b. N/A**
- c. Yes, CDM is included as these are actual energy consumptions.**
- d. The difference between the two tables is related to energy losses. As you will note the table in Schedule 2/ Tab2/ page 1 notes the following, "Energy Deliveries Data in kWh (excluding Losses)".**

Interrogatory

#19 - Ref: Exhibit B/ Schedule 2/Tab 2/page 2

In Tab 2, page 2, the Applicant provides a table showing energy consumption per customer and, at the bottom of the table, provides a total of the preceding values for each column. This total does not take into account the relative number of customers in each class (i.e. it is un-weighted). Please provide the following:

- a. Clarify if any of these totals are used in the subsequent development of the forecast.**
- b. If the totals are used as in (a) above, carefully explain and show by example how the totals are used, and**
- c. Please explain how the data in the “3 Yr Avg.” column subsequently used in the development of the forecast.**

Response

- a. The totals are for informational purpose and are not used in the development of the forecast.
- b. N/A
- c. Again these totals are for informational purpose only and are not used in the development of the forecast.

Interrogatory

#20 - Ref: Exhibit B/ Schedule 2/Tab 2/page 2; Exhibit B/ Schedule 2/Tab 2.1

In Tab 2, page 2, the Applicant notes that the forecast for energy savings is provided in Exhibit B/Schedule 2/Tab 2.1. In Tab 2.1 a table of values is presented without explanation. Also, in the table in Tab 2.1, the same values are shown for various groups of months; i.e. the same values are shown for January to April, a different value is shown for May, values shown for June and July are the same, and the values for August to December are the same. Please explain the development of the 2008 CDM Savings forecast in Tab 2.1 and provide the historical values that the forecast is based on. Please explain in detail the reasons for the similarity of the many values in the body of the table.

Response

Enersource notes that the projected 2008 CDM forecast savings provided in Exhibit B/Schedule 2/Tab 2.1 represents incremental savings other than those achieved through past programs. Enersource's Conservation and Demand Management staff provided estimates of the energy savings anticipated to be observed in the service area in the 2008 Test Year. The values represented by month in the table reflect the allocation of the forecasted 2008 annual CDM savings.

Interrogatory

#21 - Ref: Exhibit B/ Schedule 2/Tab 2/page 2; Exhibit B/ Schedule 3/Tab 2/page 21 and 22

In Schedule 2, Tab 2, page 2, the Applicant provides a table of the annual energy consumption per customer for the years 2006, 2007 and 2008; a note on the table states: “2006 data represents actual weather”. However, in Schedule 3, Tab 2, pages 21 and 22, the Applicant presents a table displaying, from January 1997 to December 2004, both the energy and peak weather normalized values by month. Please clarify in detail, the following:

- a. If the energy consumption forecasts for 2007 and 2008 are based on actual (i.e. non-weather normalized data) or weather-corrected data or a combination of both,**
- b. If the forecasts are not based solely on weather normalized data, then what is the magnitude of the variance the Applicant estimates has been introduced into the forecast, and**
- c. Clarify the number of years of data (specifying, by year, if these are weather normalized or otherwise) used as a basis to forecast the future years; i.e. was only 2006 non-weather-corrected data used, or 2002 to 2006 non-weather-corrected data used, or 1997 to 2004 weather-corrected data used, etc?**

Response

a. In Exhibit B/ Schedule 2/Tab 2/page 2, the 2007 energy consumption forecast is based on 4 months of actual data and 8 months of estimated weather normalized data per the Short Term Load Forecast.

Please see attached spreadsheet that updates Appendix A of Exhibit B/Schedule 3/Tab 2 to include actual data from January 1, 1997 to April 30, 2007. The forecast beyond April 30, 2007 utilizes a normal weather scenario and forecasted econometric data from May 2007 to December 2009.

b. The Short Term Energy Forecast documented in Exhibit B/Schedule 3/Tab 2 was developed on normal weather scenario.

c. Please see response to question (a) above. Thirty-five (35) years of historical weather data commencing from January 1st 1970 was used to calculate the normal weather scenario, the process is described in Exhibit B/Schedule 3/Tab 1. Page 3 identifies the process used for weather correcting (weather normalization) of actual data.

Interrogatory

#22 - Ref: Exhibit B/ Schedule 2/Tab 2/page 1, 2; Exhibit B/ Schedule 3/Tab 1/page 3

In Schedule 2, Tab 2, pages 1 & 2, Enersource discusses its weather normalization process and notes: “The time period of the past actual data utilized in creating the model was 10 years starting from 1996.” In further discussion of the weather-normalization process in Schedule 3, Tab 1, page 3, Enersource notes that a second step in the process is: “Creating a Normal Weather Scenario based on 35 years of weather data”. Evidently, there are two time periods involved in the Applicant’s weather-normalization process.

a. Please explain in detail the respective roles played by the 35-year period data and the 10-year-period data in the weather normalization process.

Response

Patterns for weather normalization were developed based on 35 years of actual weather data attained from the Lester B. Pearson International Airport weather station. The process to deriving the ‘normal weather year’ scenario is described in Exhibit B/Schedule 3/Tab 1/ Page 1. The Short Term Load Forecasting model was developed using 10 years of actual system load, with the weather normalization applied.

Interrogatory

#23 - Ref: Exhibit B/Schedule 2/Tab 5a

a. Please provide a breakdown of 2006 Board Approved Other Revenue and an explanation of the changes.

Response

The Board approves the customer service charges associated with other revenue.

Please see table below which includes 2006 Board Approved Other Revenue. In the 2006 Board approved customer service charges the Board used a three year average of 2002 – 2004 (based on units). Similarly, in the 2008 Rate Application Enersource has relied on a forecast based on past trend to determine Customer service charges. With regards to late payment charges Enersource has forecasted the 2008 amounts based on the expected level of customers that fail to pay their bills on time. To derive 2008 retail transaction / market participant revenue, Enersource forecasted the number of retailers and the anticipated customers signed with retailers.

OTHER REVENUE

(000's)

	2006 EDR
LATE PAYMENT CHARGES	404
CUSTOMER SERVICE CHARGES	1,123
RETAIL TRANSACTION HUB/MKT PARTICIPANT CHG	283
MISCELLANEOUS REVENUE	276
TOTAL OTHER REVENUE	2,086
<u>CUSTOMER SERVICE CHARGES</u>	
RENTAL INCOME	280
COLLECTION CHARGES	154
RECONNECTION CHARGES	21
SET UP CHARGES - RESIDENTIAL	483
NSF SERVICE CHARGES	48
TEMPORARY SERVICE INSTALLATION	56
LETTER OF REFERENCE	18
CREDIT CHECK	53
OTHER MISCELLANEOUS CHARGES	10
	1,123

Interrogatory

#24 - Ref: Exhibit A/ Schedule 14/ Tab 1

Please state whether or not Enersource incurs any distribution expenses through the purchase of services or products. If Enersource does incur such expenses, please provide:

- (i) the identity of each company transacting with the applicant,**
- (ii) a summary of the nature of the activity transacted,**
- (iii) the annual dollar value in aggregate of transactions and**
- (iv) a description of the specific methodology used in determining the price (e.g. summary of tendering process/summary of cost approach).**

Response

- (i) Enersource incurs distribution expenses from Enersource Corporation by way of management fee allocation.
- (ii) Enersource Corporation provides a number of corporate services to Enersource including:
 - a. Corporate Governance/Legal Services;
 - b. Communications and Public Relations;
 - c. Emergency and Safety Services;
 - d. Finance Services;
 - e. Human Resources Services;
 - f. Purchasing;
 - g. Other (including Administrative Support Services; and Internal Audit and Risk Management).

The description of each service can found at Exhibit A/Schedule 14/Tab 4.

- (iii) The annual dollar value in aggregate of the above expense allocations are as follows:

2006 Actual	2007 Bridge	2008 Test
\$7,802	\$8,384	\$8,243

Enersource incurs expenses that are eligible for recovery through rates through the purchase of services from affiliates. In general, Enersource incurs such expenses from a variety of providers of goods and services.

- (iv) Please see the response to Board staff interrogatory 25 (ii), (iii) and (iv).

Interrogatory

#25 - Ref: Exhibit D/ Schedule 1/ Tab 11

On Page 1 of 6, Enersource states that it “forecasts a management fee of \$8.243 million in the 2008 Test Year and seeks to recover this amount through rates.” This is related to the provision of corporate functions by Enersource Corporation to Enersource. Please provide for all shared services:

- (i) a description of the type of service (e.g. IT, office space, etc.),**
- (ii) total annual expense by service,**
- (iii) rationale and the cost allocators used for shared costs, for each type of service (e.g. square footage, computers, headcount, etc.) and**
- (iv) a detailed description of the assumptions underlying the allocation of corporate costs, including documentation of Enersource’s overall methodology and policy in this area.w**

Response

- (i) The description of each service can found under Exhibit A/Schedule 14/Tab 4.
- (ii) Please see chart below:

	Cost Driver	Amount	Allocation %	Enersource Hydro
Corporate Governance	Time Estimate	\$ 210	90%	\$ 189
Executive Management/Communications and Public Relations	Time Estimate	2,235	90%	2,012
Safety	Time Estimate	727	90%	654
Human Resources	Headcount	1,095	92%	1,008
Finance	Time Estimate	3,814	80%	3,051
Purchasing	Time Estimate	153	90%	138
Legal	Time Estimate	320	30%	96
Enersource Hydro Charges	Historical	842	85%	715
Capital Tax	Historical	20	85%	17
Other Expense/Financial Income	Historical	431	85%	364
Total Cost		<u>\$ 9,846</u>		<u>\$ 8,243</u>

- (iii) The cost drivers for each service were developed either by headcount, time/benefit estimates or historical information appropriate to the cost being allocated. Please refer to Exhibit D/Schedule 1/Tab 11/page 2 of 6.
- (iv) Enersource’s overall methodology is to charge each affiliate an appropriate share of corporate overhead costs. Enersource Corporation allocates actual costs to each affiliate based on the budgeted allocation percentage.

Interrogatory

#26 - Ref: Exhibit D/ Schedule 2/ Tab 5 and Exhibit D/ Schedule 2/ Tab 6

These tables provide OM&A variance analysis for 2008 vs. 2007 and 2007 vs. 2006 respectively. Please provide a similar variance analysis for Historical Board Approved data for 2006 vs. Historical Actual data for 2006.

Response

Note: all amounts in \$000's.

	Historical Year	EDR		Variance
	2006	2006	Variance \$	%
<u>OM&A Variance Analysis 2007 vs 2006</u>	29,174	27,622	1,552	16.0%

Variance Breakdown

Total Manpower	\$1,430	5.2%
Total Material	\$486	1.8%
Total Transportation	(\$15)	-0.1%
Total Other	(\$349)	-1.3%
Total	\$1,552	5.6%

The increase in total manpower costs is attributed to the following:

5 New Positions @ \$65k Average Salary	\$325	1.2%
3 % Increase in average compensation - for 2 years	\$1,105	4.0%
Total Manpower	\$1,430	5.2%

The increase in total material costs is attributed to the following:

Project Material and Consumables	\$486	1.8%

The increase in total transportation costs is attributed to the following:

Fuel	-\$15	-0.1%

The increase in total other costs is attributed to the following:

4 Months Deferral of OEB costs	(\$214)	-0.8%
Other inflation/other year over year variances/Timing of 2nd Generation CDM	(\$135)	-0.5%
Total Other	(\$349)	-1.3%
	\$1,552	5.6%

Interrogatory

#27 - Ref: Exhibit D/ Schedule 2/ Tab 1

Please provide a breakdown of total Full Time Employees (FTE); total Part-Time Employees, Total Salaries & Wages and Benefits, and Salaries and Wages and Benefits charged to O&M by employee type (i.e. management, analyst, non-unionized and unionized). Please include total compensation by group and average level per group as well as details on any incentive programs including how employee performance is measured and how the incentive level is determined. Please provide the requested information for 2006 Board approved, 2006 historical, 2007 bridge and 2008 test years.

Response

[Please see the table below.](#)

	2006 EDR	2006 ACTUAL	2007 BRIDGED	2008 TEST
BY CATEGORY:				
NON UNION	3,244	3,417	3,744	4,162
ANALYST	1,306	1,540	1,687	1,876
MANAGEMENT	1,641	2,012	2,205	2,451
OUTSIDE	5,543	5,429	6,495	6,849
INSIDE	3,582	3,773	4,390	4,880
TEMPORARY	286	332	339	270
Adjustment (Manpower Re-class)				325
TOTAL SALARIES & WAGES - REGULAR	15,602	16,503	18,860	20,812
NON UNION - OVERTIME	123	160	72	110
ANALYST-OVERTIME	55	72	74	31
MANAGEMENT-OVERTIME	72	94	0	0
OUTSIDE - OVERTIME	675	913	726	739
INSIDE - OVERTIME	11	25	30	33
TOTAL OVERTIME	936	1,263	902	913
TOTAL SALARIES, WAGES & OVERTIME	16,538	17,766	19,762	21,726
CONTRACT LABOUR	2,544	2,647	2,994	3,029
TRAINING / SAFETY	99	149	599	549
OTHER *	73	121	151	206
TOTAL OTHER MANPOWER	2,716	2,918	3,743	3,784
TOTAL MANPOWER	19,254	20,684	23,505	25,510
*Employee Relations, Uniforms, Hiring, Disability Management, etc.				
ENERSOURCE HYDRO MISSISSAUGA HEADCOUNT	2006 EDR	2006 ACTUAL	2007 BRIDGED	2008 TEST
BY CATEGORY:				
NON UNION	59	60	59	63
ANALYST	23	26	26	28
MANAGEMENT	23	29	29	31
OUTSIDE	119	114	123	124
INSIDE	63	64	67	72
TEMPORARY	6	7	6	5
TOTAL HEADCOUNT	293	300	310	323
AVERAGE \$ BY CATEGORY:				
NON UNION	\$55	\$57	\$63	\$66
ANALYST	\$57	\$59	\$65	\$67
MANAGEMENT	\$71	\$69	\$76	\$79
OUTSIDE	\$47	\$48	\$53	\$55
INSIDE	\$57	\$59	\$66	\$68
TEMPORARY	\$48	\$47	\$57	\$54

Information on incentive program

1) Description

The incentive compensation plan for Enersource Hydro Mississauga is based on the following performance measures:

- Reliability
- Safety
- Performance Based Regulation
- Enersource Net Income

2) Performance Measures

List of specific performance measures:

RELIABILITY: Annual Average Outage per Customer

- SAIDI [System Average Interruption Duration Index] [in minutes]
- SAIFI [System Average Interruption Frequency Index] [in quantity]

SAFETY:

Number of Preventable Lost Time Injuries

PERFORMANCE BASED REGULATION: Service Quality PBR Indicators

Customer Service

- Incoming calls answered by Customer Service Representative within 30 seconds

Connection of New Services

- <750 volts connected within 5 working days from the day on which all conditions of service are satisfied
- >750 volts connected within 10 working days from the day on which all conditions of service are satisfied

Underground Cable Locates

- Completion within 5 working days of a customer's request

Appointments

- Appointments at customer's premises met within appointed time

Written Response to Inquiries

- Written response to inquiries from customer or agent of customer, within 9 working days following receipt of request

Emergency Response

- Emergency trouble calls response within 60 minutes.

ENERSOURCE NET INCOME BEFORE TAXES

Identification of Stakeholder Who Benefits:

- Reliability – Rate Payer
- Safety – Rate Payer/Employees
- Performance Based Regulation – Rate Payer
- Enersource Net Income – Shareholder – Self Funding (Not included in 2008 rate application expenses)

Interrogatory

#28 - Ref: Exhibit D/ Schedule 1

Please provide the status of Enersource's pension fund and all assumptions used in the analysis, including summary data on the age distribution of the workforce and a forecast of retirements by employee category from 2007 to 2010.

Response

The Enersource pension fund is OMERS. Please see the 2 actuarial studies attached.

Enersource is not able to provide the requested information on the number of employees forecast to retire from 2007 – 2010. There is no longer a legal requirement that an employee retire at a specific age or under specific circumstances or conditions. Enersource has a number of employees who, although eligible to retire on a full pension and have chosen to continue working.

Interrogatory

#29 - Ref: Exhibit D/ Schedule 2/ Tab 1

Please prepare a detailed reconciliation of Enersource's 2006 Audited Financial Statements to the 2006 Historical Actual data reported in Exhibit D Schedule 2 Tab 1. In particular please include an explanation for the credit of \$438,000 with the description "Non-Distribution Expense/Revenue Reclass".

Response

The \$438,000 is related to GTAA Interconnect is excluded from expense as this is not related to Enersource distribution operations.

Interrogatory

#30 - Ref: Exhibit D/ Schedule 2/ Tab 1

Please provide a detailed variance analysis for Enersource's 2006 EDR OEB approved OM&A expenses below to Enersource's 2006 Actual OM&A Expenses as reported on Exhibit D Schedule 2 Tab 1.

Response

As noted in Exhibit A / Schedule 12 / Tab 6 and 7, Enersource's variance analysis of its Operating, Maintenance and Administration expense is formatted consistent with the presentation of Enersource's financial statements.

Operating Expenses:	2006 EDR	2006 Actual	Variance
Controllable Costs:			
Manpower	19,254	20,684	1,430
Materials	1,376	1,862	486
Transportation	983	968	(15)
Other	5,599	5,660	61
Subtotal Controllable Costs	27,212	29,174	1,962
Capital Taxes	1,469	1,557	88
CDM operating expenses	1,525	1,906	381
Other Expenses	3,047	2,557	(490)
Bad Debt	958	2,580	1,622
Recoveries/Management Fees	452	(338)	(790)
Total - Operations, maintenance and administration	34,663	37,436	2,773
Less: Non-Distribution Expenses/Revenue Reclass	(561)	(438)	123
Subtotal	34,102	36,998	2,896

Amortization of capital assets

Additional overhead capitalized from increased certain capital expenditures
Additional expense due to increased capital expenditures

	29,966	30,275	309	
Amortization of regulatory assets	7,285	7,144	(141)	
Total Distribution Expenses	71,353	74,417	3,064	
Amortization of regulatory assets	(7,285)	(7,144)	141	
Capital Taxes	(1,469)	(1,557)	(88)	
Low Voltage	(590)	-	590	Low Voltage is COP
Total Adjustments	(9,344)	(8,701)	643	
Board #30 - OEB 2006 EDR Approved Distribution Expenses	62,009	65,716	3,707	

Interrogatory

#31 - Ref: Exhibit D/ Schedule 1/ Tabs 2 to 6 inclusive, and 11 and Exhibit D/, Schedule 2/, Tab 1

For each of Enersource's "Cost of Service" detail by work unit, please provide budget amounts for the 2006 Actual, 2007 Bridge and 2008 Test years (reference Exhibit D, Schedule 2, Tab 5 for example of structure). With each budget please provide a variance analysis for changes and summary details with incremental values to account for changes.

Each work unit summary should isolate and address issues such as the following:

- Current labour changes/adjustments**
- Staffing changes due to economic changes (i.e. customer growth, call growth)**
- Staffing changes due to changes other than economic changes (i.e. new project)**
- Change in external labour usage (outsourcing, consulting, contracting etc.)**
- Current contractual changes other than labour**
- New contractual changes other than labour**
- One time charges expected, reversed or maintained as contingency**

Response

Schedule of 2006-2008 Total Controllable
Cost

Name	2006 Actual	2007 Forecast	2008 Budget	2006-2007 Variance	2007-2008 Variance
CONTROL SYSTEM	1,707	1,672	1,837	- 35	165
CORPORATE RECORDS	585	792	908	207	116
GROUND & BUILDINGS	1,539	1,785	1,946	246	161
SUBSTATION OPERATIONS	1,388	1,965	2,044	577	79
SYSTEM PLANNING	205	292	372	87	80
TROUBLE TRUCK	102	107	106	5	- 1
CABLE LOCATES	570	639	656	69	17
U/G MAINT, REPAIRS & BURNOFFS	2,073	2,215	2,275	142	60
O/H MAINTENANCE & REPAIRS	1,645	1,976	1,997	331	21
TREE TRIMMING	694	765	770	71	5
GARAGE	1,523	1,612	1,694	89	82
OVERHEAD CONSTRUCTION	685	764	805	79	41
IND/COM'L CUST PROJ/INSPECTIONS	884	775	799	- 109	24
STORES	843	975	1,128	132	153
Operations	14,443	16,334	17,337	1,891	1,003
CUSTOMER SERVICES ADMIN	1,613	1,705	1,864	92	159
SETTLEMENTS	624	903	928	279	25
CUSTOMER ACCOUNTS	3,789	4,611	4,769	822	158
CUSTOMER BILLINGS	523	493	517	- 30	24
METERING	707	885	980	178	95
Customer Service	7,256	8,597	9,058	1,341	461
Admin	3,580	4,216	4,539	636	323
IT Support	3,896	4,682	5,275	786	593
Total OM&A	29,175	33,829	36,209	4,654	2,380

Schedule of 2006-2008
Manpower Controllable Cost

Name	2006 Actual	2007 Forecast	2008 Budget	2006-2007 Variance	2007-2008 Variance
CONTROL SYSTEM	1,307	1,222	1,375	- 85	153
CORPORATE RECORDS	540	722	839	182	117
GROUND & BUILDINGS	178	223	224	45	1
SUBSTATION OPERATIONS	572	1,019	1,067	447	48
SYSTEM PLANNING	200	287	366	87	79
TROUBLE TRUCK	64	78	77	14	- 1
CABLE LOCATES	530	595	613	65	18
U/G MAINT, REPAIRS & BURNOFFS	1,649	1,760	1,812	111	52
O/H MAINTENANCE & REPAIRS	1,063	1,268	1,289	205	21
TREE TRIMMING	511	558	563	47	5
GARAGE	576	556	596	- 20	40
OVERHEAD CONSTRUCTION	478	551	579	73	28
IND/COM'L CUST PROJ/INSPECTIONS	774	683	703	- 91	20
STORES	395	412	498	17	86
Operations	8,837	9,934	10,601	1,097	667
CUSTOMER SERVICES ADMIN	1,565	1,655	1,814	90	158
SETTLEMENTS	586	662	687	75	25
CUSTOMER ACCOUNTS	2,911	3,470	3,593	559	122
CUSTOMER BILLINGS	522	493	517	- 29	24
METERING	548	700	795	152	96
Customer Service	6,133	6,981	7,406	848	425
Admin	3,260	3,899	4,097	639	198
IT Support	2,454	2,691	3,081	237	390
Manpower re-class adjustment			325		325
Total OM&A	20,684	23,505	25,510	2,821	2,005

Schedule of 2006-2007
Manpower Controllable Cost

Name	2006- 2007 Variance	Salary Increases	Standby	Safety Training	Substation Maintenance	Other/Pension
CONTROL SYSTEM	85	39				
CORPORATE RECORDS	182	16				
GROUND & BUILDINGS	45	5				
SUBSTATION OPERATIONS	447	79	80		160	
SYSTEM PLANNING	87	6				
TROUBLE TRUCK	14	2				
CABLE LOCATES	65	16				
U/G MAINT, REPAIRS & BURNOFFS	111	49				
O/H MAINTENANCE & REPAIRS	205	82				
TREE TRIMMING	47	15				
GARAGE	-					
OVERHEAD	20	17				
CONSTRUCTION	73	14				
IND/COM'L CUST	-					
PROJ/INSPECTIONS	91	23				
STORES	17	12				
Operations	1,097	377	80	-	160	-
CUSTOMER SERVICES ADMIN	90	47				
SETTLEMENTS	75	18				
CUSTOMER ACCOUNTS	559	134				
CUSTOMER BILLINGS	29	16				
METERING	152	56				
Customer Service	848	271	-	-	-	-
Admin	639	163		175		
IT Support	237	98				
Pension/Benefits/New Positions (see note)	-					1,498
Rounding						1
Total OM&A	2,821	909	80	175	160	1,497

Note:

Pension and benefits increases of \$718 are based on the number of employees in each business unit/work unit. The proportionate amount for each unit is based on type and number of employees in each area. An average was used for each new hire. The total incremental OM&A costs forecasted due to the new positions from 2006-2007 is \$780. Please see attached headcount reconciliation.

Schedule of 2007-2008 Manpower Controllable Cost

Name	2007- 2008 Variance	Salary Increases	Usual Vacant Rate
CONTROL SYSTEM	153	63	12
CORPORATE RECORDS	117	42	7
GROUND & BUILDINGS	1	7	2
SUBSTATION OPERATIONS	48	39	9
SYSTEM PLANNING	79	22	3
TROUBLE TRUCK	1	2	1
CABLE LOCATES	18	21	5
U/G MAINT, REPAIRS & BURNOFFS	52	62	16
O/H MAINTENANCE & REPAIRS	21	42	11
TREE TRIMMING	5	18	5
GARAGE	40	24	5
OVERHEAD CONSTRUCTION	28	21	5
IND/COM'L CUST PROJ/INSPECTIONS	20	24	6
STORES	86	27	4
Operations	667	414	92
	-		-
CUSTOMER SERVICES ADMIN	158	87	16
SETTLEMENTS	25	24	6
CUSTOMER ACCOUNTS	122	115	31
CUSTOMER BILLINGS	24	19	4
METERING	96	38	7
Customer Service	425	283	64
	-		-
Admin	198	151	36

	-		-
IT Support	390	204	27
Manpower reclass adjustment Rounding	325		
Total OM&A	2,005	1,053	218

An average was used for each new hire. The total incremental OM&A costs forecasted due to the new positions from 2007-2008 is \$1,170. Please see attached headcount reconciliation. The usual vacant rate is based on an average of 20 positions vacant for the total Enersource family of companies for an average of 10 weeks multiplied by an average salary of \$65.

Schedule of 2006-2008 Transportation Controllable Cost

Name	2006 Actual	2007 Forecast	2008 Budget	2006- 2007 Variance	2007- 2008 Variance
CONTROL SYSTEM	15	17	17	2	-
CORPORATE RECORDS	-	1	1	1	-
GROUND & BUILDINGS	7	17	18	10	1
SUBSTATION OPERATIONS	110	160	165	50	5
SYSTEM PLANNING	1	1	1	-	-
TROUBLE TRUCK	-	-	-	-	-
CABLE LOCATES	33	35	35	2	-
U/G MAINT, REPAIRS & BURNOFFS	228	255	255	27	-
O/H MAINTENANCE & REPAIRS	223	220	220	3	-
TREE TRIMMING	137	139	139	2	-
GARAGE	27	58	62	31	4
OVERHEAD CONSTRUCTION	16	16	16	-	-
IND/COM'L CUST PROJ/INSPECTIONS	26	31	31	5	-
STORES	27	27	27	-	-
Operations	850	977	987	127	10
CUSTOMER SERVICES ADMIN	8	10	10	2	-
SETTLEMENTS	4	4	4	0	-
CUSTOMER ACCOUNTS	10	12	12	1	1
CUSTOMER BILLINGS	0	-	-	0	-

METERING	56	66	66	10	-
Customer Service	79	92	93	13	1
Admin	36	37	40	1	3
IT Support	3	1	1	2	-
Total OM&A	968	1,108	1,121	140	13

Transportation costs have increased year over year mainly due fuel price increases.

Schedule of 2006-2008 Material Controllable Cost

Name	2006 Actual	2007 Forecast	2008 Budget	2006- 2007 Variance	2007- 2008 Variance
CONTROL SYSTEM	5	6	6	1	-
CORPORATE RECORDS	-	-	-	-	-
GROUND & BUILDINGS	25	32	33	7	1
SUBSTATION OPERATIONS	58	66	69	8	3
SYSTEM PLANNING	4	2	2	2	-
TROUBLE TRUCK	38	29	29	9	-
CABLE LOCATES	4	4	4	-	-
U/G MAINT, REPAIRS & BURNOFFS	196	200	208	4	8
O/H MAINTENANCE & REPAIRS	332	313	313	19	-
TREE TRIMMING	45	68	68	23	-
GARAGE	670	717	745	47	28
OVERHEAD CONSTRUCTION	86	90	98	4	8
IND/COM'L CUST PROJ/INSPECTIONS	53	34	34	19	-
STORES	242	303	329	61	26
Operations	1,758	1,864	1,938	106	74
CUSTOMER SERVICES ADMIN	6	1	1	5	-
SETTLEMENTS	-	-	-	-	-
CUSTOMER ACCOUNTS				-	

	3	3	3	0	-
CUSTOMER BILLINGS	-	-	-	-	-
METERING	29	23	23	6	-
Customer Service	38	27	27	11	-
				-	
Admin	58	40	40	17	-
				-	
IT Support	8	0	0	8	-
Total OM&A	1,862	1,932	2,006	70	74

Project material and Consumable cost increases due mainly to inflation.

Schedule of 2006-2008 Other Controllable Cost

Name	2006 Actual	2007 Forecast	2008 Budget	2006- 2007 Variance	2007- 2008 Variance
CONTROL SYSTEM	380	427	439	47	12
CORPORATE RECORDS	45	70	69	25	1
GROUND & BUILDINGS	1,329	1,513	1,672	184	159
SUBSTATION OPERATIONS	647	721	743	74	22
SYSTEM PLANNING	-	2	2	2	-
TROUBLE TRUCK	-	-	-	-	-
CABLE LOCATES	4	4	4	-	-
U/G MAINT, REPAIRS & BURNOFFS	1	1	1	-	-
O/H MAINTENANCE & REPAIRS	26	175	175	149	-
TREE TRIMMING	1	-	-	1	-
GARAGE	251	281	290	30	9
OVERHEAD CONSTRUCTION	104	107	112	3	5
IND/COM'L CUST PROJ/INSPECTIONS	31	28	32	3	4
STORES	176	231	272	55	41
Operations	2,995	3,560	3,811	565	251

CUSTOMER SERVICES ADMIN	34	39	39	5	0
SETTLEMENTS	34	237	237	203	-
CUSTOMER ACCOUNTS	864	1,125	1,161	261	36
CUSTOMER BILLINGS	-	-	-	-	-
METERING	75	95	95	20	-
Customer Service	1,006	1,496	1,532	490	36
Admin	226	240	362	14	122
IT Support	1,433	1,988	2,192	555	203
			-	-	-
			325		325
Total OM&A	5,660	7,284	7,572	1,624	288

Notes

2006-2007

Garage –increases Vehicle Maintenance costs of \$137.

Admin and IT – communication costs increases of \$14 and \$171.

Substation operations - equipment repair costs of \$74

O/H Maintenance & Repairs - equipment repair costs of \$74

Grounds and Building – Property Tax and Building Maintenance cost increases of \$87 and Heat/Hydro of \$69

Customer Accounts – Postage and Bill Delivery increases of \$261

The remaining variance 2006-2007 of \$252 can be attributed to general economic increases or inflation. The IT software maintenance/licences increases are mainly due to increased IT integration, infrastructure investments and number of employees.

Notes

2007-2008

Grounds and Building – Increases caused by Waste \$41, Property Tax and Building Maintenance cost increases of \$33 and Heat/Hydro of \$83

IT software maintenance/licences – increases of \$170

The remaining 2007-2008 variance of (\$38) can be attributed to a reduction in some electrical repairs year over year.

Staffing Changes and reason

Rates	Position Name	2005-2007	2007-2008	2008	Reason for position
No	Billing Analyst Customer Service Admin	1			This position assumes the responsibility of reporting and analysis requirements for Enersource Hydro Customer Care and Billing Operations Division.

No	Billing Supervisor	Customer Service Admin		1	A new Billing Supervisor position has been authorized to help the Manager, Billing Operations deal with:• the increased administrative complexity expected as a result of Smart Metering, billing at Time of Use rates, Standard Offer Program;
No	Customer Service Supervisor	Customer Service Admin		1	Increased demands and aging workforce.
No	Billing Quality Analyst	Settlements		1	This person is responsible for insuring and validating metering and settlement system configurations, meter data and meter billing for MIST (Metered Inside Settlement Timeframe) customers. Responsibilities include auditing, validating and reporting results
No	Office Services Clerk	Customer Accounts	1		Responsibilities: • Assign postage to all outgoing corporate mail and deliver the mail daily to the Post Office • Co-ordinate the equipment maintenance requirements and operate the Mail Inserter & Postage Machines for corporate outgoing mail and bills.
No	System Admin	Customer Accounts		1	The administrative duties related to Kubra services will grow to encompass user security, reporting, payment tracking and an e-bill bill inserts marketing segment with the upgrade early 2008. SharePoint will be our new document management software which will require an administrator.
No	Meter Technician Apprentice	Metering	1		Required to meet the quality assurance targets for Enersource.
No	Apprentice	Metering		1	The new apprentice is required to meet the mandates of the OEB for our Smart Meter initiative, which would include the installation of network communication collector meters; smart meters for C/I customers and our IMS projects.
No	Middleware Tech	Information systems		1	Managing the new "middleware" framework that will be implemented later this year.
No	New Network Specialist	Information systems		1	Additional position required due to increased demands and system complexity.
No	New Data Base Analyst	Information systems		1	Database Administrator for managing the new CC&B system.
No	New - IOM programmer	Information systems		1	The IOM System will be installed in 2008 and will require a Senior Programmer/Analyst for its support and maintenance. This is a new system, so we do not currently have anyone in this position.
No	Operating Model Engineer	Information systems	1		Ensure the availability and integrity of the operating model, complex data set compile from our AM.FM/GIS and scada systems and utilized by the system control operator to operate the distribution system.

No	New Standards Clerk	Admin	1	ESA Regulation 22/04 has come into effect and significantly increased the due diligence requirements for Enersource. The bulk of the compliance work is in the standards group. It also presented an opportunity to sell Standards and now upgrades to other LDCs.
No	Design Tech	System Planning	1	The Design Tech position is new to allow for the training of a new person to fill an upcoming retirement. Training of this nature is highly specialized and takes several years. The position is also required as a result of increased capital expenditures.
No	Grid planner/analyst	Corporate Records	1	The Grid Planner position was proposed as a new position that would perform the short term planning of the switching activities on the power grid. Typically, a system operator would be viewed as going into this position, however, with retirement and new a
No	Apprentice	Control System	1	New apprentices required to move from an 8 person rotation to a nine person rotation. The second position is to prepare an apprentice for the upcoming planned retirement of existing staff.
No	Apprentice	Control System	1	New apprentices required to move from an 8 person rotation to a nine person rotation. The second position is to prepare an apprentice for the upcoming planned retirement of existing staff.
No	Mapping engineer	Corporate Records	1	The Systems & Mapping Engineer is a new position necessitated by the implementation of the IOM System, and support the GIS middleware software and manages aspects of import/export workflow.
No	Apprentice	Substation Operations	1	The Apprenticeship Program is intended to provide additional line staff resources to replace employees that have been lost through attrition.
No	Apprentice	Substation Operations	1	The Apprenticeship Program is intended to provide additional line staff resources to replace employees that have been lost through attrition.
No	Materials Planner	System Planning	1	This position is responsible for preparing, maintaining, and coordinating construction schedules for capital, subdivision, industrial/ commercial and some maintenance service orders in a multiple project environment in the E&O division of Enersource.
No	Weekend Shift TTK	U/G Maint. & Repairs	1	This is an additional night permanent night shift crew to allow full 7 day a week 24 hour trouble truck coverage, which will improve response time to outage on weekend nights and help maintain our system reliability.
No	Weekend Shift TTK	O/H Maint. & Repairs	1	This is an additional night permanent night shift crew to allow full 7 day a week 24 hour trouble truck coverage, which will improve response time to outage on weekend nights and help maintain our system reliability. It will also ensure that we are able
No	Apprentice	U/G Maint. & Repairs	1	The Apprenticeship Program is intended to provide additional staff resources to replace employees that have been lost through attrition.
No	Apprentice	Tree Trimming	1	The Apprenticeship Program is intended to provide additional staff resources to replace employees that have been lost through attrition.

No	Apprentice	Tree Trimming	1		The Apprenticeship Program is intended to provide additional line staff resources to replace employees that have been lost through attrition.
No	Clerk	Industry/Commercial inspections	1		This position was budgeted to meet increasing requirements to process time charges from numerous Dept's.
No	Storekeeper	Stores	1		New projects. Also tool recording safety history, with regards to maintenance and repair. Safety reporting, monitoring gloves and safety wear.
No	ESA Compliance	Stores		1	Dealing with Ministry of Environment with regards to transformer history monitoring.
			12	5	13

Interrogatory

#32 - Ref: Exhibit D/ Schedule 1/ Tabs 2 to 6 inclusive, and 11 and Exhibit D/ Schedule 2/ Tab 1

Please provide details with amounts included in the individual work units for all smart meter related expenditures (reference Exhibit D, Schedule 1, Tab 1 Schedule I page 2 for example). Please provide any necessary distinction as to if the amount identified and budgeted is related to the minimum system requirement reporting as determined in the 2006 Combined Smart Meter decision or is incidental to these charges.

Response

All smart meter related costs are included in the smart meter rate adder. There are no costs in the individual work units. Enersource smart meter systems do not exceed the minimum functional requirements.

Interrogatory

33. Ref: Exhibit D/ Schedule 1/ Tab 11/ Page 1 With reference to the discussion on Management Fees/Recoveries, please provide a detailed explanation for the source of \$7.485 million in recoveries which offsets the \$8.243 million in management fees.

Response

The referenced amounts are independent of each other and were added for presentation purposes.

A description and breakdown of the management fees / recoveries can be found in Exhibit D / Schedule 1 / Tab 11.

Interrogatory

#34 - Ref: Exhibit D/ Schedule 2/ Tab 1

With reference to Management Fees/Recoveries shown in this table, please provide the amount included and reported as Management Fees and the related recoveries for each year. Also identify the amount of Management Fees that would have been included in the OEB approved 2006 EDR OM&A Expenses and the related recoveries. Using variance analysis please provide a summary with amounts detailing the incremental changes for each year.

Response

Description	2006 EDR	2006	2007	2008
Recoveries	- 7,042	- 8,140	- 8,174	- 7,485
Management Fees	7,494	7,802	8,384	8,243
Total	452	- 338	210	758

The year over year change in management fee allocations, are primarily due to economic increases. Recoveries or overhead allocations fluctuations are caused by the level of capital or recoverable work performed by Enersource in each year. In 2008, the recovery of overhead relating to smart meters has been included as part of the rate rider request.

Interrogatory

#35 - Ref: Exhibit D/ Schedule 2/ Tab 1

With reference to the line item Amortization of Regulatory Assets shown on this table, please explain why this amount is to be included in Enersource's distribution expenses.

Response

The amortization of regulatory assets is shown on this table to represent how Enersource's expense will be shown on its financial statements only. It is shown as a distribution expense to reflect how Enersource will record the recovery/reduction caused by rate riders.

Interrogatory

#36 - Ref: Exhibit D/ Schedule 2/ Tab 2

Please provide a copy of the minutes supporting Enersources Board of Directors final approval of the 2007 OM&A budget. Please reconcile the 2007 OM&A budget to the 2007 Forecast year values as presented on Exhibit D/ Schedule 2/ Tab 2. If the values reconciled are materially different please discuss what actions Enersource have taken to notify the Board of Directors of the differences, providing any Board of Directors minutes discussing the differences.

Response

The Board Minutes approving the 2007 OM&A budget

The table below provides a comparison of the 2007 forecasted expenditures to the 2007 budgeted expenditures:

Name	2007 Forecast	2007 Budget	Variance
CONTROL SYSTEM	1,672	1,654	18
CORPORATE RECORDS	792	858	(66)
GROUPS & BUILDINGS	1,785	1,572	213
SUBSTATION OPERATIONS	1,965	1,762	203
SYSTEM PLANNING	292	268	24
TROUBLE TRUCK	107	33	74
CABLE LOCATES	639	622	17
U/G MAINT, REPAIRS & BURNOFFS	2,215	1,988	227
O/H MAINTENANCE & REPAIRS	1,976	1,751	225
TREE TRIMMING	765	737	28
GARAGE	1,612	1,624	(12)
OVERHEAD CONSTRUCTION	764	700	64
IND/COM'L CUST PROJ/INSPECTIONS	775	706	69
STORES	975	943	32
Operations	16,334	15,217	1,117
CUSTOMER SERVICES ADMIN	1,705	1,672	33
SETTLEMENTS	903	917	(14)
CUSTOMER ACCOUNTS	4,611	4,564	47
CUSTOMER BILLINGS	493	500	(7)
METERING	885	843	42
Customer Service	8,597	8,496	101
Admin	4,216	4,289	(73)
IT Support	4,682	4,437	245
Total Business Units OM&A	33,829	32,439	1,390

Enersource's Board of Directors receive financial statements as compared to budget on a quarterly basis.

Interrogatory

#37 - Ref: Exhibit D/ Schedule 1/ Tab 1

In Enersource's 2006 EDR Application Model, Sheet "7-2 ALLOCATION - LV-Wheeling", Cell L120 has included an amount of approximately \$590,000 for Low Voltage charges. This Low Voltage charge was handled as a pass through charge in the 2006 EDR model. It was included into rates as a rate adder on the above referenced worksheet and accounted for as General and Administrative expense (or more intentionally as a revenue offset). Please confirm if Enersource has included a budget amount in the 2008 Cost of Service or OM&A budget for low voltage. If yes, then please state reasons for including and identify the amounts included, including detailed calculations. If no, please provide a confirmation that no amounts have been included in Cost of Service or OM&A for Low Voltage.

Response

Enersource has not included any amounts pertaining to Low Voltage in Cost of Service or OM&A in the 2008 Rate Application. Enersource has applied for Low Voltage charges as identified in the 2008 Rate application as a rate rider per Exhibit H/ Schedule 2/ Tab 3.

Interrogatory

#38 - Ref: Exhibit D/ Schedule 1/ Tab 6

Please provide compensation levels paid to Enersource's board members and executives including all benefits and expenses for the 2006 Actual year and an explanation and justification of these compensation levels. Please provide similar projections and explanations for the 2007 Bridge and 2008 Test years.

Response

Enersource Hydro's Board of Directors consists of:

- R. Herman;
- R. Rauber; and
- P. Quinn

Only Mr. Quinn receives compensation for sitting on this Board. This expense is included in Enersource's Administrative expenses. Please see the response to School Energy Coalition interrogatory # 44. For protection of privacy purposes, Enersource declines to provide information on the specific compensation to individual Executive Staff.

Interrogatory

#39 - Ref: Exhibit D/Schedule 2/Tab 7

For the 2006 tax year, please provide the following:

- I) Actual federal T2 tax return and supporting schedules filed with the Ministry of Finance;**
 - II) Actual Ontario CT23 tax return and supporting schedules filed with the Ministry of Finance;**
 - III) Financial statements that were submitted with the tax returns to the Ministry of Finance;**
 - IV) Any amended T2 or CT23 tax returns that may have been filed subsequent to the initial tax filing for 2006;**
 - V) Notices of Assessment, and any Notice(s) of Re-assessment, including Statement of Adjustments, received from the Ministry of Finance for the 2006 tax year; and**
 - VI) Any correspondence between the Ministry of Finance and Enersource regarding any tax items, or tax filing positions that may be in dispute, or under consideration or review.**
- IV) – There were no amendments to the 2006 Tax Filings.**
- VI) – The only correspondence from the Ministry of Finance was the receipt of the Notice of Assessment.**

Response

[See attachments.](#)

Interrogatory

#40 - D/S2/T7.1 - Capital Tax

In Exhibit A/S12/T7 rate base for 2007 is shown as \$487,241 and \$505,404 for 2008. Enersource did not use rate base in the calculation of capital tax. Instead it used \$520,758 for 2007 and \$534,122 for 2008 in the calculation of capital taxes.

- a. Please explain the source of these amounts used and how the numbers were calculated.
- b. Please explain why rate base was not used to represent taxable capital in the calculation of capital taxes.

Response

a)

	Test 2008	Budget 2007
PROVINCIAL CAPITAL TAX		
Paid Up Capital		
Retained Earnings	191,404	184,426
Reserves (Retirees Liability & Other)	3,534	3,054
Bonds	290,000	290,000
Line 371 - bump in CEC & CCA	25,302	19,484
Loans and Advances-Cons/Ret Deposits	21,382	21,295
Loans and Advances-Subdiv Adv/Dep	2,500	2,500
Total Net Paid Up Capital	534,122	520,758
Total Assets		
Total Assets per Balance Sheet	588,605	579,102
Adjustment for equity earnings in subs.	-	-
Total Assets	588,605	579,102
INVESTMENT ALLOWANCE		
Total Eligible Investments	-	-
Total Assets	588,605	579,102
Net Paid Up Capital	534,122	520,758
Investment Allowance	-	-
TAXABLE CAPITAL		
Net Paid Up Capital	534,122	520,758
Investment Allowance	-	-
Taxable Capital	534,122	520,758
PROVINCIAL CAPITAL TAX		
Taxable Capital	534,122	520,758
Capital Tax shelter	14,271	11,893
Taxable Capital after shelter	519,850	508,865
Provincial Capital Tax @ (0.285% - 2007:2008); (2006 - 0.3%)	1,482	1,450

b. The Taxable Capital represents the expected base upon which Capital Tax is computed for deriving our expected Payments in Lieu of taxes to be paid. It is computed on our actual Paid-Up Capital net of Capital Tax Shelter at a rate of 0.285% for 2007 – 2008.

Interrogatory

#41 - D/S2/T7.2. – Payments in Lieu of Taxes

a. The 2006 EDR Board Report, Chapter 7, page 61 specifically identified the recovery of regulatory assets and indicated that no tax provision is necessary in the regulatory calculation of the tax proxy to be included in rates. Gas utilities do not include movements of regulatory asset and liability balances in the calculation of regulatory taxes. The preparation of the company's actual tax return may require treatments of issues that are different than regulatory practice requires.

I) What regulatory instrument or practice has Enersource relied on to support its request to allow an addition to regulatory taxable income for the recovery of regulatory assets and amortization of regulatory assets?

II) Did Enersource expense regulatory assets to reduce the PILs tax proxy in prior applications? If not, please explain.

b. Please provide a continuity schedule to explain the various items in the lines entitled "Reserves from financial statements". Please explain each type of reserve and why it should be used in the regulatory tax calculation.

c. Please provide the tax schedule S8 calculations for undepreciated capital cost (UCC) and capital cost allowance (CCA) for the Historic, Bridge and Test Years by class using the 2006 tax return schedules as the format.

d. Please provide the application capital expenditure exhibit references for the additions to UCC in the S8 calculations requested above for Historic Bridge and Test Years.

e. Please provide the calculation of the cumulative eligible capital deduction for the Historic, Bridge and Test Years.

f. Please provide a tax forecast for the 2007 Bridge Year similar to that for the 2008 Test Year as shown in D/S2/T7.2.

g. Please provide a table and explanations for the amounts shown as "Other additions" of \$468 for 2008. Please provide explanations for similar items in the 2007 Bridge Year calculations.

h. If any of these "other additions" relate to non-deductible expenses for tax purposes, please explain why these non-deductible expenses would not be to the account of the shareholder only?

i. Please provide a table and explanations for the amounts shown as "Other deductions" of \$250 for 2008. Please provide explanations for similar items in the 2007 Bridge Year calculations.

- j. Please provide the application section reference for the AFUDC amount of \$302. If the calculations are not provided elsewhere in this application, please provide the detailed calculations of the AFUDC dollar amount including the applicable capital expenditures and the interest rate used.**
- k. Please show the calculation of the income tax rate used in the calculation of 2008 PILs income taxes.**
- l. Please explain why Enersource did not use the known tax rate of 34.5% for the 2008 Test Year.**

Response

All dollar amounts in 000's

a) I) Enersource relies on the fundamental principle that PILs are a flow-through in customer rates. All PILs payments should be recovered through distribution rates, as demonstrated by the OEB's requirement to record PILs revenue variances resulting from any changes in tax rates and tax policies for recovery/disbursement to customers in future periods.

The PILs treatment of the regulatory asset recoveries in this application is consistent with the method presented in Enersource's 2006 EDR rate application. This method was subsequently approved by the OEB.

Also, this treatment of recoveries is consistent with the OEB's 2004 Decision regarding Enersource's recovery of regulatory assets and transition costs.

- a) II) In its 2006 rate application, Enersource did not record a deduction of expenses that were deferred for future rate recovery. However, this did not result in Enersource overearning its allowed market adjusted rate of return.
- b) Please see attached schedule.
- c) Please see attached schedule.
- d) Please see attached schedule.
- e) Please see attached schedule.
- f) Please see attached schedule.
- g) The "Other Additions" in the 2008 PILs calculation are as follows:

Amortization of debt issue costs	\$434
Non-deductible meals (50%)	<u>34</u>
Total	\$468

- h) The "Other Additions" in the 2007 PILs calculation are as follows:

Amortization of debt issue costs	\$434
Non-deductible meals (50%)	<u>33</u>

Total \$467

- i) The “Other Deductions” in the 2008 & 2007 PILs calculations relates to an estimated realized loss on foreign exchange in both years.
- j) Please note that this amount was added back to Net Income (Exhibit D/ Schedule 2/ Tab 7.2). The AFUDC amount is estimated based on an average CIP balance of \$5,830 with an applied rate of 5.18%.
- k) The interest rate used in the calculation of the 2008 PILs income taxes is 36.12%, which is the current income tax rate.
- l) Enersource elected to use the current income tax rate.

Interrogatory

#42 - Ref: ExG/Sch2/Tab3/p1

Please provide a brief description, describing the component entries, of all outstanding individual deferral and variance accounts being applied for disposition in this application.

Response

Ontario Price Credit – Account 1525 - Miscellaneous Deferred Debits, sub account Payments to Customers. This amount is related to the cost of rebate cheque production, postage and manpower costs for the Ontario Price Credit of March 2006

LCT Over Recovery – Account 1592 - 2006 PILS and Tax Variances. The amounts recorded in 1592 are related to:

1) PILs deferral due to a re-assessment arising from prior years Tax Audit in 2006; and
2) LCT over-recovery from May 1, 2006 to April 30, 2007 as the Federal Government repealed the Federal Large Corporation Tax (“LCT”) in its 2006 Budget retroactive January 1, 2006.

Deferred OEB Costs - Account (1508) is related to other regulatory assets, OEB Costs Assessments Deferral for January 1, 2005 to December 31, 2005 and January 1, 2006 – April 30, 2006.

OMERS Pension Deferral - Account (1508) is related to other regulatory assets, OMERS Pension Contributions Deferral for January 1, 2005 to December 31, 2005 and January 1, 2006 – April 30, 2006.

Interest on Regulatory Assets – Account 1590 Recovery of Regulatory Asset Balances. This is the net interest on account 1590 through April 30, 2008 that will be outstanding at the expiration of the Recovery of Regulatory Asset Balances on April 30, 2008 that were posted to account 1590.

Retail Cost Variance Retail - RCVA_{Retail} – Account 1518. This variance account is established to record the difference between the amount billed and the incremental costs of providing retail services other than those related to a Service Transaction Request (STR).

Retail Cost Variance STR – RCVA_{STR} - Account 1548. This variance account is established to record the difference between the amount billed in relation to a STR and

the incremental costs of providing the initial screening and actual processing services for the STR.

Retail Settlement Variances:

Wholesale Market Service Costs - RSVA_{WMS} – Account 1580 - This account is used to record the net of:

i) the amount charged by the Independent Electricity System Operator (“IESO”) , based on the settlement invoice, for the operation of the IESO administered markets and the operation of the IESO – controlled grid (as defined in the *Electricity Act, 1998*) specified by the Board,

AND

ii) the amount billed to customers using the Board-approved Wholesale Market Service Rate.

If applicable, embedded distributors shall also use this account to record the net difference between the amount charged by the host distributor (based on the settlement invoice) for wholesale market services and the amount billed to customers using the Board-approved Wholesale Market Service Rate.

A sub-account is used to separately record any related carrying charges.

Wholesale Market Service Costs – RSVA_{One Time} – Account 1582 - This account is used to record the net of:

i) the amount charged by the Independent Electricity System Operator (“IESO”) , based on the settlement invoice, for Wholesale Market Service Charges, specified by the Board (these charges are not normally already incorporated in the Wholesale Market Service Rate),

AND

ii) the amount billed to customers for the same services using the Board-approved Rate.

A sub-account is used to separately record any related carrying charges.

Network - RSVA_{NW} _ Account 1584 - This account is used to record the net of:

i) the amount charged by the Independent Electricity System Operator (“IESO”) , based on the settlement invoice, for transmission network services,

AND

ii) the amount billed to customers for the same services using the Board-approved Transmission Network Charge Rate.

If applicable, embedded distributors shall also use this account to record the net difference between the amount charged by the host distributor (based on the settlement invoice) for transmission network services and the amount billed to customers using the Board-approved Transmission Network Charge Rate.

A sub-account is used to separately record any related carrying charges.

Connection - RSVA_{CN} - Account 1586 - This account is used to record the net of:

i) the amount charged by the Independent Electricity System Operator (“IESO”), based on the settlement invoice, for transmission connection services,

AND

ii) the amount billed to customers for the same services using the Board-approved Transmission Connection Charge Rate.

If applicable, embedded distributors shall also use this account to record the net difference between the amount charged by the host distributor (based on the settlement invoice) for transmission connection services and the amount billed to customers using the Board- approved Transmission Connection Charge Rate.

A sub-account is used to separately record any related carrying charges.

Power - The RSVAPower account 1588 – This account is used for the purpose of recording the “net

difference” in energy cost only. “Net difference” refers to the difference between the amount charged by the IESO, host distributor or embedded generator based on the settlement invoice for the energy cost and the amount billed to customers for the energy cost. Note that these differences could be composed of differences in energy price and/ or energy quantities as well as the difference between estimated and actual line loss factors.

LV Charges – Distribution Wheeling/ Low Volume (LV) Service

Some distributors supply power to embedded distributors through distribution facilities and other facilities. As a result, the host distributors must apply to the Board for a rate to recover the costs associated with providing this service to the embedded distributors. Similarly, embedded distributors may apply for a rate to recover these charges from their customers. These LV charges are for the 2008 Test Year to be recovered from customers.

LRAM (Lost Revenue Adjustment Mechanism) and SSM (Shared Savings Mechanism): The Board’s RP-2004-0188 Electricity Distribution Rate Handbook Report provides the authorization to seek recovery of LRAM and SSM. This Report refers to the Board’s December 2004 Decision RP-2004-0203, concluding that a retrospective LRAM was appropriate for CDM expenditures and that a distributor shareholder incentive was an appropriate way to encourage distributors to pursue CDM programs. LRAM refers to the CDM-related load reductions for each customer class by year multiplied by the authorized variable distribution rate for that customer class. SSM is 5% of the net TRC (Total Resource Cost guide) benefits for each program based on energy savings.

Interrogatory

#43 - Ref: ExG/Sch2/Tab3/Pg1

- a. Are you currently using account 1590?**
- b. If the answer to (a) is no, then please explain in detail why?**
- c. If so, have you transferred previous Board-approved amounts for regulatory asset recovery to 1590?**
- d. Please update the appropriate schedules to reflect any necessary adjustments to incorporate account 1590.**

Response

- a) Yes, Enersource currently uses account 1590.
- b) Not applicable
- c) Yes, as indicated as a requirement in the Board's letter of November 28, 2006 to electricity distributors regarding its approval of prescribed accounting interest rates policy for regulatory accounts. Amounts approved as part of the 2006 rates application process for each regulatory asset/liability account on a final basis for disposition in distribution rates should be posted to account 1590, Recovery of Regulatory Assets, effective on May 1, 2006. The offsetting entry is to the related regulatory asset/liability account(s). The exception to this was the 2004 OEB Assessed Costs and 2004 OMERS Pension Costs deferral approved for Recovery in the 2006 EDR Application, are recovered under account 1508 and are identifiable and tracked separately under this account.
- d) Account 1590 has not been adjusted to reflect the transfer of account 1508 of the recovery of the 2004 OEB Assessed Costs and 2004 OMERS Pension Costs Deferral as these costs are identifiable and tracked under account 1508.

Interrogatory

#44 - Ref: ExG/Sch2/Tab3/Pg1

Enersource is applying for disposition of regulatory variance accounts as per schedule Exhibit G/Schedule 2/Tab 3. These totals do not correspond to totals in reported to the Board as per 2.1.1 of the Reporting and Record Keeping Requirements for the period ending December 31st, 2006. Please complete the attached continuity schedule and provide a further schedule reconciling the continuity schedule with the amounts requested for disposition on ExG/Sch2/Tab3/Pg1.

Response

[Please see the attachments.](#)

Interrogatory

#45 - Ref: ExG/Sch2/Tab4/Pg1

Enersource has provided some aggregated information on the accounts being applied for disposition, but no individual account numbers or balances have been listed.

- a. Please state which accounts, individual balances, and the composition of those balances, that are being applied for disposition?**
- b. Please provide an un-aggregated detailed method of recovery, including bill impact, for each account that is being applied for disposition. For example, account 1592 has a balance of \$xx, will be allocated to rate classes via xx, which will have an impact of xx.**

Response

[Please see the attachments.](#)

Interrogatory

#46 - Ref: ExG/Sch2/Tab4/Pg1

- a. Please explain the unforeseen cost associated with the Ontario Price Credit administration cost being requested for disposition?**
- b. What period does it relate to?**

Response

Ontario Price Credit – Account 1525 - Miscellaneous Deferred Debits, sub account Payments to Customers. This amount is related to the cost of rebate cheque production, postage and manpower costs for the Ontario Price Credit incurred from RBC Global Services for the cost of rebate cheques and from D&A Collection Corporation for manpower costs for Ontario Price Credit reimbursement adjustments. This is accordance with OEB Letter dated December 13, 2005 – Re: Payment, Reporting and Accounting in Relation to the “Ontario Price Credit”.

These costs were incurred in March 2006 in line with the requirements of the OEB Letter which stated that July 31, 2006 was the last date by which payments must be made by distributors and Participating Retailers to low-volume and designated consumers under sections 11 and 12, respectively, of the Regulation.

Interrogatory

#47 - Ref: ExG/Sch2/Tab3/Pg1

What are the interest rates being used to calculate carrying charges for each regulatory deferral and variance account for the period from January 1, 2005 to present?

Response

[Please see the attachment.](#)

Interrogatory

#48 - Ref: Exhibit D, Schedule 1, Tab 9.2 and Exhibit H, Schedule 4, Tab 1, Page 2 of 2

The table titled “Total Loss Factor - per OEB 2006 EDR Handbook” the 1st reference provides “Loss Factor” for 2002 to 2006. The 2nd reference provides total loss factors for secondary and primary customers for customers <5,000 kW and >5,000kW.

a. In the 1st reference, with respect to “Loss Factor”:

I) Please indicate whether this refers to Total Loss Factor (TLF) as implied by the table’s title or Distribution Loss Factor (DLF). If it is the former, please provide values for the underlying DLF for 2002 to 2006, and if it is the latter, please provide values for the corresponding TLF for 2002-2006. In either case, please provide the Supply Facilities Loss Factor (SFLF) used to convert DLF to TLF.

II) Please explain the calculation method to obtain this factor for 2002-2006.

III) Please provide an explanation for the 2006 increase in this factor and its 3-year moving average.

b. Please indicate which of the four factors for 2008 provided in the 2nd reference is comparable to the loss factor provided in the 1st reference.

Response

- a)
 - i) Enersource’s DLF is provided on the line titled “Loss Factor”. Consistent with the Loss Factor methodology used in the 2006 EDR a 3 year moving average has been computed and is provided on the line titled “3 year average Loss Factor”.
 - ii) Enersource relied on the 2006 EDR methodology.
 - iii) Please refer to Exhibit D/Schedule 1/Tab 5.
- b) Enersource has not proposed any change to the TLF – Secondary Metered Customer >5,000 kW or to the TLF – Primary Metered Customer >5,000 kW.

Interrogatory

#49. Ref: Exhibit D /Tab 10 /Schedule 1 /Pages 1 to 6

The Board's "Filing Requirements for Transmission and Distribution Applications" issued on November 14, 2006, outlines on Page 39 the information that is required when filing an application for LRAM or SSM.

Please provide the following:

- a. kW or kWh impacts net of free riders for each program and each rate class;**
- b. Verification of participation levels; and**
- c. Duration of the programs in years and months.**

Response

- a. kW or kWh impacts net of free riders for each program and each rate class are listed in the attached spreadsheet;
- b. Verification is based on a number of documents, depending on the particular program. For example, sign-up sheets for WH Tune-ups, Mississauga Library monthly reports, Special Events/LED Drop-off promotional pieces, Retailer Coupon OPA's reports, invoices, customers' applications, etc. A sample of the Water Heater tune-up program verification process is attached.
- c. See attached spreadsheet.

Interrogatory

#50. Ref: Exhibit D/Tab 10/Schedule 1/Pages 1-6

Please identify any distribution rate funded residential, commercial, or industrial program(s) where load impacts were not calculated using the measure-specific values in the Board's Total Resource Cost ("TRC") Guide. For any program that did not use the measure-specific values in the TRC Guide, please provide the supporting documentation on how these load impacts were calculated.

Response

All load impacts were calculated using OEB Table measure-specific values, found in the TRC Guide Oct-05 revision. Some programs' impacts were based on customer consultants' calculations, which we verified for accuracy. For example, some adopted measures (e.g., 13W CFLs) were not included in the TRC Table, but we followed the TRC Guide prescribed methodology in confirming savings.

Interrogatory

#51. Ref: Exhibit D/Tab 10/Schedule 1/Page 4

a. Please explain why Enersource Hydro Mississauga Inc. (“Enersource”) did not adjust the Lost Revenue Adjustment Mechanism (“LRAM”) amounts for free riders, given that the Board’s EB-2007-0096 Decision and Order, issued September 11, 2007, confirmed that free riders must be included in the calculation of the LRAM.

b. Please provide the calculations, inputs and assumptions that were used to determine the LRAM amount.

Response

Enersource will no longer request an adjustment for lost revenue related to free riders.

The model accounts for load impacts both net and gross of freeriders and both annual and lifetime savings, taking into account the measure-specific life expectancy.

The basis for calculations, inputs and assumptions can be found in the attached spreadsheet. Enersource “phased in” all projected savings, prorating annual savings according to the month they actually started to occur.

Please refer to the response to Board staff interrogatory #49.

Interrogatory

#52. Ref: Exhibit D/Tab 10/Schedule 1/Page 3

a. Please explain why Enersource finds it appropriate to gross-up the Shared Savings Mechanism (“SSM”) amount for taxes, given that the Board’s EB-2007-0096 Decision and Order confirmed that it was not appropriate to do so.

b. Please provide the calculations, inputs and assumptions that were used to determine the SSM amount.

Response

a. Enersource will no longer request the gross-up of SSM for taxes.

b. Enersource followed the OEB TRC Guide and used the SeeLine TRC model. The basis for calculations, inputs and assumptions can be found in the attached spreadsheet.

Please refer to the response to Board staff interrogatory 49.

Interrogatory

#53. Ref: Exhibit D/Tab 10/Schedule 1/Pages 1-6

Please confirm if any programs were jointly sponsored with other regulated distributors. If so, please identify those programs, and confirm that the apportioned savings are in accordance with the TRC Guide and the Board's EB-2005-0523 Decision.

Response

All our programs – while jointly developed with CLD members – were implemented independently from other regulated distributors.

Interrogatory

#54. Ref: Exhibit D/Tab 10.3/Schedule 2

In its Report of the Board on the 2006 EDR Handbook, issued May 11, 2005, the Board stated:

“There has been considerable discussion in this proceeding as to whether CDM expenditures on the utility side should be differentiated from customer-side expenditures. The Board recognizes that conservation programs should have a balance between the two. It is important to recall however, the Board’s earlier finding that the SSM incentive does not apply to utility-side investments. The Board previously ruled with respect to the 2005 SSM that the inclusion of capitalized assets into rate base provides sufficient incentives. The Board continues to hold that view.”

a. Please confirm if Enersource is claiming SSM amounts for utility-side programs.

1) If the answer to a) is yes, please provide a revised SSM amount with SSM amounts for utility-side programs removed.

b. Given the Board’s statement that the “SSM incentive does not apply to utility-side investments” and “inclusion of capitalized assets into rate base provides sufficient incentives”, please explain why Enersource finds it appropriate to include smart meter calculations in the SSM amount?

Response

- a. The only utility-side program is Voltage Profile Management; Enersource has not included a net benefit attributable to this program when quantifying the SSM.
- b. At the time the handbook was issued these programs were already in place (Residential Smart Meters and Commercial Smart Meters); they have been removed from the SSM calculation.

Interrogatory

#55 - Ref: Exhibit G /Schedule 2 /Tab 6 /Page 3

In the first paragraph of page 3, Enersource Hydro Mississauga Inc. (“Enersource”) states “Consistent with the Decision [with Reasons in EB-2007-0063], Enersource proposes to calculate the revenue requirement for Smart Meters as they are installed on an ongoing basis effective May 1, 2008 through a sub-account within account 1555 – Smart Meter Variance Account. Enersource also proposes to recognize the return on a monthly basis by adjusting USoA accounts 1555 to 4080. Enersource also seeks to recover a 2008 Smart Meter Rate Adder (“2008 SMRA”) of \$0.57/metered-customer/month.”

a. Please confirm that the smart meter investment amounts for smart meter installations which formed the basis for the calculation of the revenue requirement for smart meters are not incorporated into the fixed asset accounts and the rate base.

In the second paragraph of page 3, Enersource states “The derivation of Enersource’s proposed 2008 Smart Meter revenue requirement is provided at ExG/Sched2/Tab7. It has been developed to support the recovery of Enersource’s investment in Smart Meters for the 2008 Test Year and to return the over-recovery of revenue through the 2006 and 2007 SMRA. The proposed 2008 SMRA of \$0.57 is the difference between, a rate adder of \$1.32/metered-customer/month and a return of \$0.75/metered-customer/month.”

b. Please confirm that Enersource proposes to recover all of its smart meter costs through the proposed 2008 SMRA which is expected to be effective May 1, 2008, without incorporating any smart meter costs into its permanent distribution rate base.

Response

- a. Enersource confirms that there are no amounts for smart meter installations that are included in the revenue requirement for the smart meter rate adder.
- b. Enersource proposes to recover the revenue requirement associated with smart meter through the proposed 2008 Smart Meter Rate Adder. Enersource proposes to recognize the return on a monthly basis by adjusting USoA accounts 1555 to 4080. Until the Board determines the methodology for adjusting rate base

annually for the investment in smart meters Enersource will continue to rely on and adjust the Smart Meter Rate Adder to recover the associated revenue requirement.

Interrogatory

#56 - Ref: Exhibit G /Schedule 2 /Tab 8

On the first line of Exhibit G /Schedule 2 /Tab 8 (table “Smart Meter Rate Calculation”), Enersource provides the values for Net Fixed Assets with respect to smart meter installations for the years 2006 through 2008.

a. Please provide the Gross Fixed Asset amounts and the associated number of smart meter installations for the years 2006 through 2008.

b. Please confirm whether the investment amounts for smart meters during these years will meet or exceed the “minimum functionality” criteria which formed the basis in the Board’s August 8, 2007 Decision with Reasons in EB-2007-0063 to allow the recovery of smart meter capital costs. In that Decision, the Board determined that there were fourteen cost categories in relation to “minimum functionality” that were set out in Appendix “A”. Are any of the investment costs outside of these fourteen cost categories, if so please describe these costs and why Enersource is seeking to recover them. If any of Enersource’s proposed smart meter expenditure items are beyond the “minimum functionality” criteria, please provide, for each year from 2006 to 2008, the investment cost breakdowns for “minimum functionality” and “beyond minimum functionality” cost categories.

Response

a. See attached Excel spreadsheet.

b. Enersource smart meter systems do not exceed the minimum functional requirements and all 14 cost categories meet these criteria. Enersource is implementing smart meters in accordance with the evidence that was submitted to the Board in EB-2007-0063.

Interrogatory

#57 - Ref: Retail Transmission Rates

The Wholesale Network Transmission Rate will decrease 28% effective November 1 2007.

I) For each rate class, please provide a revised RTR – Network Service Rate that would be revenue neutral over the 12 month period beginning May 1, 2008. (i.e. The amount collected by the revised RTR – Network Service Rate for each rate class should equal the amount paid for the Wholesale Transmission Rate.)

The Wholesale Connection Transmission Rate will decrease 18% and the Wholesale Transformation Connection Transmission Rate will increase 7% effective November 1 2007.

II) For each rate class, please provide a revised RTR – Line and Transformation Connection Service Rate that would be revenue neutral over the 12 month period beginning May 1, 2008. (i.e. The amount collected by the RTR - Line and Transformation Connection Service Rate for each rate class should equal the amount paid for the Wholesale Connection Transmission Rate and the Wholesale Transformation Connection Transmission Rate.)

Deferral and Variance Accounts 1584 & 1586

Utilities have been required to provide information on Account 1584 RSA NW and 1586 RSVA CN to the Board as part of the quarterly RRR filings. The Board may need confirmation of the actual balances in these accounts in order to set a rate rider for the RTS rates.

III) What are your current balances for Accounts 1584 RSA NW and 1586 RSVA CN?

IV) Please explain how your balances in Accounts 1584 RSA NW and 1586 RSVA CN have trended or fluctuated since January 1 2005.

V) Assuming your RTR – Network Service Rate for each rate class is revenue neutral, please provide the rate riders you would recommend beginning May 1 2008, and the duration in months for each rate rider, to reduce the balance in Account 1584 RSVA NW to a \$0 balance. Please provide an explanation for the recommended duration of the rate riders.

VI) Assuming your RTR - Line and Transformation Connection Service Rate for each rate class is revenue neutral, please provide the rate riders you would recommend beginning May

1 2008, and the duration in months for each rate rider, to reduce the balance in Account 1586 RSVA CN to a \$0 balance. Please provide an explanation for the recommended duration of the rate riders.

Response

In the subject application, Enersource has proposed the return to customers of the balances recorded as of December 31, 2006 in Account 1584 and Account 1586. Enersource will review its Retail Transmission Service Rates and address any changes in an update to be filed at a later date.

Interrogatory

#58 - Ref: Exhibit E/Schedule 1/Tab 1 – Short-Term Debt

Enersource states: “Enersource’s proposed deemed capital structure does not include a short term debt component. This is because Enersource’s actual capital structure does not rely on short term debt and because Enersource’s actual capital structure is appropriate for rate making purposes.”

Section 2.1.1 of the Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation Mechanism for Ontario’s Electricity Distributors (the “Board Report”) states that: “The Board has determined that short-term debt should be factored into rate setting, and that a deemed amount should be included in the capital structures of electricity distributors. The short-term debt amount will be fixed at 4% of rate base.” [Emphasis in Original]

a. Please provide Enersource’s reasons for proposing that the Board should use its actual capital structure rather than a deemed capital structure in accordance with the guidelines documented in the Board Report.

b. Please re-estimate the weighted average Cost of Capital including a short-term debt component of 4% and a short-term debt rate of 4.59%, as published for 2007 Q3 on the Board’s web site under “Prescribed Interest Rates for Approved Accounts of Gas Utilities and Electricity LDCs and Other Rate-Regulated Entities Approved by the Board”

(http://www.oeb.gov.on.ca/html/en/industryrelations/rulesguidesandforms_regulatory_prescribedinterestrates.htm).

c. Please provide the variance analysis of the return on rate base and revenue requirement comparing Enersource’s proposal excluding the short-term debt component versus the scenario contemplated in b).

Response

- a) Enersource’s reasons for relying on its actual capital structure for rate making purposes are provided at ExhibitE/Schedule1/Tab1/p.2. Briefly, Enersource’s position is that its historic capital structure is not inefficient. This position is supported by the Bond and Credit Rating Reports filed in this proceeding that do not take issue with the capitalization. Enersource notes that its capital structure is aligned with the Board’s previously determined deemed capital structure, which has not been determined to be inefficient. The Board’s Report

is a generic guideline and Enersource has applied it, except for the short term debt component. Since Enersource does not rely on short term debt and does not propose to, it would be inappropriate to include a deemed short term component in Enersource's deemed capital structure.

b) The requested data is provided in the table below.

	2008 as proposed			2008 revised		
Capital Structure	Amount	Proportion		Amount	Proportion	
Long Term Debt	303242.4	60%		283026.2	56%	
Short Term Debt	0	0%		20216.16	4%	
Equity	202161.6	40%		202161.6	40%	
Total	505404	100%		505404	100%	
Cost of Capital - by component						
Long Term Debt	6.44%			6.44%		
Short Term Debt	0%			5%		
Equity	9%			9%		
Computed Weighted Average Cost of Capital	Weight	Cost	WACC	Weight	Cost	WACC
Long Term Debt	60.00%	6.44%	3.86%	56.00%	6.44%	3.61%
Short Term Debt	0.00%	0.00%	0.00%	4.00%	4.59%	0.18%
Equity	40.00%	9.00%	3.60%	40.00%	9.00%	3.60%
Total	100.00%		7.46%	100.00%		7.39%

c) The requested variance analysis is provided in the table below.

	2008 as proposed	2008 revised	Difference
Revenue Requirement	124,108	123,734	374
Return on Rate Base	37,723	37,349	374

Interrogatory

#59 - Re: Exhibit E/Schedule 3/Tab 1 – Forecasts of Government of Canada Bond Yields by the Conference Board of Canada and the Royal Bank of Canada

Please provide copies of the source documents for the Conference Board of Canada, December 2006 and Royal Bank of Canada Economic Forecasts, July 2007, forecasts of 2008 economic data that Enersource has relied on to estimate its proposed ROE.

Response

[Please see attached:](#)

- [Excerpt from Toronto Hydro's 2008 EDR Application that provides the Conference Board of Canada December 2006 forecast; and](#)
- [The Royal Bank of Canada July 2007 Forecast.](#)

Interrogatory

#60 - Re: Exhibit E/Schedule 1/Tab 1 – Return on Equity

Enersource states that it “proposes a 9.00 per cent rate of return for rate making purposes in the 2008 Test Year, based on the average of estimates for 2008 based on applying the Board ROE formula to economic forecast data from the Conference Board of Canada (December 2006) and the RBC Economic Report (July 2007)”.

- a. Is Enersource proposing that the 9.00% should be used instead of updating the ROE with January 2008 data from Consensus Forecasts and the Bank of Canada, in accordance with the methodology documented in Appendix B of the Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation (the “Board Report”), issued December 20, 2006?**
- b. If the answer to a) is that Enersource is not proposing to update the ROE in accordance with the Board Report, please state the rationale for departing from the methodology in the Board Report?**
- c. Please explain, with reasons, if Enersource believes that the two sources of economic forecasts used are more reliable and accurate than Consensus Forecasts, and hence should be preferred for setting Enersource’s ROE for rate-making purposes for 2008.**

Response

- a) Enersource seeks an opportunity to earn a rate of return on equity of 9%. This rate of return has been computed using the Cannon methodology and using Conference Board and Royal Bank of Canada forecasts; it is a pragmatic approach that utilizes the best available information at the time of preparing the rate application.
- b) Enersource is aware of the findings of Concentric Energy Advisors, Inc.’s study of the allowed rates of return for natural gas distributors in Canada; Enersource’s decision on filing any updates to its proposed rate of return will be informed by the Board’s considerations of these findings.
- c) Enersource did not have ready access to the Board’s Consensus Forecast data and relied on data provided by one of its lead bankers.

Interrogatory

#61 - Ref: Ex G /S1/T1

a. Please produce a cost allocation study based on the 2008 test year by incorporating the following changes to the Informational Filing Run 1:

I) Updated versions of Sheets I3 'Trial Balance Data' and I4 'Break Out Assets' in sufficient detail to reflect significant differences between the inputs to the Informational Filing model and the corresponding inputs to 2008 expenses and rate base respectively:

II) An update to Sheet I6 'Customer Data' row 29 (Ref: Exhibit G / Schedule 1 / Tab 1 / Page 1)

III) An update to Sheet I6 'Customer Data' rows 33 – 47 using forecast numbers of customers, connections and bills;

IV) An update to Sheet I8 'Demand Data' using the class load profiles supplied by Hydro One together with the Applicant's forecast energy amounts (Ref: Informational Filing Page 9, and Exhibit B / Schedule 2 / Tab 2 / Page 1)

V) Any other updates or refinements to input sheets that the Applicant may choose to make to the Informational Filing, together with a list and brief description of such changes

In addition to the worksheets identified above, the response must include Sheets 01 'Revenue to Cost RR', 02 'Fixed Charge / Floor / Ceiling', and E2 'Allocators'. (Please note that an exact reconciliation of 100% in Sheet 01 cell C 70 is desirable but not necessary for the response to this interrogatory.)

Response

Enersource notes that the Board is involved in a continuing process to review the CAR-IF. In the meantime, Enersource has relied on the 2006 EDR methodology to assign responsibility for the proposed 2008 revenue requirement.

Interrogatory

#62 - Ref: Exhibit G / Schedule 2 / Tab 3

Please confirm that the return of \$5.118 million is effected by means of rate riders applied to the volumetric charge determinant of each class, and not by means of any adjustment to the monthly fixed charge of any class.

Response

Enersource confirms that the return of \$5.118 million is effected by means of rate riders applied to the volumetric charge determinant of each customer class and not by means of any adjustment to the monthly fixed charge of any customer class.

Interrogatory

#63 - Ref: Exhibit H/Schedule 1 /Tab 1 /Page 1 and Exhibit H/Schedule 5

a. In Schedule 5, please confirm that the percentage increase in the volumetric charge is nearly uniform across all of the classes (except for Streetlighting) at an amount ranging from 13.23% to 13.51%.

b. In Schedule 5, please confirm that the percentage increase in the monthly service charge is not uniform across the same classes, ranging from 6.00% to 13.12%.

c. Please reconcile the responses in parts a) and b) with the statement in Schedule 1 that the Applicant “proposes to maintain the current rate design”.

Response

- a) Enersource confirms that the percentage increase in the volumetric charge is nearly uniform across customer classes as noted above, except for Street Lighting.
- b) Enersource confirms that the percentage increase in the monthly service charge is not uniform across customer classes.
- c) Enersource has maintained the current rate design in that:
 - no new rates or charges are proposed;
 - no new customer classes are proposed;
 - no customer class has been eliminated;
 - no changes to Transformer Allowance .is proposedThe change in the fixed charge is driven by 2 factors – the responsibility for the revenue requirement and the responsibility for the recovery of the 2008 Smart Meter Rate Adder.

Interrogatory

#64 - Ref: Exhibit G/ Schedule 2/Tab 5/ Table 1, and Exhibit H/Schedule 5

The following questions refer to revenue to cost ratios found in the Informational Filing. If the results of the cost allocation study based on the 2008 test year are substantially different from the ratio amounts referenced below, please reference the updated results as appropriate.

- a. Please provide a justification for increasing rates to the Small Commercial class in nearly the same proportions as all other classes, in light of its already high revenue to cost ratio of approximately 150%.**
- b. Please provide a justification for increasing the Monthly Service Charge by 13.12%, the largest proportion of all classes except for Streetlighting, in light of its already high revenue to cost ratio of approximately 137%.**
- c. Please provide a justification for increasing the rates for Streetlighting by a percentage very little more than all other classes, in light of its low revenue to cost ratio of approximately 25%.**

Response

As indicated in the response to Board staff interrogatory #61 Enersource has relied on the 2006 EDR methodology to assign responsibility for the proposed 2008 revenue requirement.

Please note that Enersource anticipates shifts in consumption profiles between and among its customer classes as a result of the implementation of several government initiatives (eg., Time of Use commodity prices, Standard Offer Program, Conservation and Demand Management) that may result in material changes to cost allocation factors.

- a) Enersource proposes to increase the distribution rates charged Small Commercial customer class in similar proportion to the rate increase experienced by other customer classes so that to preserve proportional responsibility. Please note that the Small Commercial customer class includes Flat Rate customers and unmetered loads and there are concerns about the veracity of the cost:revenue ratio observed for this customer class that were identified in the Cost Allocation Working Group (eg., due to lack of metered data, use of connection versus customer number data).

- b) Enersource assumes that this question pertains to the proposed adjustment to Large User rates. Please note that the computed revenue:cost ratio and its treatment of Transformer Allowance credits has been questioned by other distributors. The fixed rate charged Large Users has been adjusted consistent with the adjustment to all other customer classes. Enersource proposes to increase the distribution rates charged the Large User customer class in similar proportion to the rate increase experienced by other customer classes so that to preserve proportional responsibility.
- c) Enersource proposes to increase the distribution rates charged Street Lighting customer class in similar proportion to the rate increase experienced by other customer classes to preserve proportional responsibility. Please note that Street Lighting loads are not metered and the computed revenue:cost ratios are sensitive to the number of individual devices versus the number of connections.

Interrogatory

#65 - Ref: Exhibit H, Schedule 5

The three tables for “Small Commercial and USL” in the Bill Impact section, show the monthly distribution (kWh) charge as follows:

Monthly Consumption (kWh)	Monthly Distribution (kWh) Charge – 2007 Bill	Monthly Distribution (kWh) Charge – 2008 Bill
15,000	\$385.50	\$436.50
40,000	\$1,028.00	\$1,164.00
100,000	\$257.00	\$291.00

Please explain why the monthly distribution charge for consumption 100,000 kWh/month is 25% of the same charge for consumption 40,000 kWh/month and 67% of the same charge for consumption 15,000 kWh/month.

Response

Small Commercial and USL

Consumption	100,000 kWh	Loss Factor	1.036
	0 kW		

	2007 BILL			2008 BILL			IMPACT		
	Volume	RATE \$	CHARGE \$	Volume	RATE \$	CHARGE \$	\$	%	% of Total Bill
Monthly Service Charge			\$ 15.32			\$ 16.45	\$ 1.13	7.39%	0.14%
Distribution (kWh)	100,000	\$ 0.0257	\$ 2,570.00	100,000	\$ 0.0291	\$ 2,910.00	\$ 340.0000	13.23%	24.89%
Distribution (kW)	0	\$ -	\$ -	0	\$ -	\$ -	\$ -	0.00%	0.00%
Regulatory Assets (kWh)	10,000	\$ 0.0008	\$ 8.00	10,000	\$ -0.0046	\$ -46.00	\$ (54.00)	-675.00%	-0.39%
Regulatory Assets (kW)	0	\$ -	\$ -	0	\$ -	\$ -	\$ -	0.00%	0.00%
Sub-Total			\$ 2,593.32			\$ 2,880.45	\$ 287.13	11.07%	24.64%
Other Charges (kWh)	103600	\$ 0.0231	\$ 2,393.16	103600	\$ 0.0231	\$ 2,393.16	\$ -	0.00%	20.47%

Other Charges (kW)	0	\$ -	\$ -	0	\$ -	\$ -	\$ -	0.00%	0.00%
Cost of Power Commodity (kWh)	750	\$ 0.0530	\$ 39.75	750	\$ 0.0530	\$ 39.75	\$ -	0.00%	0.34%
Cost of Power Commodity (kWh)	102,850	\$ 0.0620	\$ 6,376.70	102,850	\$ 0.0620	\$ 6,376.70	\$ -	0.00%	54.55%
Total Bill before Taxes			\$ 11,402.93				\$ 287.13	2.52%	100%
GST (2007 - 6%, 2008 - 6%)			\$ 684.18				\$ 17.23	2.52%	
Total Bill after Taxes			\$ 12,087.11				\$ 304.36	2.52%	

Upon inspection it was determined that the results for the 100,000 kWh case were incorrectly computed using 10,000 kWh; corrected tables are provided.

The 100,000kWh / month for consumption (used 10,000 kWh) should be 24.89%:

Interrogatory

#66 - Ref: Exhibit H/Schedule 5 and Exhibit H /Schedule 3 /Tab 1 / Page 1

The table for “Streetlights” in the Bill Impact section in the 1st reference shows the distribution rate for 2008 as \$3.2376/kW and monthly service charge as \$0.42. The table titled “Proposed Base Distribution Rates” in the 2nd reference shows the distribution rate for 2008 for “Street Lighting” as \$3.1067/kW and monthly service charge as \$0.41

a. Please indicate which of the two distribution rates (\$3.2376/kW vs. \$3.1067/kW) for streetlights is correct.

b. Please indicate which of the two monthly service charges (\$0.42 vs. \$0.41) for streetlights is correct.

Response

ExhibitH/Schedule3/Tab1 is correct, the proposed variable distribution rate for Street Lighting is \$3.1067/kW and the proposed fixed distribution rate is \$0.41/connection/month.

<i>Consumption</i>	70 kWh	<i>Loss Factor</i>	1.036
	2 kW		

	2007 BILL			2008 BILL			IMPACT		
	Volume	RATE \$	CHARGE \$	Volume	RATE \$	CHARGE \$	\$	%	% of Total Bill
Monthly Service Charge			\$ 0.36			\$ 0.41	\$ 0.05	13.89%	2.47%
Distribution (kWh)	70	\$ -	\$ -	70	\$ -	\$ -	\$ -	0.00%	0.00%
Distribution (kW)	2	\$ 2.7462	\$ 5.49	2	\$ 3.1067	\$ 6.21	\$ 0.72	13.13%	37.42%
Regulatory Assets (kWh)	70	\$ -	\$ -	70	\$ -	\$ -	\$ -	0.00%	0.00%
Regulatory Assets (kW)	2	\$ 0.0143	\$ 0.03	2	\$ 0.2822	\$ 0.56	\$ (0.59)	2073.43%	-3.40%
Sub-Total			\$ 5.88			\$ 6.06	\$ 0.18	3.03%	36.49%
Other Charges (kWh)	73	\$ 0.0132	\$ 0.96	73	\$ 0.0132	\$ 0.96	\$ -	0.00%	5.76%
Other Charges (kW)	2	\$ 2.7731	\$ 5.75	2	\$ 2.7731	\$ 5.75	\$ -	0.00%	34.60%
Cost of Power Commodity (kWh)	73	\$ 0.0530	\$ 3.84	73	\$ 0.0530	\$ 3.84	\$ -	0.00%	23.15%

Cost of Power Commodity (kWh)	0	\$ 0.0620	\$ -	0	\$ 0.0620	\$ -	\$ -	0.00%	0.00%
Total Bill before Taxes			\$ 16.43			\$ 16.61	\$ 0.18	1.08%	100%
GST (2007 - 6%, 2008 - 6%)			\$ 0.99			\$ 1.00	\$ 0.01	1.08%	
Total Bill after Taxes			\$ 17.41			\$ 17.60	\$ 0.19	1.08%	

Board Staff Interrogatories

Index of Attachments

1. #5 OEB System Capacity Report 2008.pdf
2. #12a OEB.pdf
3. #12c OEB 2006.pdf
4. #12c OEB 2007.pdf
5. #12c OEB 2008.pdf
6. #21 OEB.pdf
7. #28 OEB Valuation of Early Retirement Benefit Plan.pdf
8. #28 OEB Valuation of Life Insurance program.pdf
9. #39 OEB 2006 Tax Year Filings.pdf
10. #39 OEB 2006 Tax Year Filings T2 and NOA.pdf
11. #41 OEB.pdf
12. #44 OEB.pdf
13. #45a OEB.pdf
14. #45b OEB 2008.pdf
15. #45b OEB.pdf
16. #47 OEB.pdf
17. #49 OEB CDM Programs Duration.pdf
18. #49 OEB LRAM SSM_Net of FreeRiders.pdf
19. #49 OEB LRAM SSM_No Smart Meters.pdf
20. #49 OEB water heater 3rd Tranche Totals.pdf
21. #49 OEB water heater.pdf
22. #56 OEB.pdf
23. #59 OEB 2007 July Financial Markets Monthly.pdf

Board#5



System Capacity Report

2008

SYSTEM PLANNING DEPARTMENT

Version 2.0
October 5, 2007

DOCUMENT ACCEPTANCE and RELEASE NOTICE

This is version 2.0 of the System Capacity Report 2008.

The System Capacity Report is a managed document. For identification of amendments each page contains a release number and a page number. Changes will only be issued as a complete replacement document. Recipients should remove superseded versions from circulation. This document is authorised for release once all signatures have been obtained.

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1. Executive Summary

The Enersource Hydro Mississauga (EHM) System Capacity Report provides a discussion of EHM's anticipated capital developments for the year 2008. The projects that are recommended in this report are related to the reinforcement of a number of areas in the City of Mississauga.

Significant growth has occurred in a number of new housing, industrial and commercial service developments over the last three years. Extensive industrial development is continuing to occur within the North 27.6kV system and this trend is expected to continue over the next three to five years. A major water and waste water treatment plant (26MW) is expected to be fully operational by 2008 and will be fed by the South 27.6kV system. The 44kV system continues to serve predominantly residential and commercial loads and will be further stressed by significant residential loads that are planned and under construction in the western and central portion of the city over the next 2 to 3 years. It is projected that an additional 30MW will be added to the EHM grid in these areas in the next two years. It is clear that EHM's system will have to be expanded in the medium term, to effectively and reliably serve its customers.

The year to-date system peak for 2006 was 1610 MW on August 1st 2006. This system peak, has surpassed our previous system peak record of 1570 MW set back in July 2005, an increase of 2.55%. The Enersource Hydro Mississauga system peak is almost entirely weather driven, and the summer of 2006 marked some of the hottest stretches of days in recent history.

The summer of 2005 overall was much hotter overall than the summer of 2006; this was seen with improved reliability numbers for 2006 compared to 2005. EHM customers experienced an average of 27.2 minutes of power interruption for 2006; which is a decrease of 4.5 minutes (14.2%) from 2005.

2. Introduction

Electrical power in the City of Mississauga originates from 10 Hydro One Transformer Stations (TS). The power is transformed at these TS's from 230 kV down for municipal use to subtransmission voltages of 44 kV and 27.6 kV and to primary distribution voltage of 16.0/27.6 kV. The subtransmission voltages of 44 kV and 27.6 kV are further transformed at the Municipal Substations (MS) owned by Enersource Hydro Mississauga, to primary distribution voltages of 8.0/13.8 kV and 2.4/4.16 kV.

The prime study area (see Figure 2A) identified in the report is broken down into six study regions:

- Meadowvale 44/13.8
- Erindale 44/13.8
- Tomken 44/13.8
- Bramalea-Woodbridge 44/13.8
- North 27.6
- South 27.6/4.16

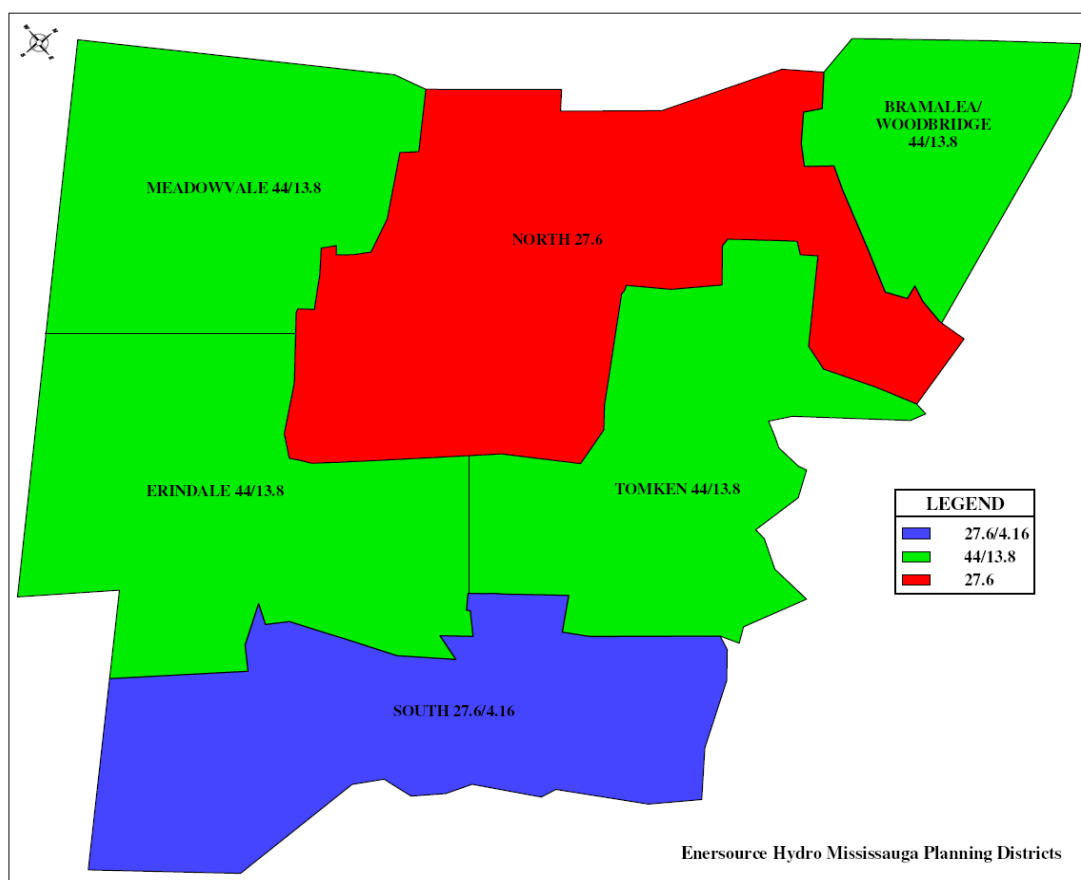


Figure 2A

3. Definition of EHM's Facilities

3.1. Subtransmission Facilities

The subtransmission system consists of power lines that take electrical energy from the transformer stations and delivers it directly to larger customers, or to substations where it is transformed for delivery onto the EHM distribution system. EHM's subtransmission system is comprised of the following:

3.1.1. 44 kV Subtransmission

- Delivery points include Meadowvale TS, Erindale TS, Tomken TS, Bramalea TS and Woodbridge TS.
- 47 operational supply feeders with a total capacity of 1645 MVA.
- 2 possible feeders from Meadowvale (requires bus extension) with a capacity potential of 70MVA.
- 2 express feeders are for export of generation (Trans Alta at Bramalea TS).
- 33 industrial/ commercial customers directly connected with 80 customer owned power transformers.
- 1405 km of 44kV power lines.

3.1.2. 27.6 kV Subtransmission

- Delivery points include Cooksville TS, Lorne Park TS and Oakville TS.
- 26 operational supply feeders with a total capacity of 572 MVA.
- 767 km of 27.6kV power lines.
- 285 customers directly connected (269 industrial/ commercial & 16 residential) with 163 customer owned power transformers.
- 2 express feeders for St. Lawrence Cement
- 2 express feeders for Petro Canada

3.2. Distribution Facilities

The distribution system delivers electrical energy from EHM's substations to the majority of EHM's customers. The EHM distribution system consists of the following:

3.2.1. 16.0/27.6 kV Distribution

- Delivery points are Erindale TS, Bramalea TS, Richview TS and Cardiff TS.
- 32 operational supply feeders with a total capacity of 704 MVA.
- 40,063 customers connected (4,389 industrial/ commercial & 35,674 residential).
- 2778 km of 16.0/27.6 kV power lines.
- 5,953 transformers connected (164 of these are customer owned and the rest EHM).

3.2.2. 8.0/13.8 kV Distribution

- 40 municipal stations comprised of 62 step-down transformers rated 13.8/44 kV.
- 193 operational feeders with a total capacity of 1544 MVA.
- 115,742 customers connected (13,974 industrial/ commercial & 101,768 residential).
- 5,401 km of 8.0/ 13.8kV power lines.
- 15,675 transformers connected.

3.2.3. 2.4/4.16 kV Distribution

- 26 municipal substations comprised of 34 step-down transformers rated 4.16/27.6 kV.
- 103 operational feeders with a total capacity of 247 MVA.
- 28,248 customers connected (2,159 industrial/ commercial & 26,089 residential).
- 1,135 km of 2.4/4.16 kV power lines.
- 3,822 transformers connected.

4. Major Drivers for Facilities Requirement

Additions to the EHM system are normally required because of an expected violation of EHM's performance criteria. Violation of system adequacy, in particular the ability to maintain satisfactory power capacity and voltage levels, are the performance criteria that most often drives requirements for new facilities. EHM checks for violations of its performance criteria. Violations of the performance criteria predicted by the models usually results from forecast increases in power flow over the subtransmission or distribution facilities. Also, aging infrastructure (Reliability) is another factor, which is unrelated to increased power transfers, but may result in a requirement for new or upgrade of facilities.

The major drivers contributing to the need for new or upgrade of facilities include:

- Demand Forecast
- Connection of future new large customers
- Load Duration Curves
- Reliability Performance

4.1. EHM Long Term Demand Forecast

Peak demand has averaged an annual compounded growth of 4.62% over the 2000 to 2006 time frame. Demand growth is a function of the level of weather factors, economic activity, the rate of population growth and the increase in the number of housing units. The City of Mississauga economy has expanded consistently since the year 2000, with the population growing by 40,000 people, also nearly 55,000 new jobs were added and more than 20,000 housing units built.

The forecasting system adapted uses econometric equations to estimate the relationships between peak demand and a number of analytical factors or drivers. The drivers that the system includes are weather effects, economic data, calendar variables, and demand response programs. Using regression techniques, the model estimates the relationship between these drivers and peak demand.

For the purpose of this analysis the weather is not forecasted but instead two scenarios are considered. Normal weather and extreme weather are used to forecast peak demand. The normal weather is the average temperature values of a 35-year history (1972-2006). For the Extreme weather scenario, the historical data used was from the year 2002 which was ranked as one of the highest extreme weather years in history.

Normal weather forecasted (see Table 4A) results for peak demand show an average annual growth rate of 0.5%. This low growth rate indicates the effect of normal temperatures and the eventual maturing of the City of Mississauga in the next 25 years. As the City of Mississauga makes the transition from a fast growing municipality to a mature urban community, the rate of growth of peak demand will decline steadily over the forecast period.

Forecasted Annual Peak Demand (MW)								
2007	2008	2009	2010	2011	2016	2021	2026	2031
1512	1531	1549	1567	1582	1631	1660	1681	1699
-6.09 %	1.26 %	1.18 %	1.16 %	0.96 %	3.10 %	1.78 %	1.27 %	1.07 %

Table 4A – Forecasted Annual Peak Demand (Normal Weather)

For system expansion process, the load forecast results using the extreme weather scenario would be used as the basis to develop strategies to expand the EHM distribution network at the least cost. The reason being is that peak demand occurs over a short time period (hours) and statistically, the likelihood of short extreme weather conditions occurring during the year is high. Table 4B shows the 25 year forecasted annual peak demand for extreme weather temperatures.

Forecasted Annual Peak Demand (MW)								
2007	2008	2009	2010	2011	2016	2021	2026	2031
1635	1666	1685	1703	1717	1766	1795	1816	1834
1.55 %	1.90 %	1.14 %	1.07 %	0.82 %	2.85 %	1.64 %	1.17 %	0.99 %

Table 4B – Forecasted Annual Peak Demand (Extreme Weather)

In summary, the City of Mississauga in the next 5-10 years will have their availability of land supply evaporate. However, modest growth will be maintained as re-development in the City will continue with high density housing being the major economic factor that drives growth in peak demand. The overall load forecast clearly shows the steady decline in load growth for the next 25 years.

Refer to Supporting Document A – EHM Long Term Demand Forecast 2007-2031 for detailed information on EHM demand forecast.

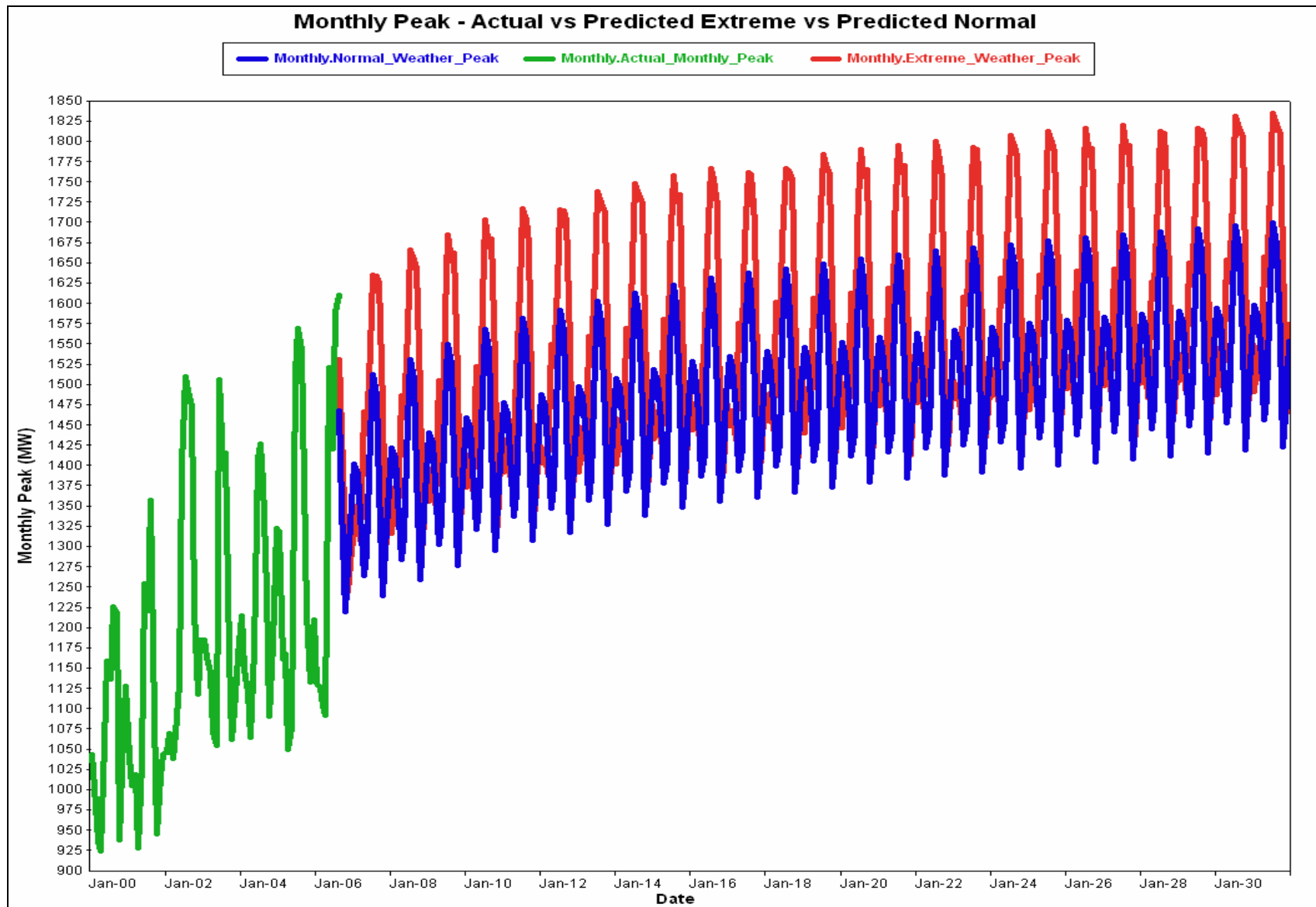


Figure 4A –Monthly Peak 2000-2031: Actual vs Extreme Forecast vs Normal Forecast

4.2. Connection of New Major Load

Significant growth has occurred in a number of new housing, industrial and commercial service developments over the last three years. Extensive industrial development is continuing to occur within the North 27.6kV system and this trend is expected to continue over the next three to five years. A major water and waste water treatment plant (26MW) is expected to be fully operational by 2008 and will be fed by the South 27.6kV system. The 44kV system continues to serve predominantly residential and commercial loads and will be further stressed by significant residential loads that are planned and under construction in the western and central portion of the city over the next 2 to 3 years. It is projected that an additional 30MW will be added to the EHM grid in these areas in the next two years. It is clear that EHM's system will have to be expanded in the medium term, to effectively and reliably serve its customers.

4.3. Load Duration Curves

Load duration curves were developed (see supporting document named "Load Duration Curves" dated August 2006), for 368 feeders and 103 station transformers (monitored by SCADA) for the year or 365 days x 24 hours = 8760 hours which is the x- axis. The feeders should not exceed 1.00 per unit at any given time because this indicates that the feeders have run beyond their operating specifications.

Example:

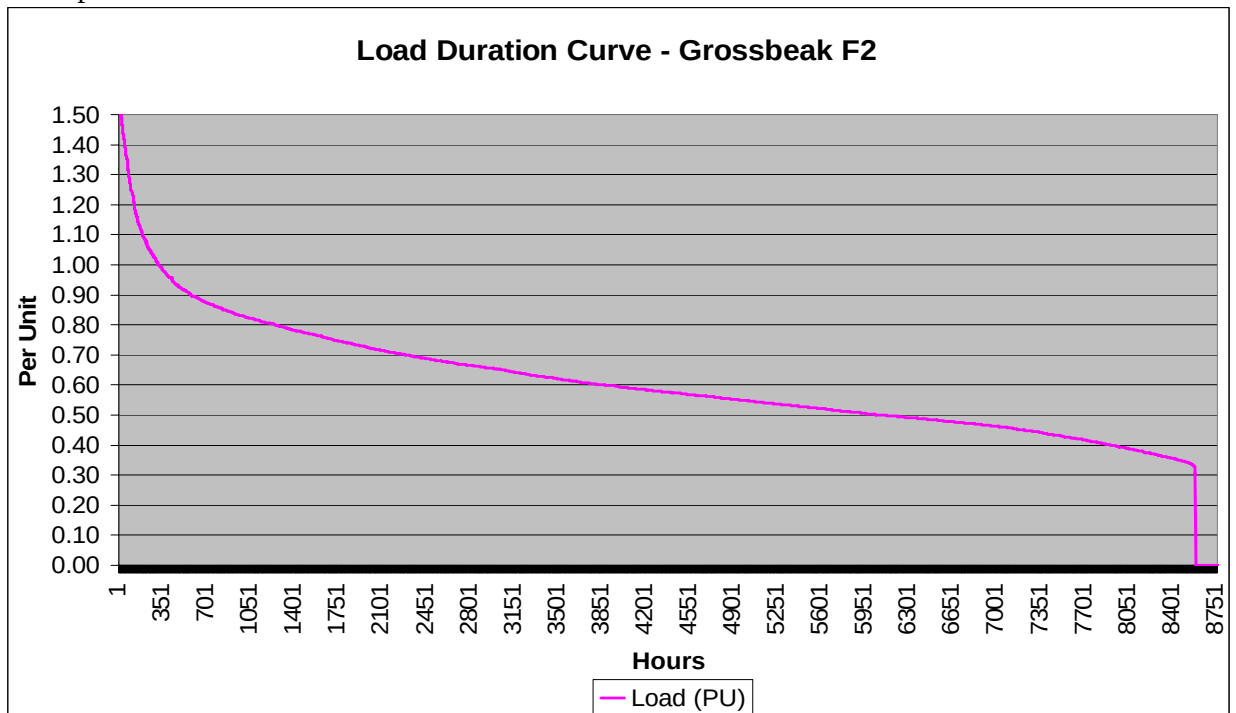


Figure 4B

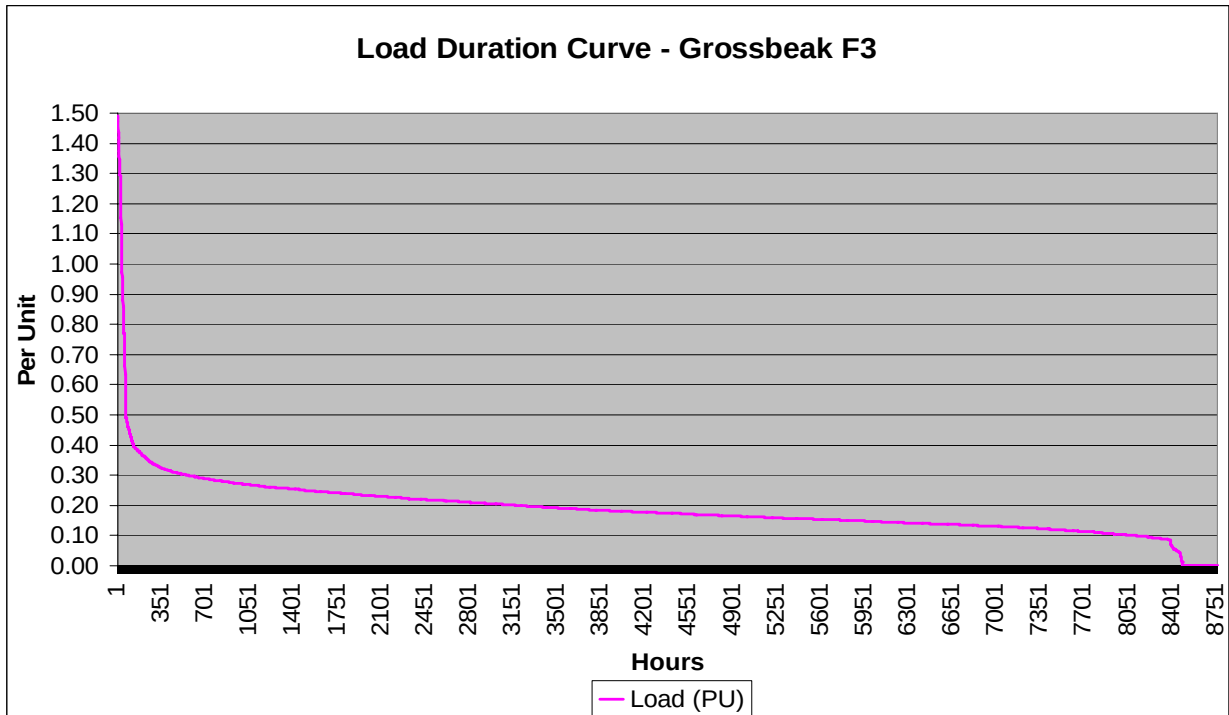


Figure 4C

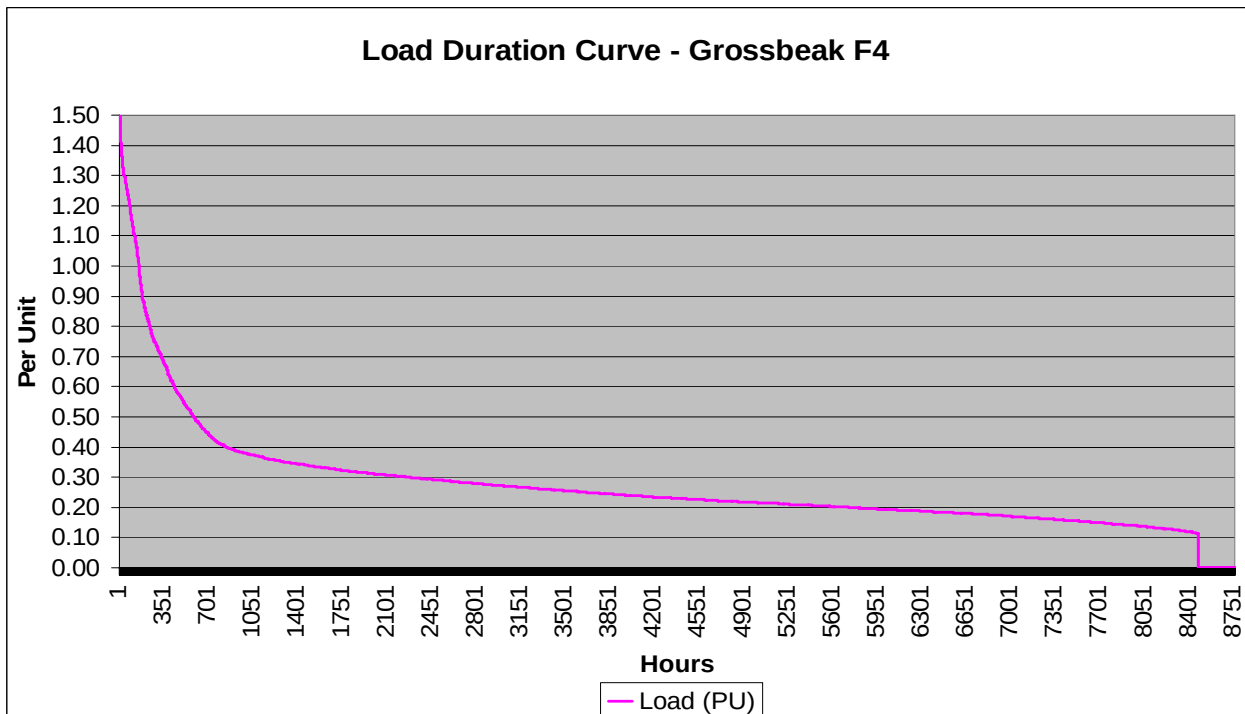


Figure 4D

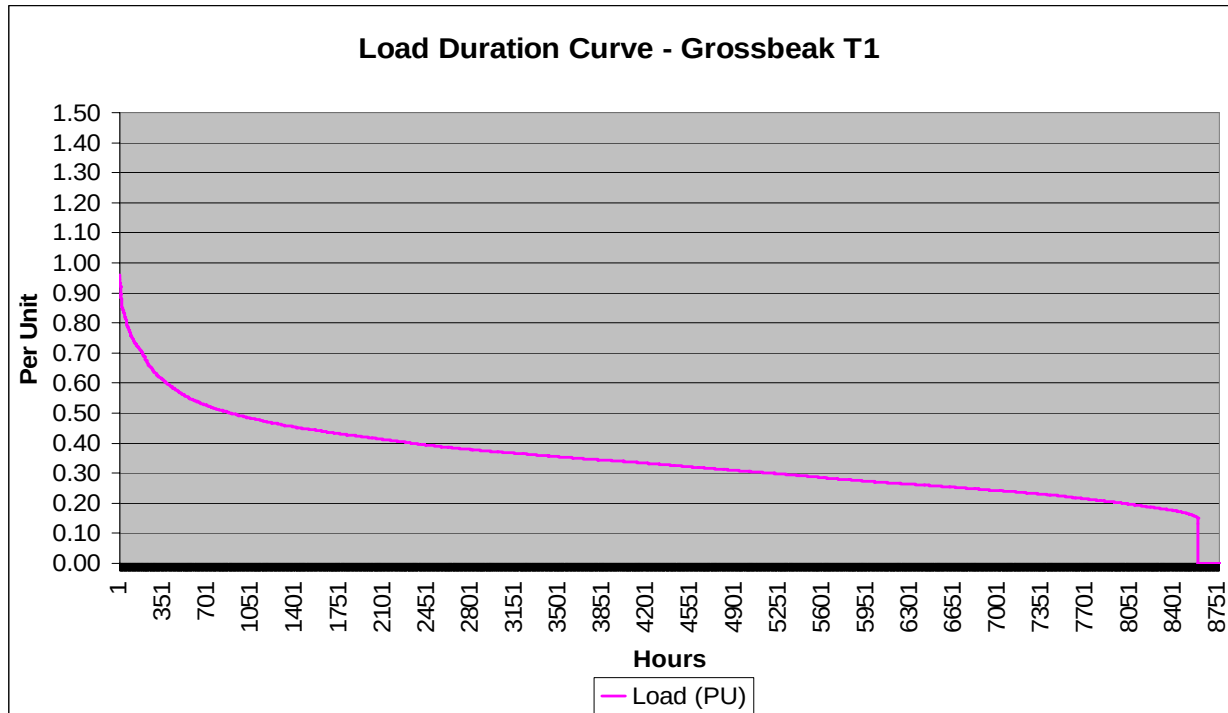


Figure 4E

The load duration curves will be used to identify prolonged or abnormal loading conditions for the feeders and transformers at the stations. This in combination with the reliability data discussed in section 4.5 of this document will be used to identify areas on the EHM system that require immediate attention.

Ideally the feeder curves should not exceed 1.00 per unit. When the curves exceed 1.00 per unit this indicates that the feeders for that time period are being overloaded and are exceeding the cable ampacity ratings. The curves shown in Figures 4B to 4E for Grossbeak MS indicate that several of the feeders often exceed their cable ratings by as much as 150% or 1.50 per unit. This type of prolonged loading can lead to early failure of the cables. It can also be seen that during coincident peak the transformer T1 is already close to the 100% maximum rating (33MVA). With known data that the area which Grossbeak MS serves is experiencing further growth it has been recommended for projects in 2007 that a second 20/33 MVA transformer be added to Grossbeak MS.

4.4. Reliability Performance

System reliability for 2006 marked a significant improvement from 2005 in terms of average customer minutes lost per customer. This is mainly due to the fact that the heat wave of 2006 was limited to several days as compared to the sustained stress on the

system during the heat wave of 2005. Our customers experienced an average of 27.2 minutes of power interruption for 2006; this is a decrease of 4.5 minutes (14.5%) from 2005 (refer to Table 4C).

TOTAL INTERRUPTIONS					
	2006	2005	2004	2003	2002
INTERRUPTIONS	451	484	430	432	496
CUSTOMERS AFFECTED	132,000	166,000	109,000	130,000	108,000
CUSTOMER MINUTES	4,892,000	5,637,000	3,875,000	4,017,000	3,925,000
SAIDI (Minutes)	27.2	31.7	22.1	23.4	23.6
CAIDI (Minutes)	37.1	34.2	35.5	30.8	36.5
SAIFI	0.73	0.93	0.62	0.76	0.65
SAIFI (MI)	3.80	3.40	1.6	2.1	2.0

Table 4C

Cable and splice failures are still the main causes of customer outages (please refer to Figure 4F). Enersource Hydro Mississauga's system continues to age and it is clear that cable replacement must be continued. A detailed review of the performance of individual system components was undertaken as part of this report. This included analysis of loading, line losses and reliability of substations and feeders.

To supply the increasing load and maintain the required system efficiency and reliability, a number of system expansion and rebuild projects are proposed for 2008 to 2010.

In addition, the plan recommends continuation of projects such as remote monitoring of the system, automation as well as upgrading to new RTUs and a new frequency band will allow for accurate loading measurement on system components and faster switching for power restoration during outages. This will improve our ability to increase the loading of the power-carrying components of the electrical distribution network and reduce the need of future construction of additional redundancy in the system.

A number of projects relating to system upgrade, including transformer replacement, overhead distribution upgrade and underground distribution upgrade are also included.

Refer to Supporting Document C - EHM 2006 Year End Reliability Report for detailed information on EHM system reliability for year ending 2006.

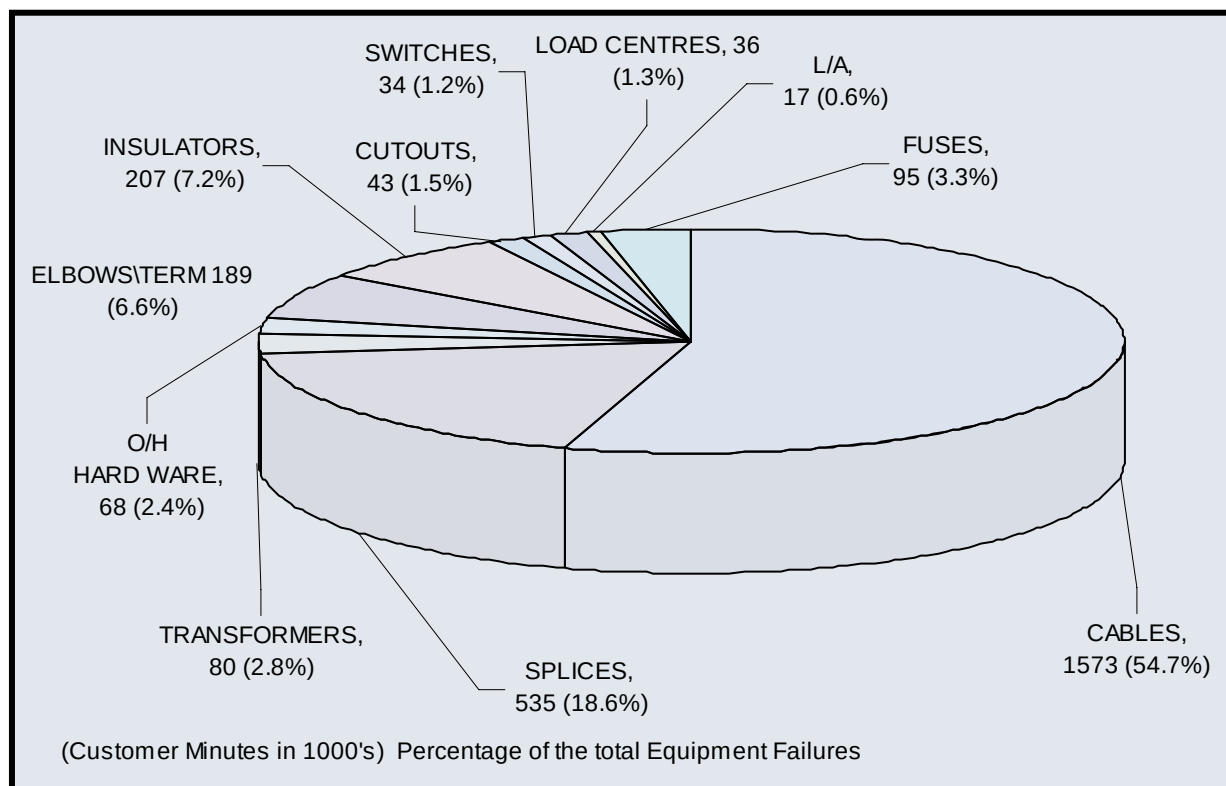


Figure 4F – Equipment Failures

5. Facilities Investment Management

EHM's distribution business aims to continuously improve the capability and performance of the regulated wires assets. This involves facilities investment management processes and practices to ensure that facility related decisions are rational, adequate and economically viable. These decisions are used to help develop logical and prioritized projects for the addition, upgrading, operation and maintenance of EHM facilities.

5.1. Methods of Analyzing Facilities Investment

Facilities and their components are subject to deterioration that will eventually impede their ability to function as originally designed. Facility deterioration depends on factors such as geographic location, utilization, age, weather and maintenance practices. The deterioration process typically manifests itself by a decline in equipment performance reliability, increased environmental risks, and an increase in potential safety hazards to both the public and employees. Ultimately, facilities deteriorate to the point that they are no longer able to perform their function in a cost-effective manner, at which point replacement becomes necessary rather than continue to repair or maintain.

The following are methods, processes and practices used to help analyze EHM facilities investments:

5.1.1. *System Performance*

A detailed review of the performance of individual system components was undertaken. This included analysis of loading, line loss and reliability of the subtransmission feeders, substation transformers and primary feeders.

In addition, a district planning load forecast, based on site plan approvals, building permits, subdivision construction and commercial/industrial service applications, were developed.

For each of the feeders, the following items were used or computed:

- Operator monitoring and experience (daily operator report)
- Reliability performance based on indices which measure the average duration and frequency of outages, were calculated between July 2005 and July 2006.

Analysis of these feeders was performed and methods to overcome the exposure were identified. These methods included measuring the extent of feeder loading, reviewing and expanding maintenance programs and finally the need for new system capital projects.

5.1.2. *Cost Benefit Analysis*

The benefits identified include:

- Additional MW capacity
- Savings to the community due to savings in Customer-minutes and Effective MW minutes of outages
- Projected revenue due to the ability to serve new and existing customers by expanding the network

5.1.3. *Facilities Life Cycle Planning*

The strategy that EHM uses to help manage facilities investments is the Facilities Life Cycle planning approach, see Figure 5A, which aims at optimizing performance and cost over the service life of facilities.

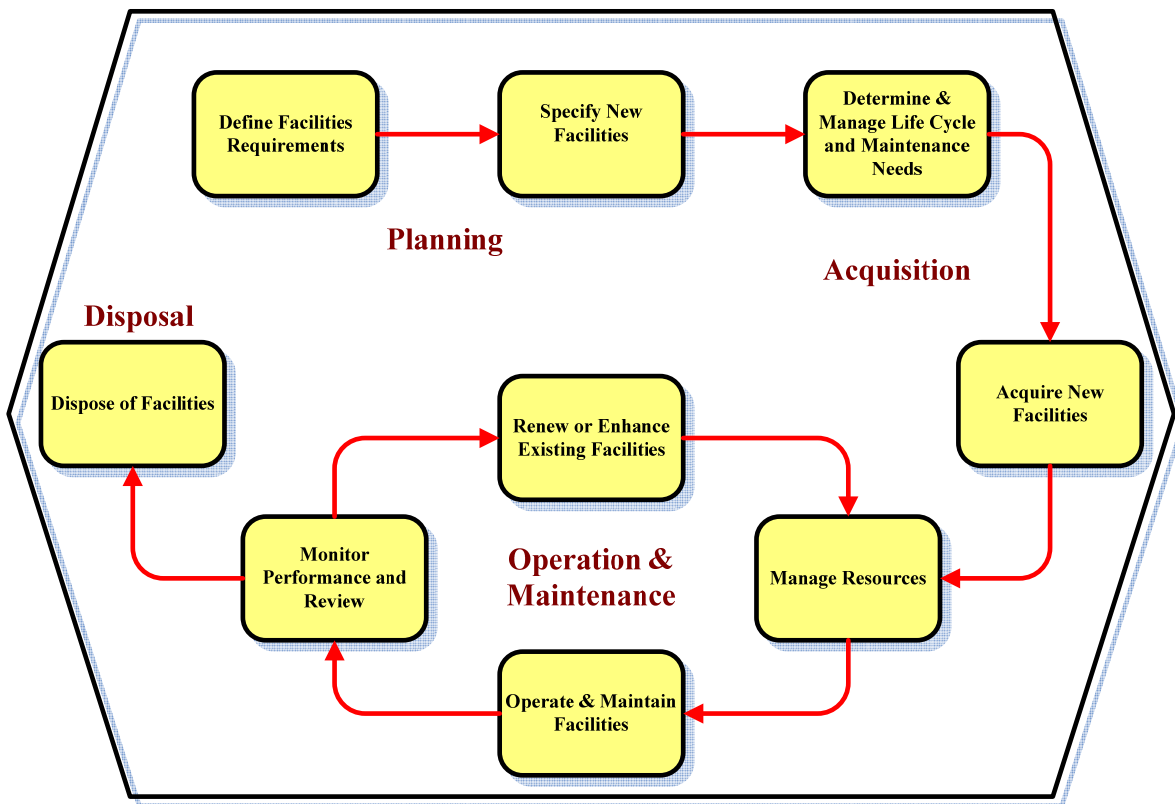


Figure 5A – Facilities Life Cycle Planning

5.1.4. Reliability Measures

The cost of outages to the community is calculated based on the results developed from customer surveys, analytic methods, and actual interruption or case study methods. The results are shown in the following table:

Interruption Cost Models*		
	Duration of Outage	Average Cost \$/kW
Residential Model 1	60 minutes	1.77
Residential Model 2	4 hours	7.08
Commercial Model 1	1 minute	0.47
Commercial Model 2	20 minutes	2.80
Commercial Model 3	8 hours	113.10
Industrial Model 1	1 minute	1.30
Industrial Model 2	20 minutes	4.18
Industrial Model 3	8 hours	42.0

*Based on Surveys and studies as reported to EDA, EPRI and US Department of Energy.

Table 5A

Based on the above values, the savings to the community is conservatively estimated at \$5 per customer-minute of reduction in the power outage.

5.1.5. Risk Assessment & Project Prioritization

The lists of detailed projects that are developed are consistent with the major drivers for facilities discussed in Section 4 of this report. Each specific project is evaluated against certain business values; see Table 5B, to identify associated risks of not conducting the work. Risk assessment is conducted on projects to help develop solutions to mitigate these risks. For each projects a prioritization index (cost versus benefit) is developed and all projects are then prioritized.

Business Value	Key Success Factor	Key Performance Indicator	Weighting
Customer	Improve overall customer satisfaction	Customer satisfaction survey	25 %
Health & Safety	Keep our people, service providers and the public safe	- Employee Safety - Service Provider safety - Public Safety	25 %
Legal/ Regulatory & Environmental Compliance	Meet all compliance Standards	- Regulatory SQI Index - Legal Violations - License conditions	25 %
Reliability & Long Term Sustainability	Improve long term reliability of the Subtransmission and distribution systems	- Unsupplied power - SAIDI - Worst served customers	25 %

Table 5B

The prioritization process converts the business values and key performance indicators in Table 5B into investment criteria and guidelines that are used for managing risk and facilitating trade-offs between facilities investments.

5.2. Facilities Investment Categories & Budgets

In organizing and planning projects, EHM has five main facilities investment categories for projects; System Capacity – Growth Driven Investment; System Maintenance – Reliability Driven Investment; System Expansion & Upgrades – Customer Driven Investment; Non-System Requirements – Regulatory Driven Investment; and Non-System Requirements – Internally Driven Investment. Each of these categories can have a Capital and/or OM&A component.

EHM’s capital programs, historical and proposed budget levels are described below:

5.2.1. System Capacity – Growth Driven Investment

The capital projects for System Capacity – Growth Driven Investments are to ensure that EHM’s capability to provide a secure and reliable supply of electrical energy in response to cumulative system wide load growth demands. Growth is predicted through the combined use of load-forecast models, historical growth patterns, and specific load measurements taken at times of heavy loading during the summer.

Projects for the System Capacity – Growth Driven Investments are designed to increase the capability of existing EHM lines and substations, or to construct new EHM lines and substations in response to system growth forecasts.

The proposed funding of capital projects for System Capacity – Growth Driven Investments and their spending levels for the bridge and historic years are provided in Table 5C below:

(\$ Millions)

Description	Historic				Bridge	Forecast		
	2003	2004	2005	2006	2007	2008	2009	2010
Subtransmission/Distribution Lines Construction	3.86	5.16	5.74	4.83	5.85	5.85		
Substation Construction	2.63	2.73	2.84	3.31	2.88	3.43		
Total	6.50	7.89	8.58	8.14	8.73	9.28		

Table 5C- Capital Budget: System Capacity – Growth Driven Investments

5.2.2. **System Maintenance – Reliability Driven Investment**

System Maintenance – Reliability Driven Investments are defined as projects required for maintaining the existing infrastructure and facilities at their required performance level.

The capital component of the System Maintenance – Reliability Driven Investment projects deal with replacement of assets at end of life, i.e. transformer replacements, subdivision rebuilds and pole replacements. The OM&A component of the sustainment work addresses preventative and breakdown (corrective) maintenance within the useful life-span of the equipment, i.e. underground distribution maintenance, overhead distribution upgrades and refurbish/upgrade data acquisition systems, including automatic system controls, which monitor and control the operation of the EHM system.

The proposed funding of capital projects for System Maintenance – Reliability Driven Investments and their spending levels for the bridge and historic years are provided in Table 5D below:

(\$ Millions)

Description	Historic				Bridge	Forecast		
	2003	2004	2005	2006	2007	2008	2009	2010
Subdivision Rebuilds	2.00	1.75	4.12	4.28	5.95	6.10		
Overhead Distribution Upgrades	3.48	2.56	1.71	2.99	2.53	2.60		
Underground Distribution Maintenance	2.61	2.26	1.74	2.30	2.13	2.20		
Transformer Replacement	0.70	0.73	0.60	0.89	0.60	0.65		
P&C and SCADA Upgrades	1.33	0.78	1.19	1.55	1.37	1.40		
Total	10.11	8.07	9.36	12.00	12.57	12.95		

Table 5D - Capital Budget: System Maintenance – Reliability Driven Investments

5.2.3. **System Expansion & Upgrades – Customer Driven Investment**

System Expansion & Upgrades – Customer Driven Investments are defined as projects required to connect new customers or to modify customers' present service. Projects of this nature are not discretionary, but mandatory, and include work such as new residential/commercial/industrial services, city or region road relocation projects and new/upgrade metering equipment. The proposed funding of capital projects for System Expansion & Upgrades – Customer Driven Investments and their spending levels for the bridge and historic years are provided in Table 5E below:

(\$ Millions)

Description	Historic				Bridge	Forecast		
	2003	2004	2005	2006	2007	2008	2009	2010
New Industrial/Commercial Customer Services	3.50	6.63	6.09	6.91	4.00	4.20		
New Subdivisions	-	-	-	-	2.50	2.58		
Road Projects	0.25	0.55	0.92	0.51	0.75	0.75		
Metering Equipment	0.75	1.24	1.07	1.11	0.84	0.89		
Total	4.50	8.42	8.08	8.52	8.09	8.42		

Table 5E - Capital Budget: System Expansion & Upgrades – Customer Driven Investments

5.2.4. Non-System Requirements – Regulatory Driven Investment

Non-System Requirements – Regulatory Driven Investments are defined as projects which are mandated by electricity regulations. Projects of this nature include wholesale metering upgrades per IESO market rules and OEB sponsored initiatives such as smart metering and conservation/demand response programs. The proposed funding of capital projects for Non-System Requirements – Regulatory Driven Investments and their spending levels for the bridge and historic years are provided in Table 5F below:

(\$ Millions)

Description	Historic				Bridge	Forecast		
	2003	2004	2005	2006	2007	2008	2009	2010
Conservation & Demand Response	-	-	1.15	1.88	0.30	-		
Wholesale Metering	-	-	0.18	0.15	0.28	0.15		
Smart Metering	-	-	-	0.21	9.23	0.98		
Total	-	-	1.33	2.24	9.81			

Table 5F - Capital Budget: Non-System Requirements – Regulatory Driven Investments

5.2.5. Non-System Requirements – Internally Driven Investment

Non-System Requirements – Internally Driven Investments are defined as projects required to enhance, refurbish and replace computer management systems, major tools, building facilities, fleet, information systems and engineering & asset systems. The proposed funding of capital projects for Non-System Requirements – Internally Driven Investments and their spending levels for the bridge and historic years are provided in Table 5G below:

(\$ Millions)

Description	Historic				Bridge	Forecast		
	2003	2004	2005	2006	2007	2008	2009	2010
CIS	-	-	-	-	4.00	6.54		
Rolling Stock	0.08	2.36	1.82	1.62	1.86	1.86		
Major Tools	0.11	0.15	0.20	0.14	0.15	0.15		
Information Technology	1.89	1.32	1.01	1.04	1.09	.72		
Engineering & Asset Systems	1.39	0.66	0.48	2.04	2.40	1.55		
Grounds & Buildings	0.26	1.06	1.60	0.99	2.11	4.65		
Total	3.73	5.54	5.11	5.83	11.60	15.47		

Table 5G - Capital Budget: Non-System Requirements – Internally Driven Investments

6. Recommendations

SUMMARY

Enersource Hydro Mississauga has prepared the System Capacity Report for 2008. A copy of this report is included in this agenda.

The report indicates which additional system capital projects are required to maintain system reliability at an acceptable level and to accommodate increased load on the system.

RECOMMENDATIONS (Resolution)

See Resolution attached.

7. References & Supporting Documents

- 1. A – EHM Load Term Demand Forecast 2007-2031**
- 2. B – EHM Load Duration Curves**
- 3. C – EHM 2006 Year End Reliability Report**
- 4. E – EHM Project Business Cases 2008**

Board #12 a.

Enersource Hydro Mississauga Inc.
 EB-2007-0706
 2008 Electricity Distribution Rates Application
 Filed: November 12, 2007
 Exhibit J
 Schedule 1
 Tab 12

Accumulated Depreciation - Summary Breakdown by Asset Account

Uniform System of Accounts	Description	2008 Test Year	2007 Bridge Year	2006 Historic Actual
1808	BUILDINGS	(5,187,055)	(4,896,803)	(4,608,817)
1820	MUNICIPAL SUBSTATION EQUIPMENT	(27,665,104)	(26,548,809)	(25,324,078)
1980	SUPERVISORY CONTROL EQUIPMENT	(6,858,742)	(6,652,727)	(7,632,970)
1840	UNDERGROUND SUBTRANSMISSION	(890,942)	(866,750)	(842,558)
1830	OVERHEAD PRIMARY	(64,236,144)	(58,650,335)	(52,740,382)
1840	UNDERGROUND PRIMARY	(191,551,420)	(176,232,299)	(161,639,363)
1850	TRANSFORMER	(43,532,120)	(41,751,225)	(39,938,158)
1820	AFUDC-SUBSTATION	(44,223)	(31,135)	(19,141)
1980	AFUDC-SUPERVISORY CONTROL EQUIPMENT	(39,414)	(28,347)	(17,761)
1830	AFUDC-OVERHEAD PRIMARY	(418,202)	(333,524)	(250,144)
1840	AFUDC-UNDERGROUND PRIMARY	(108,736)	(79,254)	(51,088)
1860	METERS	(18,768,022)	(17,610,122)	(16,554,381)
1915	GENERAL OFFICE EQUIPMENT	(2,074,745)	(1,435,706)	(982,449)
1930	ROLLING STOCK	(11,993,834)	(10,745,293)	(10,225,373)
1940	MAJOR TOOLS & INSTRUMENT & GARAGE EQUIPMENT	(701,602)	(662,469)	(590,014)
1920	COMPUTER EQUIPMENT	(3,236,941)	(2,229,531)	(1,829,666)
1925	SOFTWARE	(1,370,484)	(1,466,816)	(1,192,580)
	TOTAL ACCUMULATED DEPRECIATION	(378,677,730)	(350,221,141)	(324,438,918)

Uniformed System of Accounts	DESCRIPTION	Gross fixed Assets		2007	2007	Retirement		Gross Fixed Assets	Deprec	Depreciation	Deprec incurred when items were disposed	50% Depreciation		Total Depreciation
		Beginning Balance December 31, 2006	Capitalizations	Disposals	Assets acquired before 1997	Assets Acquired (subj to 50% depr)	Dec 31, 2007	Term	Beginning Bal	2007 Capitalizations		Assets Acquired (subj to 50% depr)		
1905	LAND	4,071,238					4,071,238		-	-	-	-	-	
1908	BLDGS-BRCK	2,529,165					2,529,165	50	50,583	-	-	-	50,583	
1908	BLDGS-BRCK	10,308,985					10,308,985	60	171,816	-	-	-	171,816	
1908	BLDGS-BRCK	(154,081)					(154,081)	VL	-	-	-	-	-	
1908	BLDGS-OTH	1,876,484					1,876,484	25	75,059	-	-	-	75,059	
1908	BLDGS-OTH	16,160			(16,160)		-	30	539	-	-	-	539	
1908	BLDGS-OTH	(1,207)			1,207		-	VL	-	-	-	-	-	
1920	MUN SUB EQ	55,263,803	2,875,000				58,138,803	30	1,842,127	-	47,917	-	1,890,043	
1920	MUN SUB EQ	9,825,980					9,825,980	35	280,742	-	-	-	280,742	
1920	MUN SUB EQ	(1,021,715)					(1,021,715)	VL	-	-	-	-	-	
1980	SUP CONT	8,788,706	1,370,000		(391,763)		9,766,944	15	585,914	-	45,667	-	631,580	
1980	SUP CONT	4,732,023			(138,090)		4,593,933	25	189,281	-	-	-	189,281	
1980	SUP CONT	5,427					5,427	35	155	-	-	-	155	
1940	UG SUBTRAN	967,691					967,691	40	24,192	-	-	-	24,192	
1940	UG SUBTRAN	56,309					56,309	VL	-	-	-	-	-	
1930	OH PRIMARY	146,995,857	12,406,717				159,402,574	25	5,879,834	-	248,134	-	6,127,969	
1940	UG PRIMARY	373,236,174	19,175,000				392,411,174	25	14,929,447	-	383,500	-	15,312,947	
1940	UG PRIMARY	172,637					172,637	VL	-	-	-	-	-	
1940	UG PRIMARY	26,902,095					26,902,095	35	768,631	-	-	-	768,631	
1940	UG PRIMARY	(726,760)			(1,148,956)		(1,875,716)	VL	-	-	-	-	-	
1950	TRANS-OH	5,541,609					5,541,609	25	221,664	-	-	-	221,664	
1950	TRANS-OH	2,206,186			(163,353)		2,042,833	30	73,540	-	-	-	73,540	
1950	TRANS-OH	162,364			(137,783)		24,581	VL	-	-	-	-	-	
1950	TRANS-UG	50,722,452					50,722,452	25	2,028,898	-	-	-	2,028,898	
1950	TRANS-UG	10,456,049			(944,840)		9,511,210	30	348,535	-	-	-	348,535	
1950	TRANS-UG	(463,737)			360,822		(102,915)	VL	-	-	-	-	-	
1950	TRANS-INV	356,468					356,468	30	11,882	-	-	-	11,882	
1920	AFUDC-Substation	392,638					392,638	30	13,088	-	-	-	13,088	
1980	AFUDC-Supvcon	166,011					166,011	15	19,483	-	-	-	19,483	
1930	AFUDC-OH Prim	2,116,957					2,116,957	25	84,678	-	-	-	84,678	
1940	AFUDC-UG Prim	737,047					737,047	25	29,482	-	-	-	29,482	
1960	METERS	27,593,766	2,726,241				30,320,007	25	1,103,751	-	69,390	-	1,173,141	
1960	METERS (DISPOSALS)			(90,139)			(90,139)	25	(8,655)	-	-	-	(8,655)	
1960	METERS	7,618,915			(341,410)		7,277,505	35	217,683	-	-	-	217,683	
1960	METERS	(1,654,466)			50,222		(1,604,244)	VL	-	-	-	-	-	
1915	GEN OFF EQ	4,308,634	2,110,000			(6,650)	6,411,985	10	430,863	-	105,500	(332)	536,031	
1930	ROLL STOCK	8,482,082	1,295,000			(2,383,632)	7,393,449	8	1,060,260	-	80,938	(148,977)	992,221	
1930	ROLL STOCK	1,463		(1,463)			-	8	-	15	-	-	15	
1930	ROLL STOCK	3,834,618				2,383,632	6,218,250	RET	-	-	-	-	-	
1930	ROLL STOCK	210,364		(210,364)			-	RET	-	-	-	-	-	
1930	ROLL STOCK	1,641,721	260,000			(159,571)	1,742,149	5	328,344	-	26,000	(15,957)	338,387	
1930	ROLL STOCK	464,118				159,571	623,689	RET	-	-	-	-	-	
1930	ROLL STOCK	298,195		(298,195)			-	RET	-	-	-	-	-	
1930	ROLL STOCK	595		(595)			-	5	-	40	-	-	40	
1930	ROLL STOCK	472,724	306,800				779,524	4	118,181	-	38,350	-	156,531	
1930	ROLL STOCK	40,147					40,147	RET	-	-	-	-	-	
1940	GARAGE EQP	13,176	613,000				626,176	10	1,318	-	30,650	-	31,968	
1940	MAJOR TOOLS & INSTR	1,438,910	150,000			(165,272)	1,423,637	10	143,891	-	7,500	(8,264)	143,127	
1920	COMP EQUIP	4,567,435	2,395,000			(512,882)	6,449,553	5	921,119	-	239,500	(51,288)	1,109,331	
1555	COMP EQUIP-SM						-	5	-	-	-	-	-	
1925	SOFTWARE	2,862,567	1,087,000			(944,543)	3,005,024	2	1,454,918	-	271,750	(236,136)	1,490,532	
1555	SOFTWARE -SM						-	2	-	-	-	-	-	
	SUB-TOTAL	778,433,980	46,769,758	(600,756)	(2,870,104)	(1,629,347)	820,103,530		33,401,245		1,594,795	(460,954)	34,535,141	
1995	CIAC-OVERHEAD PRIMARY	(5,103,700)	(600,000)				(5,703,700)	25	(204,148)		(12,000)	-	(216,148)	
1995	CIAC-UNDERGROUND PRIMARY	(48,410,870)	(3,000,000)				(51,410,870)	25	(1,936,435)		(60,000)	-	(1,996,435)	
1995	CIAC-TRANSFORMERS UG	(7,698,767)	(400,000)				(8,098,767)	25	(307,951)		(8,000)	-	(315,951)	
	SUB-TOTAL	(61,213,337)	(4,000,000)	-	-	-	(65,213,337)		(2,448,533)		(80,000)	-	(2,528,533)	
	SUB-TOTAL (Gross F-A)	717,220,643	42,769,758	(600,756)	(2,870,104)	(1,629,347)	754,890,194	-	30,952,712	-	1,514,795	(460,954)	32,096,607	
	AS AT DEC. 31, 2006													
	GROSS FIXED ASSETS	717,220,643					754,890,194							
2055	CIP	8,463,722					9,182,005							
1995	CIAC BY SUBLEDGER	(342,678)												
2105	ACCUMULATED DEPRECIATION	(335,448,684)					(364,993,597)							
1555	ACCUMULATED DEPRECIATION(SM)													
1995	CIAC AMORTIZATION(STARTING 2000)	9,360,165					11,888,699							
	TOTAL NET FIXED ASSETS	399,253,168					410,967,300							
	LESS: CIP	(8,463,722)					(9,182,005)							
		390,789,446					401,785,295							

2006 Actuals													
Uniformed		Gross fixed Assets	2006	2006	Retirement		Gross Fixed Assets	Deprec	Depreciation		50% Depreciation		
					Assets acquired before 1997	Assets Acquired (subj to 50% depr)					2006	Assets Acquired (subj to 50% depr)	
System of Accounts	DESCRIPTION	Beginning Balance	Capitalizations	Disposals			Dec 31, 2006	Term	Beginning Bal	Deprec incurred before disposal	Capitalizations		
1905	LAND	4,071,238					4,071,238		-		-	-	-
1808	BLDGS-BRCK	2,015,957	513,208				2,529,165	50	40,319		5,132	-	45,451
1808	BLDGS-BRCK	10,308,985					10,308,985	60	171,816		-	-	171,816
1808	BLDGS-BRCK	(154,081)					(154,081)	VL	-		-	-	-
1808	BLDGS-OTH	1,879,547	(3,064)				1,876,484	25	75,182	(61)	-	-	75,121
1808	BLDGS-OTH	16,160					16,160	30	539		-	-	539
1808	BLDGS-OTH	(1,207)					(1,207)	VL	-		-	-	-
1820	MUN SUB EQ	51,957,668	3,306,136				55,263,803	30	1,731,922		55,102	-	1,787,025
1820	MUN SUB EQ	12,352,142			(2,526,161)		9,825,980	35	352,918		-	-	352,918
1820	MUN SUB EQ	(1,686,610)			664,895		(1,021,715)	VL	-		-	-	-
1980	SUP CONT	10,393,639	1,566,603		(3,171,536)		8,788,706	15	692,909		52,220	-	745,129
1980	SUP CONT	4,747,313			(15,290)		4,732,023	25	189,893		-	-	189,893
1980	SUP CONT	5,427					5,427	35	155		-	-	155
1840	UG SUBTRAN	967,691					967,691	40	24,192		-	-	24,192
1840	UG SUBTRAN	56,309					56,309	VL	-		-	-	-
1830	OH PRIMARY	137,601,067	9,394,789				146,995,857	25	5,504,043		187,896	-	5,691,938
1840	UG PRIMARY	358,842,268	14,393,906				373,236,174	25	14,353,691		287,878	-	14,641,569
1840	UG PRIMARY	26,642		(26,642)			977	25	-		-	-	977
1840	UG PRIMARY	172,637					172,637	VL	-		-	-	-
1840	UG PRIMARY	26,902,095					26,902,095	35	768,631		-	-	768,631
1840	UG PRIMARY	422,197			(1,148,956)		(726,760)	VL	-		-	-	-
1850	TRANS-OH	5,541,609					5,541,609	25	221,664		-	-	221,664
1850	TRANS-OH	2,325,811			(119,625)		2,206,186	30	77,527		-	-	77,527
1850	TRANS-OH	343,875			(181,511)		162,364	VL	-		-	-	-
1850	TRANS-UG	50,557,817	164,635				50,722,452	25	2,022,313		3,293	-	2,025,605
1850	TRANS-UG	11,257,344			(801,295)		10,456,049	30	375,245		-	-	375,245
1850	TRANS-UG	(681,014)			217,277		(463,737)	VL	-		-	-	-
1850	TRANS-INV	356,468					356,468	30	11,882		-	-	11,882
1820	AFUDC-Substation	261,374	131,264				392,638	30	8,712		2,188	-	10,900
1980	AFUDC-Supvcon	137,146	28,865				166,011	15	9,143		962	-	10,105
1830	AFUDC-OH Prim	1,987,097	129,860				2,116,957	25	79,484		2,597	-	82,081
1840	AFUDC-UG Prim	605,499	131,549				737,047	25	24,220		2,631	-	26,851
1860	METERS	26,137,541	1,456,225				27,593,766	25	1,045,502		29,125	-	1,074,626
1860	METERS	7,855,371			(236,456)		7,618,915	35	224,439		-	-	224,439
1860	METERS	(1,599,734)			(54,732)		(1,654,466)	VL	-		-	-	-
1915	GEN OFF EQ	3,234,006	1,074,628			-	4,308,634	10	323,401		53,731	-	377,132
1930	ROLL STOCK	7,585,186	961,908	(63,550)			8,483,545	8	941,340	4,732	59,551	-	1,005,623
1930	ROLL STOCK	907,582		(214,915)		(692,667)	-	8	86,583	2,927	-	(43,292)	46,219
1930	ROLL STOCK	4,105,166		(752,851)		692,667	4,044,982	RET	-		-	-	-
1930	ROLL STOCK	1,151,341	498,321	(7,346)			1,642,316	5	228,799	1,347	49,832	-	279,978
1930	ROLL STOCK	121,837			(121,837)		-	5	24,367		-	(12,184)	12,184
1930	ROLL STOCK	967,629		(327,154)	121,837		762,312	RET	-		-	-	-
1930	ROLL STOCK	366,449	106,275		-		472,724	4	91,612		13,284	-	104,897
1930	ROLL STOCK	42,978		(42,978)	-		-	4	-	4,477	-	-	4,477
1930	ROLL STOCK	82,872		(42,725)	-		40,147	RET	-		-	-	-
1940	GARAGE EQP	13,176					13,176	10	1,318		-	-	1,318
1940	MAJOR TOOLS & INSTR	1,236,487	202,423			-	1,438,910	10	123,649		10,121	-	133,770
1920	COMP EQUIP	3,085,655	1,481,780				4,567,435	5	617,131		148,178	-	765,309
1920	COMP EQUIP	710,133		(710,133)			-	5	-	29,594	-	-	29,594
1925	SOFTWARE	2,226,025	1,918,024			(1,281,482)	2,862,567	2	1,113,013		479,506	(320,370)	1,272,148
	SUB-TOTAL	751,819,812	37,457,335	(2,188,295)	(7,373,391)	(1,281,482)	778,433,980		31,558,531	43,076	1,443,167	(375,846)	32,668,928
	CIAC-OVERHEAD PRIMARY	(4,511,420)	(592,281)				(5,103,700)	25	(180,457)		(11,846)	-	(192,302)
	CIAC-UNDERGROUND PRIMARY	(46,407,418)	(2,003,452)				(48,410,870)	25	(1,856,297)		(40,069)	-	(1,896,366)
	CIAC-TRANSFORMERS UG	(7,544,455)	(154,311)				(7,698,767)	25	(301,778)		(3,086)	-	(304,864)
	SUB-TOTAL	(58,463,293)	(2,750,044)	-	-	-	(61,213,337)		(2,338,532)		(55,001)	-	(2,393,533)
	GRAND TOTAL	693,356,519	34,707,292	(2,188,295)	(7,373,391)	(1,281,482)	717,220,643	-	29,220,000	43,076	1,388,166	(375,846)	30,275,396

	AS AT DEC. 31, 2006			AS AT DEC. 31, 2006		
	GROSS FIXED ASSETS	693,356,519		GROSS FIXED ASSETS	717,220,643	
2055	CIP	7,312,451	2055	CIP	8,463,722	
1995	CIAC BY SUBLEDGER	(158,873)	1995	CIAC BY SUBLEDGER	(342,878)	
2105	ACCUMULATED DEPRECIATION	(313,429,151)	2105	ACCUMULATED DEPRECIATION	(335,448,684)	
1995	CIAC AMORTIZATION(STARTING 2000)	6,966,632	1995	CIAC AMORTIZATION(STARTING 2000)	9,360,165	
	TOTAL NET FIXED ASSETS	394,047,580		TOTAL NET FIXED ASSETS	399,253,168	
	LESS: CIP	(7,312,451)			(8,463,722)	
		386,735,128			390,789,446	
	Average Net Fixed Assets (Rate Base)			Average Accumulated Depreciation		
	Opening Fixed Assets	386,735,128		Opening Accumulated Depreciation	(313,429,151)	
	Closing Fixed Assets	390,789,446		Closing Accumulated Depreciation	(335,448,684)	
		777,524,574			(648,877,834)	
	Average Net Fixed Assets (Rate Base)	388,762,287		Average Accumulated Depreciation	(324,438,917)	

Board #21

ExB Sch3 Tab2 - Appendix A (Updated with Jan'05-Apr'07)

Trading Month	Actual Energy (MWh)	Weather Corrected Energy (MWh)	Weather Correction (MWh)		Actual Peak (MW)	Weather Corrected Peak (MW)	Weather Correction (MW)
Jan-97	591,610	590,006	-1,604		992	991.75	-0.25
Feb-97	523,702	527,801	4,100		962	956.34	-5.66
Mar-97	545,585	542,230	-3,355		922	910.93	-11.07
Apr-97	513,752	508,989	-4,764		893	896.34	3.34
May-97	504,262	507,362	3,100		854	940.13	86.13
Jun-97	558,780	528,907	-29,872		1,211	1,141.18	-69.82
Jul-97	604,731	599,456	-5,275		1,256	1,184.47	-71.53
Aug-97	558,571	575,001	16,430		1,041	1,127.03	86.03
Sep-97	516,623	515,330	-1,293		968	983.7	15.7
Oct-97	530,956	524,094	-6,862		927	959.1	32.1
Nov-97	547,008	538,899	-8,108		976	974.73	-1.27
Dec-97	576,496	581,483	4,987		1,009	1,017.23	8.23
Jan-98	585,118	600,767	15,649		1,005	1,008.88	3.88
Feb-98	523,095	538,760	15,665		964	966	2
Mar-98	570,073	572,179	2,106		948	951.39	3.39
Apr-98	505,489	512,983	7,495		880	917.98	37.98
May-98	537,853	518,021	-19,832		1,084	936.97	-147.03
Jun-98	582,393	552,061	-30,331		1,234	1,038.81	-195.19
Jul-98	629,387	615,393	-13,994		1,283	1,169.64	-113.36
Aug-98	633,247	596,845	-36,402		1,242	1,111.96	-130.04
Sep-98	562,308	534,713	-27,595		1,116	1,001.02	-114.98
Oct-98	534,822	538,805	3,983		917	978.76	61.76
Nov-98	551,434	554,989	3,555		970	976.08	6.08
Dec-98	578,814	592,818	14,004		1,039	1,043.45	4.45
Jan-99	600,424	606,536	6,113		1,042	1,029.05	-12.95
Feb-99	529,880	545,959	16,079		980	999.95	19.95
Mar-99	570,446	579,987	9,541		941	959.91	18.91
Apr-99	512,921	524,160	11,240		890	951.1	61.1
May-99	536,202	529,427	-6,775		1,032	971.83	-60.17
Jun-99	620,353	572,299	-48,054		1,259	1,091.43	-167.57
Jul-99	687,947	619,945	-68,002		1,344	1,129.94	-214.06
Aug-99	611,838	608,828	-3,010		1,163	1,102.77	-60.23
Sep-99	573,254	547,666	-25,588		1,157	999.46	-157.54
Oct-99	547,026	548,861	1,835		926	957.22	31.22
Nov-99	561,078	569,948	8,870		1,008	1,011.63	3.63
Dec-99	619,204	617,121	-2,083		1,088	1,058.42	-29.58
Jan-00	629,285	632,324	3,039		1,074	1,078.52	4.52
Feb-00	583,255	590,826	7,571		1,034	1,036.10	2.1
Mar-00	585,126	602,215	17,089		965	1,002.96	37.96
Apr-00	540,107	539,457	-650		952	974.98	22.98
May-00	572,602	559,734	-12,868		1,129	1,002.28	-126.72
Jun-00	595,751	589,098	-6,653		1,218	1,226.63	8.63
Jul-00	628,485	647,989	19,504		1,186	1,273.56	87.56
Aug-00	652,999	635,220	-17,780		1,300	1,176.54	-123.46

Sep-00	589,437	568,356	-21,081		1,305	1,094.94	-210.06
Oct-00	576,968	576,146	-822		986	1,010.56	24.56
Nov-00	592,190	589,548	-2,642		1,082	1,039.31	-42.69
Dec-00	647,661	626,671	-20,990		1,124	1,098.32	-25.68
Jan-01	649,509	657,965	8,456		1,091	1,115.88	24.88
Feb-01	582,294	586,496	4,201		1,060	1,066.73	6.73
Mar-01	627,174	625,154	-2,020		1,044	1,025.30	-18.7
Apr-01	557,728	560,575	2,847		970	1,001.86	31.86
May-01	584,419	580,656	-3,763		1,105	1,058.03	-46.97
Jun-01	645,564	609,339	-36,225		1,373	1,277.60	-95.4
Jul-01	659,492	662,802	3,309		1,373	1,295.85	-77.15
Aug-01	722,902	659,988	-62,914		1,477	1,231.79	-245.21
Sep-01	602,684	584,047	-18,637		1,189	1,122.78	-66.22
Oct-01	602,304	600,165	-2,138		1,045	1,012.40	-32.6
Nov-01	597,480	611,197	13,717		1,062	1,082.81	20.81
Dec-01	624,215	644,378	20,163		1,090	1,128.32	38.32
Jan-02	654,337	679,473	25,136		1,088	1,148.05	60.05
Feb-02	594,862	607,992	13,130		1,115	1,105.26	-9.74
Mar-02	632,565	638,560	5,995		1,077	1,056.27	-20.73
Apr-02	599,937	590,917	-9,020		1,108	1,044.72	-63.28
May-02	613,199	605,904	-7,295		1,130	1,071.26	-58.74
Jun-02	654,990	627,324	-27,666		1,402	1,297.12	-104.88
Jul-02	781,059	703,735	-77,324		1,509	1,339.59	-169.41
Aug-02	745,061	684,396	-60,665		1,493	1,257.97	-235.03
Sep-02	673,569	611,588	-61,981		1,474	1,143.51	-330.49
Oct-02	632,948	620,559	-12,389		1,221	1,043.85	-177.15
Nov-02	635,185	629,365	-5,820		1,117	1,105.26	-11.74
Dec-02	668,269	668,534	264		1,185	1,153.44	-31.56
Jan-03	704,264	698,462	-5,802		1,185	1,154.47	-30.53
Feb-03	639,371	628,694	-10,677		1,164	1,125.33	-38.67
Mar-03	660,612	660,134	-478		1,143	1,072.71	-70.29
Apr-03	612,394	604,123	-8,271		1,071	1,052.07	-18.93
May-03	611,207	616,952	5,745		1,055	1,100.94	45.94
Jun-03	651,350	638,882	-12,468		1,505	1,296.12	-208.88
Jul-03	721,223	707,202	-14,021		1,400	1,356.95	-43.05
Aug-03	683,386	683,386	0		1,416	1,294.35	-121.65
Sep-03	621,515	612,468	-9,047		1,164	1,144.62	-19.38
Oct-03	622,719	623,829	1,110		1,062	1,094.90	32.9
Nov-03	630,346	635,281	4,935		1,117	1,117.82	0.82
Dec-03	670,992	681,827	10,835		1,165	1,168.85	3.85
Jan-04	714,721	704,065	-10,656		1,215	1,154.92	-60.08
Feb-04	653,440	657,097	3,658		1,149	1,129.70	-19.3
Mar-04	671,008	677,347	6,339		1,120	1,090.95	-29.05
Apr-04	617,241	616,539	-702		1,064	1,062.58	-1.42
May-04	626,305	622,928	-3,377		1,173	1,097.23	-75.77
Jun-04	647,295	652,357	5,061		1,408	1,195.32	-212.68
Jul-04	693,708	711,214	17,507		1,427	1,295.59	-131.41
Aug-04	689,041	693,365	4,324		1,379	1,282.52	-96.48
Sep-04	661,780	642,474	-19,306		1,250	1,165.83	-84.17
Oct-04	632,872	636,362	3,490		1,095	1,093.64	-1.36
Nov-04	642,602	650,927	8,325		1,141	1,127.05	-13.95

Dec-04	690,656	692,021	1,365		1,241	1,195.72	-45.28
Jan-05	721,089	708,305	-12,784		1,226	1,201	-24.18
Feb-05	639,696	635,043	-4,653		1,151	1,159	7.74
Mar-05	686,331	679,773	-6,558		1,139	1,120	-18.22
Apr-05	616,175	616,519	344		1,050	1,086	35.75
May-05	627,752	630,091	2,339		1,081	1,083	1.8
Jun-05	755,352	671,881	-83,471		1,539	1,345	-193.62
Jul-05	793,725	727,505	-66,220		1,570	1,392	-177.8
Aug-05	766,859	715,748	-51,111		1,510	1,347	-163.06
Sep-05	674,409	639,131	-35,278		1,360	1,198	-162.38
Oct-05	646,612	640,827	-5,785		1,197	1,107	-89.71
Nov-05	651,141	653,676	2,535		1,163	1,146	-17.11
Dec-05	698,177	689,635	-8,543		1,216	1,187	-28.89
Jan-06	691,196	711,284	20,088		1,166	1,214	47.77
Feb-06	640,324	640,986	662		1,154	1,177	22.52
Mar-06	684,235	688,284	4,049		1,119	1,130	10.34
Apr-06	601,033	611,704	10,671		1,047	1,096	48.97
May-06	650,016	640,101	-9,916		1,505	1,127	-377.83
Jun-06	696,320	671,914	-24,406		1,415	1,376	-38.93
Jul-06	785,520	734,666	-50,854		1,580	1,422	-157.74
Aug-06	738,477	718,763	-19,714		1,610	1,331	-279.68
Sep-06	629,090	635,322	6,232		1,191	1,204	12.88
Oct-06	643,496	645,952	2,456		1,079	1,095	15.59
Nov-06	649,379	656,538	7,158		1,134	1,144	10.16
Dec-06	671,891	689,818	17,927		1,200	1,205	4.63
Jan-07	710,693	720,267	9,574		1,217	1,268	51.2
Feb-07	669,195	652,353	-16,842		1,235	1,183	-51.4
Mar-07	683,992	688,433	4,441		1,160	1,132	-27.78
Apr-07	630,838	626,800	-4,038		1,093	1,111	18.17

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March 2, 2007

Mr. Don Williamson
Senior Account Manager
The Williamson Group
225 King George Rd
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Re: Enersource Early Retirement Benefit Plan

As requested, I have prepared a valuation as at January 1, 2007 of the early retirement benefit program that Enersource Corporation provides to its employees who retire after age 55 with at least 10 years of service. The benefit package provides benefits until the retiree attains age 65.

A description of these benefits is included in Appendix A. The results shown below represent the employer portion of the cost of the benefit package based on the employer paying 50% of the cost for members who retire with 10 to 15 years of service and 75% of the cost for members who retire with 15 or more years of service.

The employee data for purposes of this valuation was provided by Enersource Corporation as at July 4, 2005. There are no retired or inactive employees included in this data. A summary of the employee data is included as Appendix B.

The actuarial assumptions used are summarized in Appendix C.

The following tables indicate the financial information for the post-retirement non-pension benefits as of January 1, 2007 determined in accordance with CICA 3461.

Accrued Post-Retirement Benefit Cost	
Expected post-retirement benefit obligation	\$3,079,394
Accrued post-retirement benefit obligation (ABO)	\$1,891,801
Unrecognized gain (loss)	\$(176,693)
Unrecognized Transition Obligation	\$1,333,008
Benefits paid in 2006	\$1,474
Expected Average Remaining Service Lifetime	8.50
Net amortization of Transition Obligation	\$166,935
Service cost for benefits earned during year	\$137,892
Interest on ABO	\$78,747
Net periodic post-retirement benefit cost	\$383,574

Net post-retirement benefit expense (2007)	
Service cost for benefits earned during 2007	\$137,900
Interest cost	107,600
Net amortization of Transition Obligation	\$166,900
Net post-retirement benefit expense (2007)	\$411,400

A 1% increase (decrease) in the interest assumption would decrease (increase) the expected post-retirement benefit obligation, the ABO and the service cost by approximately 10%.

The **expected post-retirement benefit obligation** is the present value, as of the valuation date, of the benefits expected to be paid to current employee under the proposed benefit plan.

The **accrued post-retirement benefit obligation** is the present value of the benefits attributed to employee service rendered prior to the valuation date.

The **expected average remaining service lifetime** is the average expected amount of service that current employees will accrue in the future up to their first eligibility for benefits under the plan. To determine the employer's expense for financial statement purposes, the ABO is amortized on a straight line basis over the expected average remaining service lifetime.

The **service cost for benefits earned during the year** is the present value of benefits

attributed to the one year of service following the valuation date.

Because the ABO is amortized on a straight line basis but the ABO reflects a discount for interest, it is necessary to add to the expense **interest on ABO** at the valuation rate of interest.

The **net periodic post-retirement benefit cost** is the sum of the amount of the amortization of the ABO plus the interest on the ABO plus the service cost.

This valuation was based on the employee data provided by Enersource Corporation. I have reviewed the data for reasonableness and internal consistency. In my opinion, the data is sufficient and reliable for the purpose of this valuation.

In my opinion, the assumptions are appropriate for the purpose of this valuation. Emerging experience under the Plans may be different from the assumptions and may result in gains and losses which will be revealed in future valuations.

In my opinion, the methods adopted are in accordance with the requirements of the CICA Handbook. This report has been prepared and my opinions have been given in accordance with generally accepted actuarial practice.

Yours truly,

A handwritten signature in black ink, appearing to read "K. Paul Duxbury". The signature is fluid and cursive, with the first letters of the first and last names being capitalized and prominent.

K. Paul Duxbury

APPENDIX A – PLAN PROVISIONS

The following is a summary of the benefit plans valued in the Report. Complete details are available in the insurance contracts, employee booklets, and plan documents.

Eligibility

All hourly and salaried employees who retire from active service with Enersource Corporation on or after age 55 with at least 10 years of service with Enersource Corporation will be eligible. The spouses and unmarried dependent children under age 21 (age 25 if attending full-time college or university) of such retirees are also eligible.

Employee Contributions

Employees who retire on or after age 55 with 10 but less than 15 years of service will pay 50% of the premiums and employees who retire after age 55 with 15 or more years of service will pay 25% of the premiums.

Summary of Benefit Coverages

- Dependent Definition 21/25
- Health Care:
 - Deductible: Nil
 - Coinsurance
 - Drugs 80%
 - All Other Benefits 100%
 - Out of pocket maximum \$200 per person, thereafter 100%
 - Hospital No semi-private or private
 - Drugs:
 - Definition Legally requires prescription
 - No lifestyle drugs except erectile dysfunction
 - Erectile dysfunction \$1,200/year
 - Private Duty Nursing \$10,000/year
 - Paramedical services \$500 per year for all paramedical services

combined, including

- Physiotherapist
 - Psychologist
 - Registered Massage Therapist
 - Speech Pathology
 - Chiropractor
 - Naturopath
 - Podiatrist
 - Chiropodist
 - Osteopath
- Hearing aids, (excludes batteries) \$525/60 months
- Vision Care \$300/person/24 months
 - Laser Eye Surgery
 - Eye Exams Included
- Out-of-Country No Benefit
- Survivor Benefit Until age 65
- Dental Care:
 - Deductible Nil
 - Coinsurance
 - Basic 80%
 - Major 50%
 - Orthodontics – No benefit
 - Maximum \$1,500/calendar year
 - Fee Guide Current ODA
 - Recall 6 months
 - Survivor Benefit Until age 65

APPENDIX B – EMPLOYEE DATA

The following tables provide a summary of the employee data as of July 4, 2005. There is one retiree who is eligible. Inactive employees are not eligible.

The following tables provide some detail on the distribution of employees.

Number	342
Average Salary	\$65,796
Average Age	45.94
Average Service	14.30

Age	Number
20-25	3
25-29	24
30-34	23
35-39	35
40-44	72
45-49	59
50-54	63
55-59	36
60-64	23
65-69	4
Total	342

Service at Retirement	Number of Employees
10	23
10-11	5
11-12	5
12-13	4
13-14	3
14-15	2
15+	305

APPENDIX C – ACTUARIAL BASIS

Actuarial Cost Method

The projected Unit Credit actuarial cost method, prorated using service, was used to determine the actuarial liabilities for the post-retirement non-pension benefits, in accordance with CICA 3461.

The Unit Credit method assumes that a unit of benefit accrues in each year of service up to the full eligibility date. Under this method, the total benefits payable at retirement are calculated. The benefits are then allocated to individual years of service by prorating based on service up to the full eligibility date.

Under the projected Unit Credit actuarial cost method, the normal actuarial cost is equal to the actuarial present value of the benefits arising in respect of service during the year following the valuation date.

Economic Assumptions

- Discount Rate

The discount rate used is 5.25% per annum.

Demographic Assumptions

- Retirement Rates

I have assumed that 50% of the employees will retire at first eligibility and the balance will retire at age 65.

- Rates of Termination of Employment

I have made an allowance for future terminations of employment before retirement for reasons other than death or retirement. Sample termination

rates by employee group are shown in the following table.

Age	Percentage of Employees Terminating
20	10.0%
25	10.0%
30	5.6%
35	3.2%
40	2.2%
45	1.7%
50	1.2%
55+	0.0%

- **Mortality Rates**

I have assumed that the mortality rates, both before and after retirement, would follow the UP1994 Mortality Table projected to 2015.

- **Disability Rates**

I have made no explicit allowance for the possibility that employees become disabled before retirement.

- **Family Composition**

I have used the same single/family coverage as is currently applicable.

Claims Cost Assumptions

- Per Capita Costs

The assumed medical and dental per capita claims costs for the period beginning January 1, 2006 are as follows:

	Dental	Extended Health Care
Single	39	55
Family	100	160

- Medical and Dental Cost Increases

Medical and dental cost increases are assumed to increase from the assumed 2006 levels as follows:

- Extended Health Care cost increases: 15% in 2006 grading down to 4% per annum after 10 years
- Dental cost increases: 5% in 2006 grading down to 3% per annum after 10 years

- Administration Expenses and Premium and Sales Taxes

Administration expenses are included in the claims costs as the costs were derived from the insurer's premium rates. 8% has been added to reflect provincial sales tax

K. Paul Duxbury, F.S.A., F.C.I.A.
Actuarial Consulting Services

1164 Hunt Club Road
Cambridge, ON N3E 1A1

Phone: (519) 249-0083
1-888-791-9290
Fax: (519) 249-0084
1-888-791-9307
Cell: (905) 691-7126
Email: pduxbury@rogers.com

March 2, 2007

Mr. Don Williamson
Senior Account Manager
The Williamson Group
225 King George Rd
Brantford, ON N3R 7N7

Re: Enersource Early Retirement Benefit Plan

As requested, I have prepared a valuation as at January 1, 2007 of life insurance program that Enersource Corporation provides to its employees who retire after age 55.

A description of these benefits is included in Appendix A.

The employee data for purposes of this valuation was provided by Enersource Corporation as at January 1, 2007. A summary of the employee data is included as Appendix B.

The actuarial assumptions used are summarized in Appendix C.

The following tables indicate the financial information for the post-retirement non-pension benefits as of January 1, 2007 determined in accordance with CICA 3461.

Change in Benefit Obligation for 2006	
Benefit obligation, beginning of year	\$2,140,000
Actuarial losses (gains)	138,000
Benefits paid in 2006	(70,600)
Service cost for benefits earned during 2006	81,100
Interest cost	122,000
Benefit obligation, end of year	\$2,410,500
Net post-retirement benefit expense (2006)	\$203,400

Net post-retirement benefit expense (2007)	
Service cost for benefits earned during 2007	\$77,800
Interest cost	130,600
Net post-retirement benefit expense (2007)	\$208,400

A 1/2% increase (decrease) in the interest assumption would decrease (increase) the post-retirement benefit obligation and the service cost by approximately 7%-8%.

The **benefit obligation** is the present value of the benefits attributed to employee service rendered prior to the valuation date.

The **expected average remaining service lifetime** is the average expected amount of service that current employees will accrue in the future up to their first eligibility for benefits under the plan. This has been calculated to be 8.55 years at January 1, 2007.

To determine the employer's expense for financial statement purposes, items that are to be amortized are amortized on a straight line basis over the expected average remaining service lifetime.

The **service cost for benefits earned during the year** is the present value of benefits attributed to the one year of service following the valuation date.

Because the benefit obligation reflects a discount for interest, it is necessary to add an interest cost calculated at the valuation rate of interest.

The **net post-retirement benefit expense** is the sum of the amount of the amortization of plus the interest plus the service cost.

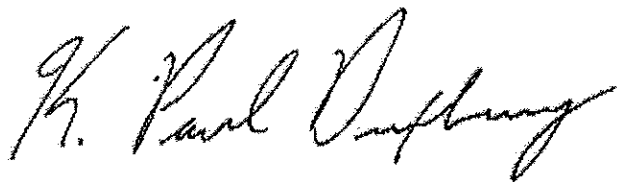
This valuation was based on the employee data provided by Enersource Corporation. I have reviewed the data for reasonableness and internal consistency. In my opinion, the data is sufficient and reliable for the purpose of this valuation.

The actuarial assumptions are management's best estimate.

In my opinion, the assumptions are appropriate for the purpose of this valuation. Emerging experience under the Plans may be different from the assumptions and may result in gains and losses which will be revealed in future valuations.

In my opinion, the methods adopted are in accordance with the requirements of the CICA Handbook. This report has been prepared and my opinions have been given in accordance with generally accepted actuarial practice.

Yours truly,

A handwritten signature in black ink, reading "K. Paul Duxbury". The signature is written in a cursive, flowing style with a large, prominent initial "K".

K. Paul Duxbury

APPENDIX A – PLAN PROVISIONS

The following is a summary of the post-retirement life insurance plan valued in the Report. Complete details are available in the insurance contracts, employee booklets, and plan documents. Other post-retirement benefit plans are valued in a separate report.

Employees on short-term disability continue to be eligible for the benefits plans available to active employees. No provision is made for this benefit.

Eligibility

All hourly and salaried employees who attain age 65 or who retire from active service with Enersource Corporation on or after age 55 and who are in receipt of a pension will be eligible.

Employee Contributions

None

Post-retirement Life Insurance Coverage

The chart below sets out the amount of post-retirement life insurance coverage:

Criteria	Amount
Hired prior to April 1, 2000 and retired with less than 10 years of service	\$2,000
Retired with 10 or more years of service and hired between March 1, 1980 and April 1, 2000 or elected additional optional life insurance at any time	50% of final earnings, decreasing by 2.5% for 10 years
Retired with 10 or more years of service and hired between May 1, 1967 and March 1, 1980 and never elected additional optional life insurance	50% of final earnings
Retired with 10 or more years of service and hired before May 1, 1967 and never elected additional optional life insurance	105% of final earnings
Hired after to April 1, 2000 and retired with less than 10 years of service	\$5,000
Hired after to April 1, 2000 and retired with 10 or more years of service	\$10,000

APPENDIX B – EMPLOYEE DATA

The following tables provide a summary of the employee data as of January 2007.

The following tables provide some detail on the distribution of employees.

Active Employees	
Number	332
Average Salary	\$67,018
Average Age	45.62
Average Service	14.17

Retirees	
Number	106
Average Coverage at 1/1/2007	\$21,425
Average Age	71.73
Average Service at retirement	22.30

APPENDIX C – ACTUARIAL BASIS

Actuarial Cost Method

The projected Unit Credit actuarial cost method, prorated using service, was used to determine the actuarial liabilities for the post-retirement non-pension benefits, in accordance with CICA 3461.

The Unit Credit method assumes that a unit of benefit accrues in each year of service up to the full eligibility date. Under this method, the total benefits payable at retirement are calculated. The benefits are then allocated to individual years of service by prorating based on service up to the full eligibility date.

Under the projected Unit Credit actuarial cost method, the normal actuarial cost is equal to the actuarial present value of the benefits arising in respect of service during the year following the valuation date.

Economic Assumptions

- Discount Rate

The discount rate used is 5.25% per annum. (6.5% was used in prior valuation)

- Salary Scale

Salaries were assumed to increase at the rate of 2.5% per annum (3.5% was used in prior valuation)

Demographic Assumptions

- Retirement Rates

I have assumed that 50% of the employees will retire at age 55, or attained age, if already over 55, and the balance will retire at age 65. (In the prior valuation, rates of retirement of 4.46% from ages 55

through 59, increasing to 13.05% at age 64 and 100% at age 65 were used.)

- Rates of Termination of Employment

I have made an allowance for future terminations of employment before retirement for reasons other than death or retirement. Sample termination rates by employee group are shown in the following table.

Age	Percentage of Employees Terminating	
	Current	Prior
20	10.0%	
25	10.0%	8.35%
30	5.6%	
35	3.2%	4.67%
40	2.2%	
45	1.7%	2.37%
50	1.2%	
55+	0.0%	6.8% (age 55)

- Mortality Rates

I have assumed that the mortality rates, both before and after retirement, would follow the UP1994 Mortality Table projected to 2015. (The UP 1994 Table without projection was used in the prior valuation.)

- Disability Rates

I have made no explicit allowance for the possibility that employees become disabled before retirement. (Disability rates; e.g., rates per thousand members: 0.144 at age 25, 0.18 at age 35, 0.66 at age 45, 2.08 at age 55, were used in the previous valuation.)

- Administration Expenses and Premium and Sales Taxes

Administration expenses are included in the claims costs as the costs were derived from the insurer's premium rates. 8% has been added to reflect provincial sales tax



Ministry of Finance
Corporations Tax
33 King Street West
PO Box 620
Oshawa ON L1H 8E9

2007

CT23 Corporations Tax and Annual Return

Corporations Tax Act - Ministry of Finance (MOF)
Corporations Information Act - Ministry of Government Services (MGS)

For taxation years commencing after December 31, 2004

This form is a combination of the Ministry of Finance (MOF) CT23 Corporations Tax Return and the Ministry of Government Services (MGS) Annual Return. Page 1 is a common page required for both Returns. For tax purposes, depending on which criteria the corporation satisfies, it must complete either the Exempt from Filing (EFF) declaration on page 2 or file the CT23 Return on pages 3-17. Corporations that do not meet the EFF criteria but do meet the Short-Form criteria, may request and file the CT23 Short-Form Return (see page 2).

The Annual Return (common page 1 and MGS Schedule A on pages 18 and 19, and Schedule K on page 20) contains non-tax information collected under the authority of the *Corporations Information Act* for the purpose of maintaining a public database of corporate information. This return must be completed by Ontario share-capital corporations or Foreign-Business share-capital corporations that have an extra-provincial licence to operate in Ontario.

MGS Annual Return Required? (Not required if already filed or Annual Return exempt. Refer to Guide) ☒ Yes ☐ No Page 1 of 20

Ministry Use
CLIENT COPY

Corporation's Legal Name (including punctuation)

Enersource Hydro Mississauga Inc.

Mailing Address

3240 Mavis Road

Mississauga

ON CA L5C 3K1

Has the mailing address changed since last filed CT23 Return? ☐ Yes

Date of Change

year month day

Registered/Head Office Address

3240 Mavis Road

Mississauga

ON CA L5C 3K1

Location of Books and Records

3240 Mavis Road

Mississauga

ON CA L5C 3K1

Name of person to contact regarding this CT23 Return

Telephone No.

Fax No.

Address of Principal Office in Ontario (Extra-Provincial Corporations only)

(MGS)

Ontario Canada

Former Corporation Name (Extra-Provincial Corporations only)

☒ Not Applicable

(MGS)

Information on Directors/Officers/Administrators must be completed on MGS Schedule A or K as appropriate. If additional space is required for Schedule A, only this schedule may be photocopied. State number submitted (MGS).

No. of Schedule(s)

If there is no change to the Directors/Officers/Administrators' information previously submitted to MGS, please check (X) this box. Schedule(s) A and K are not required (MGS).

☒ No Change

Ontario Corporations Tax Account No. (MOF)
1800247

This Return covers the Taxation Year

Start year month day
2006-01-01

End year month day
2006-12-31

Date of Incorporation or Amalgamation

year month day
2000-12-06

Ontario
Corporation No.
(MGS)

1453420

Canada Revenue Agency Business No.

If applicable, enter

88267 0920 RC0001

Jurisdiction
Incorporated

Ontario

If not incorporated in Ontario, indicate the date Ontario business activity commenced and ceased:

Commenced year month day

Ceased year month day

☒ Not Applicable

Preferred Language / Langue de préférence

☒ English
anglais ☐ French
français

Ministry Use



Certification (MGS)

I certify that all information set out in the Annual Return is true, correct and complete.

Name of Authorized Person (Print clearly or type in full)

Title ☐ Director ☐ Officer ☐ Other individuals having knowledge of the Corporation's business activities

Note: Sections 13 and 14 of the *Corporations Information Act* provide penalties for making false or misleading statements or omissions.

Enersource Hydro Mississauga Inc.

1800247

2006-12-31

CT23 Corporations Tax Return

Identification continued (for CT23 filers only)

Please check applicable (X) box(es) and complete required information.

Type of corporation

- 1** ☒ Canadian-controlled Private (CCPC) all year (Generally a private corporation of which 50% or more shares are owned by Canadian residents.) (fed.s.125(7)(b))
- 2 ☐ Other Private
- 3 ☐ Public
- 4 ☐ Non-share Capital
- 5 ☐ Other (specify) ▼

Share Capital with full voting rights
owned by Canadian Residents (nearest percent) 100 %

- 2** 1 ☐ Family Farm corporation s.1(2)
- 2 ☐ Family Fishing corporation s.1(2)
- 3 ☐ Mortgage Investment corporation s.47
- 4 ☐ Credit Union s.51
- 5 ☐ Bank Mortgage subsidiary s.61(4)
- 6 ☐ Bank s.1(2)
- 7 ☐ Loan and Trust corporation s.61(4)
- 8 ☐ Non-resident corporation s.2(2)(a) or (b)
- 9 ☐ Non-resident corporation s.2(2)(c)
- 10 ☐ Mutual Fund corporation s.48
- 11 ☐ Non-resident owned Investment corporation s.49
- 12 ☐ Non-resident ship or aircraft under reciprocal agreement with Canada s.28(b)
- 14 ☐ Bare Trustee corporation
- 15 ☐ Branch of Non-resident s.63(1)
- 16 ☐ Financial institution prescribed by Regulation only
- 17 ☐ Investment Dealer
- 18 ☐ Generator of electrical energy for sale or producer of steam for use in the generation of electrical energy for sale
- 19 ☒ Hydro successor, municipal electrical utility or subsidiary of either
- 20 ☐ Producer and seller of steam for uses other than for the generation of electricity
- 21 ☐ Insurance Exchange s.74.4
- 22 ☐ Farm Feeder Finance Co-operative corporation
- 23 ☐ Professional corporation (incorporated professionals only)

☐ This is the first year filing after incorporation or an amalgamation (If checked, attach Ontario Schedule 24.)

☐ Amended Return

☐ Taxation year end change – Canada Revenue Agency approval required

☐ Final taxation year up to dissolution (Note: for discontinued businesses, see guide.)

☐ Final taxation year before amalgamation

☐ The corporation has a floating fiscal year end

☐ There has been a transfer or receipt of asset(s) involving a corporation having a Canadian permanent establishment outside Ontario

☐ There was an acquisition of control to which subsection 249(4) of the federal *Income Tax Act* (ITA) applies since the previous taxation year

If checked, date control was acquired

year month day

☐ The corporation was involved in a transaction where all or substantially all (90% or more) of the assets of a non-arm's length corporation were received in the taxation year and subsection 85(1) or 85(2) of the federal ITA applied to the transaction (If checked, attach Ontario Schedule 44.)

☐ First year filing of a parent corporation after winding-up a subsidiary corporation(s) under section 88 of the federal ITA during the taxation year. (If checked, attach Ontario Schedule 24.)

☐ Section 83.1 of the CTA applies (redirection of payments for certain electricity corporations)

Yes No

☐ ☒ Was the corporation inactive throughout the taxation year?

☒ ☐ Has the corporation's Federal T2 Return been filed with the Canada Revenue Agency?

Are you requesting a refund due to:

☐ ☒ the Carry-back of a Loss?

☐ ☒ an Overpayment?

☐ ☒ a Specified Refundable Tax Credit?

☐ ☒ Are you a member of a Partnership or Joint Venture?

Complete if applicable

Ontario Retail Sales Tax Vendor
Permit no. (Use head office no.)

Ontario Employer Health Tax
Account no. (Use head office no.)

Specify major business activity

Hydro Utility

Income Tax

CT23 Page 4 of 20

Allocation – If you carry on a business through a permanent establishment in a jurisdiction outside Ontario, you may allocate that portion of taxable income deemed earned in that jurisdiction to that jurisdiction (s.39) (Int.B. 3008).

DOLLARS ONLY

Net Income (loss) for Ontario purposes (per reconciliation schedule, page 15) + From 690 28,493,430

Subtract: Charitable donations - 1

Subtract: Gifts to Her Majesty in right of Canada or a province and gifts of cultural property (Attach schedule 2) - 2

Subtract: Taxable dividends deductible, per federal Schedule 3 - 3

Subtract: Ontario political contributions (Attach Schedule 2A) (Int.B. 3002R) - 4

Subtract: Federal Part VI.1 tax - 5

Subtract: Prior years' losses applied – Non-capital losses - From 704

Net capital losses (page 16) From 715 x inclusion rate 50.000000% = 714

Farm losses - From 724

Restricted farm losses - From 734

Limited partnership losses - From 754

Taxable Income (Non-capital loss) = 10 28,493,430

Addition to taxable income for unused foreign tax deduction for federal purposes + 11

Adjusted Taxable Income 10 + 11 (if 10 is negative, enter 11) = 20 28,493,430

Taxable Income

From 10 (or 20 if applicable) 28,493,430 x 30 100.0000% x 12.5% x 33 365 = + 29

From 10 (or 20 if applicable) 28,493,430 x 30 100.0000% x 14% x 34 365 = + 32 3,989,080

Income Tax Payable (before deduction of tax credits) 29 + 32 = 40 3,989,080

Incentive Deduction for Small Business Corporations (IDSBC) (s.41)

If this section is not completed, the IDSBC will be denied.

Did you claim the federal Small Business Deduction (fed.s.125(1)) in the taxation year or would you have claimed the federal Small Business Deduction had the provisions of fed.s.125(5.1) not been applicable in the taxation year? (X)

☒ Yes ☐ No

* Income from active business carried on in Canada for federal purposes (fed.s.125(1)(a)) 50 28,493,430

Federal taxable income, less adjustment for foreign tax credit (fed.s.125(1)(b)) + 51 28,493,430

Add: Losses of other years deducted for federal purposes (fed.s.111) + 52

Subtract: Losses of other years deducted for Ontario purposes (s.34) - 53

Federal Business limit (line 410 of the T2 Return) for the year before the application of fed.s.125(5.1) = 28,493,430 54 28,493,430

Ontario Business Limit Calculation

320,000 x 31 365 = + 46

400,000 x 34 365 = + 47 400,000

Business Limit for Ontario purposes 46 + 47 = 44 400,000

Percentage of Federal Business limit (from T2 Schedule 23). Enter 100% if not associated. 48 100.0000% = 45 400,000

Income eligible for the IDSBC From 30 100.0000% x 56 400,000 = 60 400,000

***Ontario Allocation Least of 50, 54 or 45

* Note: Modified by s.41(6) and (7) for corporations that are members of a partnership. (Refer to Guide.)

** Note: Adjust accordingly for a floating taxation year and use 366 for a leap year.

*** Note: Ontario Allocation for IDSBC purposes may differ from 30 if Taxable Income is allocated to foreign jurisdictions. See special rules (s.41(4)).

continued on Page 5

Income Tax continued from Page 4

Calculation of IDSBC Rate

	7 %	x	<table border="1"> <tr> <th colspan="2">Number of Days in Taxation Year</th> </tr> <tr> <td>Days after Dec. 31, 2002 and before Jan. 1, 2004</td> <td>Total Days</td> </tr> <tr> <td>31</td> <td>365</td> </tr> </table>	Number of Days in Taxation Year		Days after Dec. 31, 2002 and before Jan. 1, 2004	Total Days	31	365	=	+	89			
Number of Days in Taxation Year															
Days after Dec. 31, 2002 and before Jan. 1, 2004	Total Days														
31	365														
	8.5 %	x	<table border="1"> <tr> <th colspan="2">Number of Days in Taxation Year</th> </tr> <tr> <td>Days after Dec. 31, 2003</td> <td>Total Days</td> </tr> <tr> <td>34</td> <td>365</td> </tr> <tr> <td>73</td> <td>365</td> </tr> </table>	Number of Days in Taxation Year		Days after Dec. 31, 2003	Total Days	34	365	73	365	=	+	90	8.5000
Number of Days in Taxation Year															
Days after Dec. 31, 2003	Total Days														
34	365														
73	365														
IDSBC Rate for Taxation Year				=	+	78	8.5000								
Claim			From 60 400,000	x	From 78 8.5000 %		= 70 34,000								

Corporations claiming the IDSBC must complete the Surtax section below if the corporation's taxable income (or if associated, the associated group's taxable income) is greater than the amount 400,000 in 114 below.

Surtax on Canadian-controlled Private Corporations (s.41.1)

Applies if you have claimed the Incentive Deduction for Small Business Corporations.

Associated Corporation - The Taxable Income of associated corporations is the taxable income for the taxation year ending on or before the date of this corporation's taxation year end.

*Taxable Income of the corporation From 10 (or 20 if applicable) + 80 28,493,430

If you are a member of an associated group (X) 81 X (Yes)

Name of associated corporation (Canadian & foreign) (if insufficient space, attach schedule)	Ontario Corporations Tax Account No. (MOF) (if applicable)	Taxation Year End	* Taxable Income (if loss, enter nil)
See schedule			+ 82 151,339
			+ 83
			+ 84
Aggregate Taxable Income	80 + 82 + 83 + 84, etc.		= 85 28,644,769

Number of Days in Taxation Year

320,000 x	<table border="1"> <tr> <th colspan="2">Number of Days in Taxation Year</th> </tr> <tr> <td>Days after Dec. 31, 2002 and before Jan. 1, 2004</td> <td>Total Days</td> </tr> <tr> <td>31</td> <td>365</td> </tr> </table>	Number of Days in Taxation Year		Days after Dec. 31, 2002 and before Jan. 1, 2004	Total Days	31	365	=	+	115			
Number of Days in Taxation Year													
Days after Dec. 31, 2002 and before Jan. 1, 2004	Total Days												
31	365												
400,000 x	<table border="1"> <tr> <th colspan="2">Number of Days in Taxation Year</th> </tr> <tr> <td>Days after Dec. 31, 2003</td> <td>Total Days</td> </tr> <tr> <td>34</td> <td>365</td> </tr> <tr> <td>73</td> <td>365</td> </tr> </table>	Number of Days in Taxation Year		Days after Dec. 31, 2003	Total Days	34	365	73	365	=	+	116	400,000
Number of Days in Taxation Year													
Days after Dec. 31, 2003	Total Days												
34	365												
73	365												
				115 + 116	= 400,000								
(If negative, enter nil)					- 114 400,000								
					= 86 28,244,769								

Calculation of Specified Rate for Surtax

	4.6670 %	x	<table border="1"> <tr> <th colspan="2">Number of Days in Taxation Year</th> </tr> <tr> <td>Days after Dec. 31, 2002</td> <td>Total Days</td> </tr> <tr> <td>38</td> <td>365</td> </tr> <tr> <td>73</td> <td>365</td> </tr> </table>	Number of Days in Taxation Year		Days after Dec. 31, 2002	Total Days	38	365	73	365	=	+	97	4.6670
Number of Days in Taxation Year															
Days after Dec. 31, 2002	Total Days														
38	365														
73	365														
From 86 28,244,769	x	From 97 4.6670 %		=	87	1,318,183									
From 87 1,318,183	x	From 60 400,000	÷	From 114 400,000	=	88 1,318,183									
Surtax Lesser of	70 or 88			=	100	34,000									

* Note: Short Taxation Years - Special rules apply where the taxation year is less than 51 weeks for the corporation and/or any corporation associated with it.

continued on Page 6

Additional Deduction for Credit Unions (s.51(4)) (Attach schedule 17)

110

Manufacturing and Processing Profits Credit (M&P) (s.43)

Applies to Eligible Canadian Profits from manufacturing and processing, farming, mining, logging and fishing carried on in Canada, as determined by regulations.

Eligible Canadian Profits from mining are the "resource profits from the mining operations", as determined for Ontario depletion purposes, after deducting depletion and resource allowances but excluding amounts from sale of Canadian resource property, rentals or royalties. If you are claiming this credit, attach a copy of Ontario schedule 27.

The whole of the active business income qualifies as Eligible Canadian Profits if: a) your active business income from sources other than manufacturing and processing, mining, farming, logging or fishing is 20% or less of the total active business income and b) the total active business income is \$250,000 or less.

Eligible Canadian Profits

Subtract: Income eligible for the Incentive Deduction for Small Business Corporations (IDSBC) - From 56 400,000

Add: Adjustment for Surtax on Canadian-controlled private corporations

$$\frac{\text{From } 100 \text{ } 34,000}{\text{From } 30 \text{ } 100.0000\%} \div \frac{\text{From } 78 \text{ } 8.5000\%}{\text{Ontario Allocation}} = 121 \text{ } 400,000$$

Lesser of 56 or 121 + 122 400,000

120 - 56 + 122 = 130

Taxable Income + From 10 28,493,430

Subtract: Income eligible for the Incentive Deduction for Small Business Corporations (IDSBC) - From 56 400,000

Add: Adjustments for Surtax on Canadian-controlled private corporations + From 122 400,000

Subtract: Taxable Income 10 28,493,430 X Allocation % to jurisdictions outside Canada - 140

Subtract: Amount by which Canadian and foreign investment income exceeds net capital losses - 141

10 - 56 + 122 - 140 - 141 = 142 28,493,430

Claim

$$\frac{143 \text{ } 143}{\text{Lesser of } 130 \text{ or } 142} \times \text{From } 30 \text{ } 100.0000\% \times 1.5\% \times \frac{\text{Days after Dec. 31, 2002 and before Jan. 1, 2004 } 33}{\text{Total Days } 365} = + 154$$

$$\frac{143 \text{ } 143}{\text{Lesser of } 130 \text{ or } 142} \times \text{From } 30 \text{ } 100.0000\% \times 2\% \times \frac{\text{Days after Dec. 31, 2003 } 34}{\text{Total Days } 365} = + 156$$

M&P claim for taxation year 154 + 156 = 160

* Note: Ontario Allocation for M&P Credit purposes may differ from 30 if Taxable Income is allocated to foreign jurisdictions. See special rules (s.43(1))

Manufacturing and Processing Profits Credit for Electrical Generating Corporations

161

Manufacturing and Processing Profits Credit for Corporations that Produce and Sell Steam for uses other than the Generation of Electricity

162

Credit for Foreign Taxes Paid (s.40)

Applies if you paid tax to a jurisdiction outside Canada on foreign investment income (Int.B. 3001R). (Attach schedule)

170

Credit for Investment in Small Business Development Corporations (SBDC)

Applies if you have an unapplied, previously approved credit from prior years' investments in new issues of equity shares in Small Business Development Corporations. Any unused portion may be carried forward indefinitely and applied to reduce subsequent years' income taxes. (Refer to the former Small Business Development Corporations Act)

Eligible Credit 175

Credit Claimed 180

Subtotal of Income Tax 40 - 70 + 100 - 110 - 160 - 161 - 162 - 170 - 180 = 190 3,989,080

continued on Page 7

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Income Tax *continued from Page 6***Specified Tax Credits** (Refer to Guide)**Ontario Innovation Tax Credit (OITC) (s.43.3)** *Applies to scientific research and experimental development in Ontario.*Eligible Credit From **5620** OITC Claim Form (Attach original Claim Form)+ **191****Co-operative Education Tax Credit (CETC) (s.43.4)** *Applies to employment of eligible students.*Eligible Credit From **5798** CT23 Schedule 113 (Attach Schedule 113)+ **192** 8,000**Ontario Film & Television Tax Credit (OFTTC) (s.43.5)***Applies to qualifying Ontario labour expenditures for eligible Canadian content film and television productions.* Name of Production **204**Eligible Credit From **5850** of the Certificate of Eligibility issued by the Ontario Media Development Corporation (OMDC)
(Attach the original Certificate of Eligibility)+ **193****Graduate Transitions Tax Credit (GTTC) (s.43.6)***Applies to employment of eligible unemployed post secondary graduates, for employment commencing prior to July 6, 2004 and expenditures incurred prior to January 1, 2005.*No. of Graduates From **6596**Eligible Credit From **6598** CT23 Schedule 115 (Attach Schedule 115)**194**+ **195****Ontario Book Publishing Tax Credit (OBPTC) (s.43.7)***Applies to qualifying expenditures in respect of eligible literary works by eligible Canadian authors.*Eligible Credit From **6900** OBPTC Claim Form (Attach both the original Claim Form and the Certificate of Eligibility)+ **196****Ontario Computer Animation and Special Effects Tax Credit (OCASE) (s.43.8)***Applies to labour relating to computer animation and special effects on an eligible production.*Eligible Credit From **6700** of the Certificate of Eligibility issued by the Ontario Media Development Corporation (OMDC)
(Attach the original Certificate of Eligibility)+ **197****Ontario Business-Research Institute Tax Credit (OBRITC) (s.43.9)***Applies to qualifying R&D expenditures under an eligible research institute contract.*Eligible Credit From **7100** OBRITC Claim Form (Attach original Claim Form)+ **198****Ontario Production Services Tax Credit (OPSTC) (s.43.10)***Applies to qualifying Ontario labour expenditures for eligible productions where the OFTTC has not been claimed.*Eligible Credit From **7300** of the Certificate of Eligibility issued by the Ontario Media Development Corporation (OMDC)
(Attach the original Certificate of Eligibility)+ **199****Ontario Interactive Digital Media Tax Credit (OIDMTC) (s.43.11)***Applies to qualifying labour expenditures of eligible products for the taxation year.*Eligible Credit From **7400** of the Certificate of Eligibility issued by the Ontario Media Development Corporation (OMDC)
(Attach the original Certificate of Eligibility)+ **200****Ontario Sound Recording Tax Credit (OSRTC) (s.43.12)***Applies to qualifying expenditures in respect of eligible Canadian sound recordings.*Eligible Credit From **7500** OSRTC Claim Form (Attach both the original Claim Form and the Certificate of Eligibility)+ **201****Apprenticeship Training Tax Credit (ATTC) (s.43.13)***Applies to employment of eligible apprentices.*Eligible Credit From **5898** CT23 Schedule 114 (Attach Schedule 114)No. of Apprentices From **5896****202** 8+ **203** 27,288

Other (specify) _____

+ **203.1****Total Specified Tax Credits** **191** + **192** + **193** + **195** + **196** + **197** + **198** + **199** + **200** + **201** + **203** + **203.1**= **220** 35,288**Specified Tax Credits Applied to reduce Income Tax**= **225** 35,288**Income Tax** **190** - **225** OR Enter NIL if reporting Non-Capital Loss (amount cannot be negative)= **230** 3,953,792To determine if the Corporate Minimum Tax (CMT) is applicable to your Corporation, see **Determination of Applicability** section for the CMT on Page 8. If CMT is not applicable, transfer amount in **230** to Income Tax in Summary section on Page 17.

OR

If CMT is not applicable for the current taxation year but your corporation has CMT Credit Carryovers that you want to apply to reduce income tax otherwise payable, then proceed to and complete the **Application of CMT Credit Carryovers** section part B, on Page 8.

Corporate Minimum Tax (CMT)

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DOLLARS ONLY

Total Assets of the corporation + [240] 587,749,000 .
 Total Revenue of the corporation + [241] 674,161,000 .

The above amounts include the corporation's and associated corporations' share of any partnership(s) / joint venture(s) total assets and total revenue.

If you are a member of an associated group (X) [242] ☒ (Yes)

Name of associated corporation (Canadian & foreign) (if insufficient space attach schedule)	Ontario Corporations Tax Account No. (MOF) (if applicable)	Taxation Year End	Total Assets	Total Revenue
See schedule			+ [243] 245,426,000 .	+ [244] 24,754,000 .
			+ [245] .	+ [246] .
			+ [247] .	+ [248] .
Aggregate Total Assets	[240] + [243] + [245] + [247], etc.		= [249] 833,175,000 .	
Aggregate Total Revenue	[241] + [244] + [246] + [248], etc.			= [250] 698,915,000 .

Determination of Applicability

Applies if either Total Assets [249] exceeds \$5,000,000 or Total Revenue [250] exceeds \$10,000,000.

Short Taxation Years – Special rules apply for determining total revenue where the taxation year of the corporation or any associated corporation or any fiscal period of any partnership(s) / joint venture(s) of which the corporation or associated corporation is a member, is less than 51 weeks.

Associated Corporation – The total assets or total revenue of associated corporations is the total assets or total revenue for the taxation year ending on or before the date of the claiming corporation's taxation year end.

If CMT is applicable to current taxation year, complete section Calculation: CMT below and Corporate Minimum Tax Schedule 101.

Calculation: CMT (Attach Schedule 101.)

Gross CMT Payable CMT Base From Schedule 101 [2136] 23,420,000 . X From [30] 100.0000 % X 4 % = [276] 936,800 .
 If negative, enter zero Ontario Allocation

Subtract: Foreign Tax Credit for CMT purposes (Attach Schedule) [277] .
 Subtract: Income Tax From [190] 3,989,080 .

Net CMT Payable (If negative, enter Nil on Page 17.) = [280] -3,052,280 .

If [280] is less than zero and you do not have a CMT credit carryover, transfer [230] from Page 7 to Income Tax Summary, on Page 17.

If [280] is less than zero and you have a CMT credit carryover, complete A & B below.

If [280] is greater than or equal to zero, transfer [230] to Page 17 and transfer [280] to Page 17, and to Part 4 of Schedule 101: Continuity of CMT Credit Carryovers.

CMT Credit Carryover available From Schedule 101 From [2333] .

Application of CMT Credit Carryovers

A. Income Tax (before deduction of specified credits) + From [190] 3,989,080 .
 Gross CMT Payable + From [276] 936,800 .
 Subtract: Foreign Tax Credit for CMT purposes - From [277] .
 If [276] - [277] is negative, enter NIL in [290] = 936,800 .
 Income Tax eligible for CMT Credit = [290] 936,800 .
 [300] 3,052,280 .

B. Income Tax (after deduction of specified credits) + From [230] 3,953,792 .
 Subtract: CMT credit used to reduce income taxes - [310] .
 Income Tax = [320] 3,953,792 .
 Transfer to page 17

If A & B apply, [310] cannot exceed the lesser of [230], [300] and your CMT credit carryover available [2333] .

If only B applies, [310] cannot exceed the lesser of [230] and your CMT credit carryover available [2333] .

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Capital Tax (Refer to Guide and Int.B. 3011R)

If your corporation is a Financial Institution (s.58(2)), complete lines 480 and 430 on page 10 then proceed to page 13.

If your corporation is not a member of an associated group and/or partnership and the Gross Revenue and Total Assets as calculated on page 10 in 480 and 430 are both \$3,000,000 or less, your corporation is exempt from Capital Tax for the taxation year, except for a branch of a non-resident corporation. A corporation that meets these criteria should disregard all other Capital Tax items (including the calculation of Taxable Capital). Enter NIL in 550 on page 12 and complete the return from that point. All other corporations must compute their Taxable Capital in order to determine their Capital Tax payable.

Members of a partnership (limited or general) or a joint venture, must attach all financial statements of each partnership or joint venture of which they are a member. The Paid-up Capital of each corporate partner must include its share of liabilities that would otherwise be included if the partnership were a corporation. If Investment Allowance is claimed, Total Assets must be

adjusted by adding the corporation's share of the partnership's Total Assets and by deducting investments in the partnership as it appears on the corporation's balance sheet, in addition to any other required adjustments (s.61(5)). Special rules apply to limited partnerships (Int.B. 3017R).

Any Assets and liabilities of a corporation that are being utilized in a joint venture must be included along with the corporation's other Assets and liabilities when calculating its Taxable Paid-up Capital.

Special rules and rates apply to Non-Resident corporations (s.63, s.64 and s.69(3)).

Paid-up Capital of Non-resident: Paid-up capital employed in Canada of a non-resident subject to tax by virtue of s.2(2)(a) or 2(2)(b), and whose business is not carried on solely in Canada is deemed to be the greater of (1) taxable Income in Canada divided by 8 percent or (2) total assets in Canada minus certain indebtedness in accordance with the provisions of s.63(1)(a) (Int.B. 3010).

Paid-up Capital

Paid-up capital stock (Int.B. 3012R and 3015R)		+	350	155,629,000
Retained earnings (if deficit, deduct) (Int.B. 3012R)		±	351	27,136,000
Capital and other surpluses, excluding appraisal surplus (Int.B. 3012R)		+	352	
Loans and advances (Attach schedule) (Int.B. 3013R)		+	353	25,818,216
Bank loans (Int.B. 3013R)		+	354	
Bankers acceptances (Int.B. 3013R)		+	355	
Bonds and debentures payable (Int.B. 3013R)		+	356	290,000,000
Mortgages payable (Int.B. 3013R)		+	357	
Lien notes payable (Int.B. 3013R)		+	358	
Deferred credits (including income tax reserves, and deferred revenue where it would also be included in paid-up capital for the purposes of the large corporations tax) (Int.B. 3013R)		+	359	
Contingent, investment, inventory and similar reserves (Int.B. 3012R)		+	360	
Other reserves not allowed as deductions for income tax purposes (Attach schedule) (Int.B. 3012R)		+	361	16,038,859
Share of partnership(s) or joint venture(s) paid-up capital (Attach schedule(s)) (Int.B. 3017R)		+	362	
Subtotal		=	370	514,622,075
Subtract: Amounts deducted for income tax purposes in excess of amounts booked (Retain calculations. Do not submit.) (Int.B. 3012R)		-	371	
Deductible R & D expenditures and ONTTI costs deferred for income tax if not already deducted for book purposes (Int.B. 3015R)		-	372	
Total Paid-up Capital		=	380	514,622,075
Subtract: Deferred mining exploration and development expenses (s.62(1)(d)) (Int.B. 3015R)		-	381	
Electrical Generating Corporations Only -- All amounts with respect to electrical generating assets, except to the extent that they have been deducted by the corporation in computing its income for income tax purposes for the current or any prior taxation year, that are deductible by the corporation under clause 11(10)(a) of the Corporations Tax Act, and the assets are used both in generating electricity from a renewable or alternative energy source and are qualifying property as prescribed by regulation		-	382	
Net Paid-up Capital		=	390	514,622,075

Eligible Investments (Refer to Guide and Int.B. 3015R)

Attach computations and list of corporation names and investment amounts. Short-term investments (bankers acceptances, commercial paper, etc.) are eligible for the allowance only if issued for a term of and held for 120 days or more prior to the year end of the investor corporation.

Bonds, lien notes and similar obligations, (similar obligations, e.g. stripped interest coupons, applies to taxation years ending after October 30, 1998)		+	402	
Mortgages due from other corporations		+	403	
Shares in other corporations (certain restrictions apply) (Refer to Guide)		+	404	
Loans and advances to unrelated corporations		+	405	
Eligible loans and advances to related corporations (certain restrictions apply) (Refer to Guide)		+	406	1,352,000
Share of partnership(s) or joint venture(s) eligible investments (Attach schedule)		+	407	
Total Eligible Investments		=	410	1,352,000

continued on Page 10

Total Assets (Int.B. 3015R)[illegible]

Gross Revenue (as adjusted to include the share of any partnership(s)/joint venture(s) Gross Revenue)	- - -	480	674,161,000
Total Assets (as adjusted)	- - - - -	From 430	587,749,000

Note: This version (2007) of the CT25 may only be used for a taxation year that commenced after December 31, 2004. Financial Institutions use calculations on page 13.

Important:

If the corporation is a family farm corporation, family fishing corporation or a credit union that is not a Financial Institution, complete only Section A below.

OR If the corporation is not a member of an associated group and/or partnership, complete Section B below, then review only the Capital Tax calculations in Section C on page 11, selecting and completing the one specific subsection (e.g. C3) that applies to the corporation.

OR If the corporation is a member of an associated group and/or partnership, complete Section B below and Section D on page 11, and if applicable, complete Section E or Section F on page 12. Note: if the corporation is a member of a connected partnership, please refer to the CT23 Guide for additional instructions before completing the Capital Tax section.

SECTION A

This section applies only if the corporation is a family farm corporation, a family fishing corporation or a credit union that is not a Financial Institution (Int.B. 3018).

Enter NIL in **550** on page 12 and complete the return from that point.

SECTION B

B1. Calculation of Taxable Capital Deduction (TCD)

Number of Days in Taxation Year	
Days after Dec. 31, 2004 and before Jan. 1, 2006	Total Days
7,500,000 × 36 _____ ÷ 73 365	= + 501
10,000,000 × 37 365 ÷ 73 365	= + 502 10,000,000
12,500,000 × 38 _____ ÷ 73 365	= + 504
15,000,000 × 39 _____ ÷ 73 365	= + 505
Total Deduction (TCD) 501 + 502 + 504 + 505 = 503 10,000,000	

B2. This section applies to corporations to calculate the prorated capital tax rate.

Calculation of Capital Tax Rate

Number of Days in Taxation Year

		Days before Jan. 1, 2007		Total Days			
0.3 %	x	556	<u>365</u>	÷	73	<u>365</u>	= + 511 <u>0.3000 %</u>
		Days after Dec. 31, 2006 and before Jan. 1, 2009		Total Days			
0.285 %	x	557	<u> </u>	÷	73	<u>365</u>	= + 512 <u> </u> %
Capital Tax Rate		511	+	512	- - - - -	=	516 <u>0.3000 %</u>

continued on Page 11

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Capital Tax Calculation *continued from Page 10***SECTION C**

This section applies if the corporation is not a member of an associated group and/or partnership.

C1. If and on page 10 are both \$3,000,000 or less, enter NIL in on page 12 and complete the return from that point.

C2. If Taxable Capital in is equal to or less than the TCD in , enter NIL in on page 12 and complete the return from that point.

C3. If Taxable Capital in exceeds the TCD in , complete the following calculation and transfer the amount from to on page 12, and complete the return from that point.

$$\begin{array}{rcl}
 + & \text{From } \text{470} & \bullet \\
 - & \text{From } \text{503} & \bullet \\
 = & \text{471} & \bullet
 \end{array}
 \times
 \begin{array}{c}
 \text{From } \text{30} \\
 \text{Ontario Allocation}
 \end{array}
 \frac{\text{100.0000}}{\%}
 \times
 \begin{array}{c}
 \text{From } \text{516} \\
 \text{Capital Tax Rate}
 \end{array}
 \frac{\text{0.3000}}{\%}
 \times
 \begin{array}{c}
 \text{Days in taxation year} \\
 \text{555} \quad \text{365} \\
 \text{365 (366 if leap year)} \\
 \text{If floating taxation year,} \\
 \text{refer to Guide.}
 \end{array}
 = + \text{523} \bullet$$

Transfer to on page 12 and complete the return from that point

SECTION D

This section applies ONLY to a corporation that is a member of an associated group (excluding Financial Institutions and corporations exempt from Capital Tax) and/or partnership. You must check either or and complete this section before you can calculate your Capital Tax Calculation under either Section E or Section F.

D1. ☐ (X if applicable) All corporations that you are associated with do not have a permanent establishment in Canada.
 If Taxable Capital on page 10 is equal to or less than the TCD on page 10, enter NIL in on page 12 and complete the return from that point.
 If Taxable Capital on page 10 exceeds the TCD on page 10, proceed to Section E, enter the TCD amount in in Section E, and complete Section E and the return from that point.

D2. ☒ (X if applicable) One or more of the corporations that you are associated with maintains a permanent establishment in Canada.

You and your associated group may continue to allocate the TCD by completing the Calculation below. Or, the associated group may file an election under subsection 69(2.1) of the *Corporations Tax Act*, whereby total assets are used to allocate the TCD among the associated group. Once a ss.69(2.1) election is filed, all members of the group will then be required to file in accordance with the election and allocate a portion (portion is henceforth referred to as Net Deduction) of the capital tax effect relating to the TCD to each corporation in the group on the basis of the ratio that each corporation's total assets multiplied by its Ontario allocation is to the total assets of the group.

The total asset amounts and Ontario allocation percentages to be used for this calculation must be taken from each corporation's financial information from its last taxation year ending in the immediately preceding calendar year.

In addition, although each corporation in the associated group may deduct its Net Deduction amount as apportioned by the total asset formula, the group may, at the group's option, reallocate the group's total Net Deduction among the group on what ever basis the corporate group wishes, as long as the total of the reallocated amounts does not exceed the group's total Net Deduction amount originally calculated for the associated group.

D2. Calculation is on next page

continued on Page 12

DOLLARS ONLY

D2. Calculation Do not complete this calculation if ss.69(2.1) election is filed

Taxable Capital From 470 on page 10 - - - - - + From 470 513,438,289 .

Determine aggregate taxable capital of an associated group (excluding financial institutions and corporations exempt from capital tax) and/or partnership having a permanent establishment in Canada

Names of associated corporations (excluding Financial Institutions and corporations exempt from Capital Tax) having a permanent establishment in Canada (if insufficient space, attach schedule)	Ontario Corporations Tax Account No. (MOF) (if applicable)	Taxation Year End	Taxable Capital
See schedule			+ <u>531</u> 28,180,282 .
			+ <u>532</u> .
			+ <u>533</u> .
Aggregate Taxable Capital <u>470</u> + <u>531</u> + <u>532</u> + <u>533</u> , etc.			= <u>540</u> 541,618,571 .

If 540 above is equal to or less than the TCD 503 on page 10, the corporation's Capital Tax for the taxation year, is NIL.

Enter NIL in 523 in section E below, as applicable.

If 540 above is greater than the TCD 503 on page 10, the corporation must compute its share of the TCD below in order to calculate its Capital Tax for the taxation year under Section E below.

$$\text{From } \underline{470} \quad 513,438,289 \div \text{From } \underline{540} \quad 541,618,571 \times \text{From } \underline{503} \quad 10,000,000 = \underline{541} \quad 9,479,702 .$$

Transfer to 542 in Section E below

Ss.69(2.1) Election Filed

☐ 591 (X if applicable) Election filed. Attach a copy of Schedule 591 with this CT23 Return. Proceed to Section F below.

SECTION E

This section applies if the corporation is a member of an associated group and/or partnership whose total aggregate Taxable Capital 540 above, exceeds the TCD 503 on page 10.

Complete the following calculation and transfer the amount from 523 to 543, and complete the return from that point.

$$\begin{aligned} &+ \text{From } \underline{470} \quad 513,438,289 . \\ &- \quad \underline{542} \quad 9,479,702 . \\ &= \quad \underline{471} \quad 503,958,587 . \end{aligned} \times \text{From } \underline{30} \quad 100.0000 \% \times \text{From } \underline{516} \quad 0.3000 \% \times \frac{\text{Days in taxation year}}{365} \quad \underline{555} \quad 365 = + \underline{523} \quad 1,511,876 .$$

Ontario Allocation Capital Tax Rate (366 if leap year)

Total Capital Tax for the taxation year
Transfer to 543 and complete the return from that point

SECTION F

This section applies if a corporation is a member of an associated group and the associated group has filed a ss.69(2.1) election

$$\begin{aligned} &+ \text{From } \underline{470} \quad . \times \text{From } \underline{30} \quad 100.0000 \% \times \text{From } \underline{516} \quad 0.3000 \% - - - - - = + \quad \underline{561} \quad . \\ &- \text{Capital tax deduction from } \underline{995} \text{ relating to your corporation's Capital Tax deduction, on Schedule 591} - - - - - = - \text{From } \underline{995} \quad . \\ &= \quad \underline{562} \quad . \end{aligned}$$

Ontario Allocation Capital Tax Rate

Total Capital Tax for the taxation year

$$\text{Capital Tax} - - - - - \underline{562} \quad . \times \frac{\text{Days in taxation year}}{365} \quad \underline{555} \quad 365 = \underline{563} \quad .$$

(366 if leap year)

Transfer to 543 and complete the return from that point

* If floating taxation year, refer to Guide.

$$\begin{aligned} &\text{Capital Tax before application of specified credits} - - - - - = \underline{543} \quad 1,511,876 . \\ &\text{Subtract: Specified Tax Credits applied to reduce capital tax payable (Refer to Guide)} - - - - - = \underline{546} \quad . \\ &\text{Capital Tax } \underline{543} - \underline{546} \text{ (amount cannot be negative)} - - - - - = \underline{550} \quad 1,511,876 . \end{aligned}$$

Transfer to Page 17

continued on Page 13

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Capital Tax *continued from Page 12***Calculation of Capital Tax for Financial Institutions****1.1 Credit Unions only**For taxation years commencing after May 4, 1999 enter NIL in **550** on page 12, and complete the return from that point.**1.2 Other than Credit Unions**(Retain details of calculations for amounts in boxes **565** and **570**. Do not submit with this tax return.)

$$\begin{array}{l}
 \text{Days in taxation year} \\
 \text{565} \times \text{567} \% \times \text{From } 30 \text{ } 100.0000 \% \times \frac{\text{555}}{365} \frac{365}{(366 \text{ if leap year})} = + \text{569}
 \end{array}$$

Lesser of adjusted
 Taxable Paid Up Capital
 and Basic Capital Amount
 in accordance with
 Division B.1

Capital Tax Rate (1)
(Refer to Guide)

Ontario Allocation

$$\begin{array}{l}
 \text{Days in taxation year} \\
 \text{570} \times \text{571} \% \times \text{From } 30 \text{ } 100.0000 \% \times \frac{\text{555}}{365} \frac{365}{(366 \text{ if leap year})} = + \text{574}
 \end{array}$$

Adjusted Taxable
 Paid Up Capital
 in accordance with
 Division B.1 in excess
 of Basic Capital Amount

Capital Tax Rate (2)
(Refer to Guide)

Ontario Allocation

$$\text{Capital Tax for Financial Institutions - other than Credit Unions (before Section 2)} \quad \text{569} + \text{574} = \text{575}$$

* If floating taxation year, refer to Guide.

2. Small Business Investment Tax Credit

(Retain details of eligible investment calculation and, if claiming an investment in CSBIF, retain the original letter approving the credit issued in accordance with the Community Small Business Investment Fund Act. Do not submit with this tax return.)

$$\begin{array}{l}
 \text{Allowable Credit for Eligible Investments} \\
 \text{Financial Institutions: Claiming a tax credit for investment in Community Small Business Investment Fund (CSBIF)? (X) } \quad \text{Yes}
 \end{array}$$

- **585**

$$\text{Capital Tax - Financial Institutions} \quad \text{575} - \text{585} = \text{586}$$

Transfer to **543** on Page 12

Premium Tax (s. 74.2 & 74.3) *(Refer to Guide)*

$$\begin{array}{l}
 \text{(1) Uninsured Benefits Arrangements} \\
 \text{Applies to Ontario-related uninsured benefits arrangements.}
 \end{array}$$

- **587** x 2% = **588**

$$\begin{array}{l}
 \text{(2) Unlicensed Insurance (enter premium tax payable in } \text{588} \text{ and attach a detailed schedule of calculations. If subject to tax under} \\
 \text{(1) above, add both taxes together and enter total tax in } \text{588} \text{.)} \\
 \text{Applies to Insurance Brokers and other persons placing insurance for persons resident or property situated in Ontario with} \\
 \text{unlicensed insurers.}
 \end{array}$$

$$\begin{array}{l}
 \text{Deduct: Specified Tax Credits applied to reduce premium tax (Refer to Guide)} \\
 - \text{589}
 \end{array}$$

$$\text{Premium Tax} \quad \text{588} - \text{589} = \text{590}$$

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DOLLARS ONLY

Reconcile net income (loss) for federal income tax purposes
with net income (loss) for Ontario purposes if amounts differ

Net Income (loss) for federal income tax purposes, per federal T2 Schedule 1

+ [600] 28,493,430
Transfer to Page 15

Add:

Federal capital cost allowance	+ [601]	27,877,918
Federal cumulative eligible capital deduction	+ [602]	1,568,076
Ontario taxable capital gain	+ [603]	
Federal non-allowable reserves. Balance beginning of year	+ [604]	2,140,123
Federal allowable reserves. Balance end of year	+ [605]	
Ontario non-allowable reserves. Balance end of year	+ [606]	4,079,952
Ontario allowable reserves. Balance beginning of year	+ [607]	
Federal exploration expenses (e.g. CEDE, CEE, CDE, COGPE)	+ [608]	
Federal resource allowance (Refer to Guide)	+ [609]	
Federal depletion allowance	+ [610]	
Federal foreign exploration and development expenses	+ [611]	
Crown charges, royalties, rentals, etc. deducted for Federal purposes (Refer to Guide)	+ [617]	
Management fees, rents, royalties and similar payments to non-arm's length non-residents		

Number of Days in Taxation Year

[612] $\times 5 / 12.5 \times$ [33] $\div$ [73] 365 = + [633]

[612] $\times 5 / 14 \times$ [34] 365 $\div$ [73] 365 = + [634]

Total add-back amount for Management fees, etc. [633] + [634] = + [613]

Federal Scientific Research Expenses claimed in year from line [460] of fed. form T661
excluding any negative amount in [473] from Ont. CT23 Schedule 161

+ [615]

Add any negative amount in [473] from Ont. CT23 Schedule 161

+ [616]

Federal allowable business investment loss

+ [620]

Total of other items not allowed by Ontario but allowed federally (Attach schedule)

+ [614]

Total of Additions [601] to [611] + [617] + [613] + [615] + [616] + [620] + [614] = 35,666,069 [640] 35,666,069
Transfer to Page 15

Deduct:

Ontario capital cost allowance (excludes amounts deducted under [675])	+ [650]	27,877,918
Ontario cumulative eligible capital deduction	+ [651]	1,568,076
Federal taxable capital gain	+ [652]	
Ontario non-allowable reserves. Balance beginning of year	+ [653]	2,140,123
Ontario allowable reserves. Balance end of year	+ [654]	
Federal non-allowable reserves. Balance end of year	+ [655]	4,079,952
Federal allowable reserves. Balance beginning of year	+ [656]	
Ontario exploration expenses (e.g. CEDE, CEE, CDE, COGPE) (Retain calculations. Do not submit.)	+ [657]	
Ontario depletion allowance	+ [658]	
Ontario resource allowance (Refer to Guide)	+ [659]	
Ontario current cost adjustment (Attach schedule)	+ [661]	
CCA on assets used to generate electricity from natural gas, alternative or renewable resources.	+ [675]	

Subtotal of deductions for this page [650] to [659] + [661] + [675] [681] 35,666,069
Transfer to Page 15

continued on Page 15

Enersource Hydro Mississauga Inc.

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DOLLARS ONLY

Reconcile net income (loss) for federal income tax purposes with net income (loss) for Ontario purposes if amounts differ

continued from Page 14

Net Income (loss) for federal income tax purposes, per federal Schedule 1	- - - - -	From $\pm$ [600]	28,493,430.
Total of Additions on page 14	- - - - -	From = [640]	35,666,069.
Sub Total of deductions on page 14	- - - - -	From = [681]	35,666,069.

Deduct:

Ontario New Technology Tax Incentive (ONTTI) Gross-up

(Applies only to those corporations whose Ontario allocation is less than 100% in the current taxation year.)

Capital Cost Allowance (Ontario) (CCA) on prescribed qualifying intellectual property deducted in the current taxation year

[662]

ONTTI Gross-up deduction calculation:

Gross-up of CCA

$$\left[\begin{array}{l} \text{From} \\ [662] \end{array} \right] \times \left[\begin{array}{l} 100 \\ \text{From } [30] \end{array} \right] \times \left[\begin{array}{l} 100 \\ 100.0000 \end{array} \right] - \text{From } [662] = [663]$$

Ontario Allocation

Workplace Child Care Tax Incentive (WCCT)

(Applies to eligible expenditures incurred prior to January 1, 2005.)

$$\text{Qualifying expenditures: } [665] \times 30\% \times \left[\begin{array}{l} 100 \\ \text{From } [30] \end{array} \right] \times \left[\begin{array}{l} 100 \\ 100.0000 \end{array} \right] = [666]$$

Ontario allocation

Workplace Accessibility Tax Incentive (WATI)

(Applies to eligible expenditures incurred prior to January 1, 2005.)

$$\text{Qualifying expenditures: } [667] \times 100\% \times \left[\begin{array}{l} 100 \\ \text{From } [30] \end{array} \right] \times \left[\begin{array}{l} 100 \\ 100.0000 \end{array} \right] = [668]$$

Ontario allocation

Number of Employees accommodated

[669]

Ontario School Bus Safety Tax Incentive (OSBSTI)

(Applies to the eligible acquisition of school buses purchased after May 4, 1999 and before January 1, 2006.) (Refer to Guide)

$$\text{Qualifying expenditures: } [670] \times 30\% \times \left[\begin{array}{l} 100 \\ \text{From } [30] \end{array} \right] \times \left[\begin{array}{l} 100 \\ 100.0000 \end{array} \right] = [671]$$

Ontario allocation

Educational Technology Tax Incentive (ETTI)

(Applies to eligible expenditures incurred prior to January 1, 2005.)

$$\text{Qualifying expenditures: } [672] \times 15\% \times \left[\begin{array}{l} 100 \\ \text{From } [30] \end{array} \right] \times \left[\begin{array}{l} 100 \\ 100.0000 \end{array} \right] = [673]$$

Ontario allocation

Ontario allowable business investment loss

+ [678]

Ontario Scientific Research Expenses claimed in year in [477] from Ont. CT23 Schedule 161

+ [679]

Amount added to income federally for an amount that was negative on federal form T661, line 454 or 455 (if filed after June 30, 2003)

+ [677]

Total of other deductions allowed by Ontario (Attach schedule)

+ [664]

$$\text{Total of Deductions } [681] + [663] + [666] + [668] + [671] + [673] + [678] + [679] + [677] + [664] = 35,666,069. \rightarrow [680] \quad 35,666,069.$$

$$\text{Net income (loss) for Ontario Purposes } [600] + [640] - [680] = [690] \quad 28,493,430.$$

Transfer to Page 4

Continuity of Losses Carried Forward

DOLLARS ONLY

	Non-Capital Losses (1)	Total Capital Losses	Farm Losses	Restricted Farm Losses	Listed Personal Property Losses	Limited Partnership Losses (6)
Balance at Beginning of Year	700 (2)	710 (2)	720 (2)	730	740	750
Add:						
Current year's losses (7)	701	711	721	731	741	751
Losses from predecessor corporations (3)	702	712	722	732		752
Subtotal	703	713	723	733	743	753
Subtract:						
Utilized during the year to reduce taxable income	704 (2)	715 (2) (4)	724 (2)	734 (2) (4)	744 (4)	754 (4)
Expired during the year	705		725	735	745	
Carried back to prior years to reduce taxable income (5)	706 (2) to Page 17	716 (2) to Page 17	726 (2) to Page 17	736 (2) to Page 17	746	
Subtotal	707	717	727	737	747	757
Balance at End of Year	709 (8)	719	729	739	749	759

Analysis of Balance at End of Year by Year of Origin

Year of Origin (oldest year first) year month day	Non-Capital Losses	Non-Capital Losses of Predecessor Corporations	Total Capital Losses from Listed Personal Property only	Farm Losses	Restricted Farm Losses
800 9th preceding taxation year 1998-09-30	817 (9)	860 (9)		850	870
801 8th preceding taxation year 1999-09-30	818 (9)	861 (9)		851	871
802 7th preceding taxation year 2000-09-30	819 (9)	862 (9)		852	872
803 6th preceding taxation year 2001-09-30	820	830	840	853	873
804 5th preceding taxation year 2001-12-31	821	831	841	854	874
805 4th preceding taxation year 2002-12-31	822	832	842	855	875
806 3rd preceding taxation year 2003-12-31	823	833	843	856	876
807 2nd preceding taxation year 2004-12-31	824	834	844	857	877
808 1st preceding taxation year 2005-12-31	825	835	845	858	878
809 Current taxation year 2006-12-31	826	836	846	859	879
Total	829	839	849	869	889

Notes:

(1) Non-capital losses include allowable business investment losses, fed.s.111(8)(b), as made applicable by s.34.

(2) Where acquisition of control of the corporation has occurred, the utilization of losses can be restricted. See fed.s.111(4) through 111(5.5), as made applicable by s.34.

(3) Includes losses on amalgamation (fed.s.87(2.1) and s.87(2.11)) and/or wind-up (fed.s.88(1.1) and 88(1.2)), as made applicable by s.34.

(4) To the extent of applicable gains/income/at-risk amount only.

(5) Generally a three year carry-back applies. See fed.s.111(1) and fed.s.41(2)(b), as made applicable by s.34.

(6) Where a limited partner has limited partnership losses, attach loss calculations for each partnership.

(7) Include amount from 11 If taxable income is adjusted to claim unused foreign tax credit for federal purposes.

(8) Amount in 709 must equal total of 829 + 839.

(9) Include non-capital losses incurred in taxation years ending after March 22, 2004.

Energsource Hydro Mississauga Inc.

1800247

2006-12-31

DOLLARS ONLY

Request for Loss Carry-Back (s.80(16))

Applies to corporations requesting a reassessment of the return of one or more previous taxation years under s.80(16) with respect to one or more types of losses carried back.

- If, after applying a loss carry-back to one or more previous years, there is a balance of loss available to carry forward to a future year, it is the corporation's responsibility to claim such a balance for those years following the year of loss within the limitations of fed.s.111, as made applicable by s.34.
- Where control of a corporation has been acquired by a person or group of persons, certain restrictions apply to the carry-forward and carry-back provisions of losses under fed.s.111(4) through 111(5.5), as made applicable by s.34.
- Refunds arising from the loss carry-back adjustment may be applied by the Minister of Finance to amounts owing under any Act administered by the Ministry of Finance.

- Any late filing penalty applicable to the return for which the loss is being applied will not be reduced by the loss carry-back.
- The application of a loss carry-back will be available for interest calculation purposes on the day that is the latest of the following:
 - 1) the first day of the taxation year after the loss year,
 - 2) the day on which the corporation's return for the loss year is delivered to the Minister, or
 - 3) the day on which the Minister receives a request in writing from the corporation to reassess the particular taxation year to take into account the deduction of the loss.
- If a loss is being carried back to a predecessor corporation, enter the predecessor corporation's account number and taxation year end in the spaces provided under Application of Losses below.

Application of Losses

Total amount of loss

Deduct: Loss to be carried back to preceding taxation years and applied to reduce taxable income

	Predecessor Ontario Corporation's Tax Account No. (MOF)	Taxation Year Ending year month day
i) 3 rd preceding	901	2003-12-31
ii) 2 nd preceding	902	2004-12-31
iii) 1 st preceding	903	2005-12-31
Total loss to be carried back		

Non-Capital Losses	Total Capital Losses	Farm Losses	Restricted Farm Losses
910	920	930	940
911	921	931	941
912	922	932	942
913	923	933	943
From 706	From 716	From 726	From 736
919	929	939	949

Balance of loss available for carry-forward

Summary

Income Tax	- - - - -	+ From 230 or 320	3,953,792
Corporate Minimum Tax	- - - - -	+ From 280	
Capital Tax	- - - - -	+ From 550	1,511,876
Premium Tax	- - - - -	+ From 590	
Total Tax Payable	- - - - -	= 950	5,465,668
Subtract: Payments	- - - - -	- 960	5,461,699
Capital Gains Refund (s.48)	- - - - -	- 965	
Qualifying Environmental Trust Tax Credit (Refer to Guide)	- - - - -	- 985	
Specified Tax Credits (Refer to Guide)	- - - - -	- 955	
Other, specify	- - - - -	-	
Balance	- - - - -	= 970	3,969
If payment due	- - - - -	Enclosed * 990	3,969
If overpayment: Refund (Refer to Guide)	- - - - -	= 975	
Apply to	year month day	980	

(Includes credit interest)

* Make your cheque (drawn on a Canadian financial institution) or a money order in Canadian funds, payable to the Minister of Finance and print your Ontario Corporation's Tax Account No. (MOF) on the back of cheque or money order. (Refer to Guide for other payment methods.)

Certification

I am an authorized signing officer of the corporation. I certify that this CT23 return, including all schedules and statements filed with or as part of this CT23 return, has been examined by me and is a true, correct and complete return and that the information is in agreement with the books and records of the corporation. I further certify that the financial statements accurately reflect the financial position and operating results of the corporation as required under section 75 of the *Corporations Tax Act*. The method of computing income for this taxation year is consistent with that of the previous year, except as specifically disclosed in a statement attached.

Name (please print)

Title

Full Residence Address

Signature

Date

Note: Section 76 of the *Corporations Tax Act* provides penalties for making false or misleading statements or omissions.

Attached Schedule with Total

Other reserves not allowed as deductions for income tax purposes (Attach schedule) (Int.B. 3012R)

Title Other reserves not allowed as deductions for income tax purposes (Attach

Description

		Amount
Employee Retirement and post-retirement benefits		2,583,000 00
Book deductions greater than tax deductions		13,455,859 00
	Total	16,038,859 00

Corporate Minimum Tax (CMT)
CT23 Schedule 101

Page 1 of 3

Corporation's Legal Name Enersource Hydro Mississauga Inc.	Ontario Corporations Tax Account No. (MOF) 1800247	Taxation Year End 2006-12-31

Part 1: Calculation of CMT Base

Banks – Net income/loss as per report accepted by Superintendent of Financial Institutions (SFI) under the Bank Act (Canada), adjusted so consolidation/equity methods are not used.

Life Insurance corporations – Net income/loss before Special Additional Tax as determined under s.57.1(2)(c) or (d)

Net Income/Loss (unconsolidated, determined in accordance with GAAP) ± [2100] 13,301,000.

Subtract (to the extent reflected in net income/loss):

Provision for recovery of income taxes / benefit of current income taxes + [2101]
 Provision for deferred income taxes (credits) / benefit of future income taxes + [2102]
 Equity income from corporations + [2103]
 Share of partnership(s)/joint venture(s) income + [2104]
 Dividends received/receivable deductible under fed.s.112 + [2105]
 Dividends received/receivable deductible under fed.s.113 + [2106]
 Dividends received/receivable deductible under fed.s.83(2) + [2107]
 Dividends received/receivable deductible under fed.s.138(6) + [2108]
 Federal Part VI.1 tax paid on dividends declared and paid, under fed.s.191.1(1) x 3 + [2109]

Subtotal = [2110]

Add (to extent reflected in net income/loss):

Provision for current taxes / cost of current income taxes + [2111] 10,119,000.
 Provision for deferred income taxes (debits) / cost of future income taxes + [2112]
 Equity losses from corporations + [2113]
 Share of partnership(s)/joint venture(s) losses + [2114]
 Dividends that have been deducted to arrive at net income per Financial Statements s.57.4(1.1) (excluding dividends under fed.s.137(4.1)) + [2115]

Subtotal = 10,119,000. + [2116] 10,119,000.

Add/Subtract:

Amounts relating to s.57.9 election/regulations for disposals etc. of property for current/prior years

** Fed.s.85 + [2117] or - [2118]
 ** Fed.s.85.1 + [2119] or - [2120]
 ** Fed.s.97 + [2121] or - [2122]

** Amounts relating to amalgamations (fed.s.87) as prescribed in regulations for current/prior years + [2123] or - [2124]

** Amounts relating to wind-ups (fed.s.88) as prescribed in regulations for current/prior years + [2125] or - [2126]

** Amounts relating to s.57.10 election/regulations for replacement re fed.s.13(4), 14(6) and 44 for current/prior years + [2127] or - [2128]

Interest allowable under ss.20(1)(c) or (d) of ITA to the extent not otherwise deducted in determining CMT adjusted net income - [2150]

Capital gains on eligible donations of publicly-listed securities and ecologically sensitive land made after May 1, 2006 (to the extent reflected in net income/loss) - [2155]

Subtotal (Additions) = + [2129]

Subtotal (Subtractions) = - [2130]

** Other adjustments ± [2131]

Subtotal ± [2100] - [2110] + [2116] + [2129] - [2130] ± [2131] = [2132] 23,420,000.

** Share of partnership(s)/joint venture(s) adjusted net income/loss ± [2133]

Adjusted net income (loss) (if loss, transfer to [2202] in Part 2: Continuity of CMT Losses Carried Forward.) = [2134] 23,420,000.

Deduct: * CMT losses: pre-1994 Loss + From [2210]

* CMT losses: other eligible losses + [2211]

Subtotal = - [2135]

* CMT losses applied cannot exceed adjusted net income or increase a loss

** Retain calculations. Do not submit with this schedule.

CMT Base = [2136] 23,420,000.

Transfer to CMT Base on Page 8 of the CT23 or Page 6 of the CT8

CT23 Schedule 101

Corporation's Legal Name Enersource Hydro Mississauga Inc.	Ontario Corporations Tax Account No. (MOF) 1800247	Taxation Year End 2006-12-31

Part 2: Continuity of CMT Losses Carried Forward

Balance at Beginning of year NOTES (1), (2) + 2201 []

Add: Current year's losses + 2202 []

Losses from predecessor corporations on amalgamation NOTE (3) + 2203 []

Losses from predecessor corporations on wind-up NOTE (3) + 2204 []

Amalgamation (X) 2205 ☐ Yes Wind-up (X) 2206 ☐ Yes

Subtotal = [] + 2207 []

Adjustments (attach schedule) ± 2208 []

CMT losses available 2201 + 2207 ± 2208 = 2209 []

Subtract: Pre-1994 loss utilized during the year to reduce adjusted net income + 2210 []

Other eligible losses utilized during the year to reduce adjusted net income NOTE (4) + 2211 []

Losses expired during the year + 2212 []

Subtotal = [] - 2213 []

Balances at End of Year NOTE (5) 2209 - 2213 = 2214 []

Notes:

- (1) Pre-1994 CMT loss (see s.57.1(1)) should be included in the balance at beginning of the year. Attach schedule showing computation of pre-1994 CMT loss.
- (2) Where acquisition of control of the corporation has occurred, the utilization of CMT losses can be restricted. (see s.57.5(3) and s.57.5(7))
- (3) Include and indicate whether CMT losses are a result of an amalgamation to which fed.s.87 applies and/or a wind-up to which fed.s.88(1) applies. (see s.57.5(8) and s.57.5(9))
- (4) CMT losses must be used to the extent of the lesser of the adjusted net income 2134 and CMT losses available 2209.
- (5) Amount in 2214 must equal sum of 2270 + 2290.

Part 3: Analysis of CMT Losses Year End Balance by Year of Origin

For a pre-1994 loss, use the date of the last taxation year end before your corporation's first taxation year commencing after 1993.

	Year of Origin (oldest year first) year month day	CMT Losses of Corporation	CMT Losses of Predecessor Corporations
2240	9th preceding taxation year 1998-09-30	2260	2280
2241	8th preceding taxation year 1999-09-30	2261	2281
2242	7th preceding taxation year 2000-09-30	2262	2282
2243	6th preceding taxation year 2001-09-30	2263	2283
2244	5th preceding taxation year 2001-12-31	2264	2284
2245	4th preceding taxation year 2002-12-31	2265	2285
2246	3rd preceding taxation year 2003-12-31	2266	2286
2247	2nd preceding taxation year 2004-12-31	2267	2287
2248	1st preceding taxation year 2005-12-31	2268	2288
2249	Current taxation year 2006-12-31	2269	2289
Totals		2270	2290

The sum of amounts 2270 + 2290
must equal amount in 2214.

Corporate Minimum Tax (CMT)

CT23 Schedule 101

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Corporation's Legal Name Enersource Hydro Mississauga Inc.	Ontario Corporations Tax Account No. (MOF) 1800247	Taxation Year End 2006-12-31

Part 4: Continuity of CMT Credit Carryovers

Balance at Beginning of year NOTE (1) + 2301 []

Add: Current year's CMT Credit (280 on page 8 of the CT23
or 347 on page 6 of the CT8. If negative, enter NIL) + From 280 or 347 []

Gross Special Additional Tax NOTE (2) 312 on page 5 of CT8.
(Life Insurance corporations only.
Others enter NIL.) + From 312 []

Subtract Income Tax
(190 on page 6 of the CT23 or
page 4 of the CT8) - From 190 []

Subtotal (If negative, enter NIL) ... = [] - 2305 []

Current year's CMT credit (If negative, enter NIL) 280 or 347 - 2305 ... = [] + 2310 []

CMT Credit Carryovers from predecessor corporations NOTE (3) + 2325 []

Amalgamation (X) 2315 [] Yes Wind-up (X) 2320 [] Yes

Subtotal 2301 + 2310 + 2325 = 2330 []

Adjustments (Attach schedule) ± 2332 []

CMT Credit Carryover available 2330 ± 2332 = 2333 []

Transfer to Page 8 of the CT23 or Page 6 of the CT8

Subtract: CMT Credit utilized during the year to reduce income tax
(310 on page 8 of the CT23 or 351 on page 6 of the CT8.) + From 310 or 351 []

CMT Credit expired during the year + 2334 []

Subtotal = [] - 2335 []

Balance at End of Year NOTE (4) 2333 - 2335 = 2336 []

Notes:

- (1) Where acquisition of control of the corporation has occurred, the utilization of CMT credits can be restricted. (see s.43.1(5))
- (2) The CMT credit of life insurance corporations can be restricted (see s.43.1(3)(b)).
- (3) Include and indicate whether CMT credits are a result of an amalgamation to which fed.s.87 applies and/or a wind-up to which fed.s.88(1) applies. (see s.43.1(4))
- (4) Amount in 2336 must equal sum of 2370 + 2390.

Part 5: Analysis of CMT Credit Carryovers Year End Balance by Year of Origin

	Year of Origin (oldest year first) year month day	CMT Credit Carryovers of Corporation	CMT Credit Carryovers of Predecessor Corporation(s)
2340	9th preceding taxation year 1998-09-30	2360	2380
2341	8th preceding taxation year 1999-09-30	2361	2381
2342	7th preceding taxation year 2000-09-30	2362	2382
2343	6th preceding taxation year 2001-09-30	2363	2383
2344	5th preceding taxation year 2001-12-31	2364	2384
2345	4th preceding taxation year 2002-12-31	2365	2385
2346	3rd preceding taxation year 2003-12-31	2366	2386
2347	2nd preceding taxation year 2004-12-31	2367	2387
2348	1st preceding taxation year 2005-12-31	2368	2388
2349	Current taxation year 2006-12-31	2369	2389
Totals		2370	2390

The sum of amounts 2370 + 2390
must equal amount in 2336.

Corporate Minimum Tax (CMT)
CT23 Schedule 101 – Supporting Schedule

Corporation's Legal Name Enersource Hydro Mississauga Inc.	Ontario Corporations Tax Account No. (MOF) 1800247	Taxation Year End 2006-12-31

CMT Losses Carried Forward Workchart

(i) Continuity of Pre-1994 CMT Losses

	Corporation's Pre-1994 Loss	Predecessors' Pre-1994 Loss Amalgamation	Wind-Up
Date of the last tax year end before the corp's 1st tax year commencing after 1993			
Pre-1994 Loss (per schedule)			
Less: Claimed in prior taxation years commencing after 1993			
Pre-1994 Loss available for the current year			
Less: Deducted in the current year			
(max. = adj. net income for the year)			
Expired after 10 years			
Pre-1994 Loss Carryforward			

(ii) Continuity of Other Eligible CMT Losses – Filing Corporation
(for losses occurring in tax years commencing after 1993)

	Year of Origin YYYY/MM/DD	Opening Balance	Adjustment	Deduction	Expired	Closing Balance
10th Prior Year	1997-09-30					
9th Prior Year	1998-09-30					
8th Prior Year	1999-09-30					
7th Prior Year	2000-09-30					
6th Prior Year	2001-09-30					
5th Prior Year	2001-12-31					
4th Prior Year	2002-12-31					
3rd Prior Year	2003-12-31					
2nd Prior Year	2004-12-31					
1st Prior Year	2005-12-31					
Total						

Predecessor Corporations Only – Amalgamation

Indicate the amounts of eligible CMT losses from predecessor corporations. Do not include these amounts in the 'opening balance' of the Filing Corporation.

Year of Origin YYYY/MM/DD	Opening Balance	Add	Adjustment	Deduction	Expired	Closing Balance
1997-09-30						
1998-09-30						
1999-09-30						
2000-09-30						
2001-09-30						
2001-12-31						
2002-12-31						
2003-12-31						
2004-12-31						
2005-12-31						
Total						

Corporate Minimum Tax (CMT)
CT23 Schedule 101 – Supporting Schedule

Corporation's Legal Name Enersource Hydro Mississauga Inc.	Ontario Corporations Tax Account No. (MOF) 1800247	Taxation Year End 2006-12-31

CMT Losses Carried Forward Workchart (continued)

Predecessor Corporations Only – Wind-Up

Indicate the amounts of eligible CMT losses from predecessor corporations. Do not include these amounts in the 'opening balance' of the Filing Corporation.

Year of Origin YYYY/MM/DD	Opening Balance	Add	Adjustment	Deduction	Expired	Closing Balance
1997-09-30						
1998-09-30						
1999-09-30						
2000-09-30						
2001-09-30						
2001-12-31						
2002-12-31						
2003-12-31						
2004-12-31						
2005-12-31						
Total						

Corporate Minimum Tax (CMT)
CT23 Schedule 101 – Supporting Schedule

Corporation's Legal Name Enersource Hydro Mississauga Inc.	Ontario Corporations Tax Account No. (MOF) 1800247	Taxation Year End 2006-12-31

CMT Credit Carryovers Workchart

- Filing Corporation

	Year of Origin YYYY/MM/DD	Opening Balance	Adjustment	Deduction	Expired	Closing Balance
10th Prior Year	1997-09-30					
9th Prior Year	1998-09-30					
8th Prior Year	1999-09-30					
7th Prior Year	2000-09-30					
6th Prior Year	2001-09-30					
5th Prior Year	2001-12-31					
4th Prior Year	2002-12-31					
3rd Prior Year	2003-12-31					
2nd Prior Year	2004-12-31					
1st Prior Year	2005-12-31					
	Total					

Predecessor Corporations Only – Amalgamation

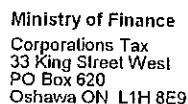
Indicate the amounts of CMT credit carryovers from predecessor corporations. Do not include these amounts in the 'opening balance' of the Filing Corporation.

Year of Origin YYYY/MM/DD	Opening Balance	Add	Adjustment	Deduction	Expired	Closing Balance
1997-09-30						
1998-09-30						
1999-09-30						
2000-09-30						
2001-09-30						
2001-12-31						
2002-12-31						
2003-12-31						
2004-12-31						
2005-12-31						
	Total					

Predecessor Corporations Only – Wind-Up

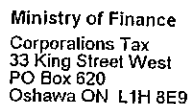
Indicate the amounts of CMT credit carryovers from predecessor corporations. Do not include these amounts in the 'opening balance' of the Filing Corporation.

Year of Origin YYYY/MM/DD	Opening Balance	Add	Adjustment	Deduction	Expired	Closing Balance
1997-09-30						
1998-09-30						
1999-09-30						
2000-09-30						
2001-09-30						
2001-12-31						
2002-12-31						
2003-12-31						
2004-12-31						
2005-12-31						
	Total					



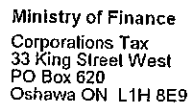
Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
Enersource Hydro Mississauga Inc.	1800247	2006-12-31

CORPORATE TAXPREP - 2007 V.1 Page 1 of 1



Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
Enersource Hydro Mississauga Inc.	1800247	2006-12-31

CORPORATE TAXPREP - 2007 V.1 Page 1 of 1



Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
Enersource Hydro Mississauga Inc.	1800247	2006-12-31

(includes accounts payable to related parties outstanding at the taxation year end for 120 days or more, and accounts payable to non-related parties outstanding for 365 days or more at the taxation year end)

Total	
Transfer to 353 of the CT23	= 25,818,216

Corporation's Legal Name Enersource Hydro Mississauga Inc.		Ontario Corporations Tax Account No. (MOF) 1800247		Taxation Year End 2006-12-31

Is the corporation electing under regulation 1101(5q)? 1 ☐ Yes 2 ☒ No

1 Class number	2 Ontario undepreciated capital cost at the beginning of the year (undepreciated capital cost at the end of the prior year's CCA schedule)	3 Cost of acquisitions during the year (new property must be available for use) See note 1 below	4 Net adjustments (show negative amounts in brackets)	5 Proceeds of dispositions during the year (amount not to exceed the capital cost)	6 Ontario undepreciated capital cost (column 2 plus column 3 or minus column 4 minus column 5)	7 50% rule (1/2 of the amount, if any, by which the net cost of acquisitions exceeds column 5) See note 2 below	8 Reduced undepreciated capital cost (column 6 minus column 7)	9 CCA rate %	10 Recapture of capital cost allowance	11 Terminal loss	12 Ontario capital cost allowance (column 8 multiplied by column 9, or a lower amount)	13 Ontario undepreciated capital cost at the end of the year (column 6 minus column 12)
1	378,561,861	510,144		0	379,072,005	255,072	378,816,933	4	0	0	15,152,677	363,919,328
2	47,841,411			0	47,841,411		47,841,411	6	0	0	2,870,485	44,970,926
8	9,596,179	1,277,051		0	10,873,230	638,526	10,234,704	20	0	0	2,046,941	8,826,289
10	8,770,000	1,523,210		191,232	10,101,978	685,989	9,435,989	30	0	0	2,830,797	7,271,181
98	6,588,925			0	6,588,925		6,588,925	0	0	0		6,588,925
12	472,272	1,965,292		0	2,437,564	982,646	1,454,918	100	0	0	1,454,918	982,646
3	2,774,633			0	2,774,633		2,774,633	5	0	0	138,732	2,635,901
45	863,230	1,519,942		300	2,382,872	759,821	1,623,051	45	0	0	730,373	1,652,499
10.1	20,527			N/A	20,527		20,527	30	N/A	N/A	6,158	14,369
See schedule	18,331,289	27,930,424			46,261,713	13,965,212	32,296,501				2,646,837	43,614,876
Totals	473,820,327	34,726,063		191,532	508,354,858	17,267,266	491,087,592				27,877,918	480,476,940

Enter in boxes **650** **550** **650** on the CT23.

Note 1. Include any property acquired in previous years that has now become available for use. This property would have been previously excluded from column 3. List separately any acquisitions that are not subject to the 50% rule. See Regulation 1100(2) and (2.2) of the *Income Tax Act* (Canada).

Note 2. The net cost of acquisitions is the cost of acquisitions plus or minus certain adjustments from column 4.

Note 3. If the taxation year is shorter than 365 days, prorate the CCA claim.

Note 4. Ontario recapture should be included in net income after deducting the federal recapture and the Ontario terminal loss is deducted from net income after including the federal terminal loss.

Ontario Capital Cost Allowance Schedule 8

Corporation's Legal Name		Ontario Corporations Tax Account No. (MOF)		Taxation Year End
Enersource Hydro Mississauga Inc.		1800247		2006-12-31

1 Class number	2 Ontario undepreciated capital cost at the beginning of the year (undepreciated capital cost at the end of the prior year's CCA schedule)	3 Cost of acquisitions during the year (new property must be available for use) See note 1 below	4 Net adjustments (show negative amounts in brackets)	5 Proceeds of dispositions during the year (amount not to exceed the capital cost)	6 Ontario undepreciated capital cost (column 2 plus column 3 or minus column 4 minus column 5)	7 50% rule (1/2 of the amount, if any, by which the net cost of acquisitions exceeds column 5) See note 2 below	8 Reduced undepreciated capital cost (column 6 minus column 7)	9 CCA rate %	10 Recapture of capital cost allowance	11 Terminal loss	12 Ontario capital cost allowance (column 8 multiplied by column 9, or a lower amount)	13 Ontario undepreciated capital cost at the end of the year (column 6 minus column 12)
10.1	20,527			N/A	20,527		20,527	30	N/A	N/A	6,158	14,369
10.1	20,527			N/A	20,527		20,527	30	N/A	N/A	6,158	14,369
10.1	20,527			N/A	20,527		20,527	30	N/A	N/A	6,158	14,369
10.1	20,527			N/A	20,527		20,527	30	N/A	N/A	6,158	14,369
10.1	20,527			N/A	20,527		20,527	30	N/A	N/A	6,158	14,369
10.1	20,527			N/A	20,527		20,527	30	N/A	N/A	6,158	14,369
10.1	29,325			N/A	29,325		29,325	30	N/A	N/A	8,798	20,527
47	18,061,502	27,896,224		0	45,957,726	13,948,112	32,009,614	8	0	0	2,560,769	43,396,957
10.1	29,325			N/A	29,325		29,325	30	N/A	N/A	8,798	20,527
10.1	29,325			N/A	29,325		29,325	30	N/A	N/A	8,798	20,527
10.1	29,325			N/A	29,325		29,325	30	N/A	N/A	8,798	20,527
10.1	29,325			N/A	29,325		29,325	30	N/A	N/A	8,798	20,527
10.1	34,200	34,200		N/A	34,200	17,100	17,100	30	N/A	N/A	5,130	29,070
Totals	18,331,289	27,930,424			46,261,713	13,965,212	32,296,501				2,646,837	43,614,876



Ministry of Finance
Corporations Tax
33 King Street West
PO Box 620
Oshawa ON L1H 8E9

Ontario Cumulative Eligible Capital Deduction Schedule 10 Page 1 of 2

For taxation years 2002 and later

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
Enersource Hydro Mississauga Inc.	1800247	2006-12-31

- For use by a corporation that has eligible capital property.
- A separate cumulative eligible capital account must be kept for each business.

Part 1 – Calculation of current year deduction and carry-forward

Ontario Cumulative eligible capital – balance at end of preceding taxation year (if negative, enter zero) = + 22,401,090 A

Add: Cost of eligible capital property acquired during the taxation year + ... B

Other adjustments + ... C

B + C = ... x 3 / 4 = ... D

Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an eligible capital property to the corporation after December 20, 2002 x 1 / 2 = - E

D minus E (if negative, enter zero) = ... F

Amount transferred on amalgamation or wind-up of subsidiary + ... G

Subtotal A + F + G = 22,401,090 H

Deduct: Ontario proceeds of sales (less outlays and expenses not otherwise deductible) from the disposition of all eligible capital property during the taxation year + ... I

The gross amount of a reduction in respect of a forgiven debt obligation as provided for in subsection 80(7) of the Income Tax Act (Canada) + ... J

Other adjustments + ... K

I + J + K = ... x 3 / 4 = - L

Ontario cumulative eligible capital balance H minus L = 22,401,090 M

If M is negative, enter zero at line Q and proceed to Part 2, page 2.

Cumulative eligible capital for a property no longer owned after ceasing to carry on that business N

From M 22,401,090

From N -

Current year deduction M minus N = 22,401,090 x 7 % = + 1,568,076 O

N + O = 1,568,076 P

Note: The maximum current year deduction is 7%. Any amount up to the maximum deduction of 7% may be claimed.
For taxation years starting after December 21, 2000, the deduction may not exceed the maximum amount prorated for the number of days in the taxation year divided by 365 or 366 days.

Enter amount in box 651 of the CT23

Ontario cumulative eligible capital - closing balance M minus P (if negative, enter zero) = 20,833,014 Q

See page 2 - Part 2

Ontario Cumulative Eligible Capital Deduction
Schedule 10 Page 2 of 2

Corporation's Legal Name Enersource Hydro Mississauga Inc.	Ontario Corporations Tax Account No. (MOF) 1800247	Taxation Year End 2006-12-31

Part 2 – Amount to be included in income arising from disposition

Complete this part only if the amount at line M is negative.

Amount from line M above. *Show this as a positive amount; not negative.*

Total cumulative eligible capital deductions from income for taxation years beginning after June 30, 1988 **R**

..... + ... **1**

Total of all amounts which reduced cumulative eligible capital in the current or prior years under subsection 80(7) of the ITA + ... **2**

Total of cumulative eligible capital deductions claimed for taxation years beginning before July 1, 1988 + ... **3**

Negative balances in the cumulative eligible capital account that were included in income for taxation years beginning before July 1, 1988 - **4**

Deduct line 4 from line 3 (if negative, enter zero) = ... **5**

Total lines 1 + 2 + 5 = ... **6**

Amounts included in income under paragraph 14(1)(b), as that paragraph applied to taxation years ending after June 30, 1988 and before February 28, 2000, to the extent that it is for an amount described at line 1 **7**

Amounts at Line Z from Ontario Schedule 10 of previous taxation years ending after February 27, 2000 (This will be Line T in earlier versions of this schedule.) + ... **8**

Total lines 7 + 8 = ... **9**

Deduct line 9 from line 6 (if negative, enter zero) = ... **S**

R minus S (if negative, enter zero) = ... **T**

From Line 5 x 1 / 2 = ... **U**

T minus U (if negative, enter zero) = ... **V**

From V x 2 / 3 = ... **W**

Lesser of R and S = + ... **Z**

Amount to be included in income W + Z = ...



Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
Enersource Hydro Mississauga Inc.	1800247	2006-12-31

Description of property	Ontario balance at the beginning of the year \$	Transfer on amalgamation or wind-up of subsidiary \$	Add	Deduct	Ontario balance at the end of the year \$
1					
Totals	A	B			C

Description	Ontario balance at the beginning of the year \$	Transfer on amalgamation or wind-up of subsidiary \$	Add	Deduct	Ontario balance at the end of the year \$
Reserve for doubtful debts					
Reserve for undelivered goods and services not rendered					
Reserve for prepaid rent					
Reserve for December 31, 1995 income					
Reserve for refundable containers					
Reserve for unpaid amounts					
Other tax reserves					
Totals	D	E			F

Reserve	Ontario opening balance	Transfers	Ontario additions	Ontario deductions	Other adjustments	Ontario closing balance
Retirees Benefit Liability	2,140,123		442,877			2,583,000
Provision for Bad Debt			1,496,952			1,496,952
Reserves from Part 2						
Totals	2,140,123		1,939,829			4,079,952

Enter in box 653 of the CT23

Enter in box 606 of the CT23

Taxable Capital of Associated Corporations

(Applicable to an associated group that has a permanent establishment in Canada)

Schedule CT21

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
Enersource Hydro Mississauga Inc.	1800247	2006-12-31

This schedule must be completed in determining the aggregate taxable capital of an associated group and/or partnership that has a permanent establishment (PE) in Canada.

Name of Associated Corporation (Must have a PE in Canada)	Corporations Tax Account No. (MOF) (if applicable)	Taxation Year End	Taxable Capital
First Source Energy Corporation	1800361	2006-12-31	+ 459,261
Enersource Telecom Inc.	1800250	2006-12-31	+ 14,492,400
Enersource Hydro Mississauga Services Inc.	1800248	2006-12-31	+ 7,361,271
Enersource Corporation	1800246	2006-12-31	+ 5,867,350
			+
			+
			+
			+
			+
			+
			+
			+
			+
			+
			+
			+
			+
			+
			+
			+
			+
			+
			+
Aggregate of taxable capital			= 28,180,282

Transfer to box **540** of the CT23



Corporation's Legal Name Enersource Hydro Mississauga Inc.	Ontario Corporations Tax Account No. (MOF) 1800247	Taxation Year End 2006-12-31

Instructions for completing the CETC Claim Form

- Enter the relevant details for each qualifying work placement, including the amount of tax credit.
- Your total tax credit for the taxation year is equal to the sum of the tax credits for each qualifying work placement.
- Enter the total tax credit claimed on line 192, page 7 of the CT23 Long, or page 4 of the CT23 Short, or page 4 of the CT8.
 - The maximum amount of credit that can be claimed in respect of each work placement is \$1,000.
- Ensure you have the following documentation (Do not include with the form or tax return.):
 - a letter of certification from the Ontario college, university other post-secondary institution, containing information as specified by the Minister, stating that the student is enrolled in a qualifying education program; or
 - a voucher for leading-edge technology programs, other than an apprenticeship, stating that the educational program meets the definition of a qualifying program in leading-edge technology and that the work performed by that student during the work placement is in a related field.
- The credit is considered government assistance and is therefore to be included in income in the year the credit is claimed.

Summary of Co-operative Education Tax Credit Claimed

Complete a separate entry for each student work placement which ended during the corporation's taxation year. The tax credit is for co-op work placements and leading-edge technology work placements. A work placement is generally considered to be a full-time work assignment for up to 4 months in duration.

Example: If a corporation, with a December 31, 2001 taxation year end, hires an eligible student from September 1, 2001 until April 30, 2002, this would be considered 2 work placements. The first work placement is September 1, 2001 to December 31, 2001 and would be claimed in the 2001 taxation year. The second placement is January 1, 2002 to April 30, 2002 and must be claimed in the 2002 taxation year.

Qualifying Work Placements

Name of University/ College and Education Program	Name of Student	Social Insurance No. of Student	Work Placement Start and End Dates	Eligible Costs of Placement (ECP)	* Credit Claimed (See notes below) (max. \$1,000 per work placement)
			year month day		
Sheridan Marketing	Kamal Rehal		From 2006-09-05	16,717	1,000
			To 2006-12-06		
Sheridan Marketing	Jason Azevedo		From 2006-09-05	7,458	1,000
			To 2006-12-20		
See schedule			From	46,737	6,000
			To		
If insufficient space, attach schedule				5774	5798
Totals				70,912	8,000

If insufficient space, attach schedule

Transfer to 192 on Page 7 of the CT23 Long
or Page 4 of the CT23 Short,
or Page 4 of the CT8

Note: Enter corporation's salaries & wages paid in the preceding taxation year A \$ 37,129 •

If A is \$600,000 or greater use 10%. If A is \$400,000 or less use 15%.

If A is over \$400,000 but less than \$600,000 use the following formula to calculate the rate:

Rate = .15 - [.05 (From A 37,129 • - \$400,000) ÷ \$200,000]

Indicate rate used: 15.0000%. *Credit claimed equals ECP multiplied by rate.

Cooperative Education Tax Credit (CETC)
CT23 Schedule 113

Corporation's Legal Name Enersource Hydro Mississauga Inc.	Ontario Corporations Tax Account No. (MOF) 1800247	Taxation Year End 2006-12-31

Qualifying Work Placements

Name of University/ College and Education Program	Name of Student	Social Insurance No. of Student	Work Placement Start and End Dates			Eligible Costs of Placement (ECP)	Credit Claimed (max. \$1,000 per work placement)
			year	month	day		
Sheridan Marketing	Marco Aulutta		From	2006-09-05		7,410	1,000
			To	2006-12-20			
Sheridan Marketing	Umber Siddiqui		From	2006-09-05		7,264	1,000
			To	2006-12-20			
Sheridan Marketing	Justin Warren		From	2006-09-05		9,355	1,000
			To	2006-12-20			
Sheridan Marketing	Justin Warren		From	2006-01-09		7,411	1,000
			To	2006-04-28			
Mohawk Electrotechnology	Ali Sharif		From	2006-08-30		7,792	1,000
			To	2006-12-20			
Sheridan Marketing	Jordan Beardall		From	2006-09-05		7,505	1,000
			To	2006-12-22			
Totals						46,737	6,000

Financial Statements of

**ENERSOURCE HYDRO
MISSISSAUGA INC.**

Year ended December 31, 2006



KPMG LLP
Chartered Accountants
Yonge Corporate Centre
4100 Yonge Street Suite 200
Toronto ON M2P 2H3
Canada

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Fax (416) 228-7123
Internet www.kpmg.ca

AUDITORS' REPORT TO THE SHAREHOLDER

We have audited the balance sheet of Enersource Hydro Mississauga Inc. as at December 31, 2006 and the statements of income, retained earnings and cash flows for the year then ended. These financial statements are the responsibility of the Corporation's management. Our responsibility is to express an opinion on these financial statements based on our audit.

We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these financial statements present fairly, in all material respects, the financial position of the Corporation as at December 31, 2006 and the results of its operations and its cash flows for the year then ended in accordance with Canadian generally accepted accounting principles.

KPMG LLP

Chartered Accountants

Toronto, Canada

March 2, 2007

ENERSOURCE HYDRO MISSISSAUGA INC.

Balance Sheet
(In thousands of dollars)

December 31, 2006, with comparative figures for 2005

	2006	2005
Assets		
Current assets:		
Cash and cash equivalents	\$ 32,751	\$ 61,275
Accounts receivable	61,185	52,996
Unbilled revenue	51,311	64,478
Due from related party, without interest (note 12)	1,352	53
Inventory	5,394	4,845
Prepaid expenses and deposits	534	550
	152,507	184,197
Capital assets (note 3)	399,445	394,048
Other assets:		
Cash and cash equivalents held for consumer deposits	21,740	22,354
Deferred debt issue costs, net of accumulated amortization of \$2,458 (2005 - \$2,024)	1,878	2,312
Regulatory assets (note 4)	12,179	21,014
	35,797	45,680
	<u>\$ 587,749</u>	<u>\$ 623,925</u>
Liabilities and Shareholder's Equity		
Current liabilities:		
Accounts payable and accrued liabilities	\$ 77,369	\$ 114,318
Payments in lieu of corporate income taxes payable	3,933	6,398
Advance payments	1,704	486
Due to related parties, without interest (note 12)	2,372	1,187
Regulatory liabilities (note 4)	5,283	8,678
	90,661	131,067
Long-term liabilities:		
Bonds payable (note 5)	290,000	290,000
Consumer deposits	21,740	22,354
Employee retirement and post-retirement benefits (note 8)	2,583	2,140
	314,323	314,494
Shareholder's equity:		
Capital stock (note 6)	155,629	155,629
Retained earnings	27,136	22,735
	182,765	178,364
Contingencies (note 9)		
Commitments (note 10)		
	<u>\$ 587,749</u>	<u>\$ 623,925</u>

See accompanying notes to financial statements.

On behalf of the Board:

Director

ENERSOURCE HYDRO MISSISSAUGA INC.

Statement of Income
(In thousands of dollars)

Year ended December 31, 2006, with comparative figures for 2005

	2006	2005
Revenue:		
Energy sales	\$ 557,271	\$ 672,412
Distribution	104,120	95,982
Recovery of regulatory assets	7,144	7,513
Other	2,862	6,455
	671,397	782,362
Operating expenses:		
Energy purchases	557,271	672,412
Operations, maintenance and administration	37,456	35,374
Amortization of capital assets	30,275	29,766
Amortization of regulatory assets	7,144	7,513
	632,146	745,065
Operating income	39,251	37,297
Interest:		
Income	2,764	1,718
Expense	(18,595)	(17,677)
	(15,831)	(15,959)
Income before payments in lieu of corporate income taxes	23,420	21,338
Payments in lieu of corporate income taxes (note 2)	10,119	8,559
Net income	\$ 13,301	\$ 12,779

Statement of Retained Earnings
(In thousands of dollars)

Year ended December 31, 2006, with comparative figures for 2005

	2006	2005
Retained earnings, beginning of year	\$ 22,735	\$ 16,250
Net income	13,301	12,779
Dividends paid (note 6(b))	(8,900)	(6,294)
Retained earnings, end of year	\$ 27,136	\$ 22,735

See accompanying notes to financial statements.

ENERSOURCE HYDRO MISSISSAUGA INC.

Statement of Cash Flows
(In thousands of dollars)

Year ended December 31, 2006, with comparative figures for 2005

	2006	2005
Cash provided by (used in):		
Operating activities:		
Net income	\$ 13,301	\$ 12,779
Items not affecting cash:		
Amortization of debt issue costs	434	434
Amortization of capital assets	30,275	29,766
Amortization of regulatory assets	7,144	7,513
Loss on disposal of capital assets	3	189
Employee retirement and post-retirement benefits	443	91
	51,600	50,772
Change in non-cash operating working capital (note 7)	(37,240)	25,997
	14,360	76,769
Financing activities:		
Consumer deposits	(614)	(5,766)
Dividends paid	(8,900)	(6,294)
	(9,514)	(12,060)
Investing activities:		
Cash and cash equivalents held for consumer deposits	614	5,766
Additions to capital assets	(35,866)	(30,245)
Proceeds on disposal of capital assets	191	86
Decrease (increase) in regulatory assets	1,691	(4,162)
	(33,370)	(28,555)
Increase (decrease) in cash and cash equivalents	(28,524)	36,154
Cash and cash equivalents, beginning of year	61,275	25,121
Cash and cash equivalents, end of year	\$ 32,751	\$ 61,275
Supplemental cash flow information:		
Interest received	\$ 2,714	\$ 1,726
Interest paid	18,241	18,241
Payments in lieu of corporate income taxes paid	14,920	6,116

See accompanying notes to financial statements.

ENERSOURCE HYDRO MISSISSAUGA INC.

Notes to Financial Statements
(In thousands of dollars)

Year ended December 31, 2006

Enersource Hydro Mississauga Inc. (the "Corporation") is the electric distribution utility for residents of the City of Mississauga (the "City").

1. Significant accounting policies:

(a) Basis of accounting:

These financial statements have been prepared by management in accordance with generally accepted accounting principles ("GAAP").

(b) Rate setting:

The Corporation is regulated by the Ontario Energy Board ("OEB") under authority of the Ontario Energy Board Act, 1998. The OEB is charged with the responsibility of approving or setting rates for the transmission and distribution of electricity and the responsibility for ensuring that distribution companies fulfill obligations to connect and service customers.

The OEB has the general power to include or exclude costs, revenue, losses or gains in the rates of a specific period, resulting in the change in the timing of accounting recognition from that which would have applied in an unregulated company. Specifically, the following accounting treatments have been applied:

- (i) Capital and operating costs incurred in respect of the transition to competitive markets have been deferred with amortization to commence at a date that a rate increase is implemented to offset the amortization of the transition costs. In November 2003, the Province of Ontario introduced the Ontario Energy Board Amendment Act (Electricity Pricing) 2003 (the "2003 Act"). The 2003 Act impacts both the distribution and energy rates charged to customers and includes a provision for the recovery of regulatory assets (note 1(k)). As of April 1, 2004, the Corporation commenced recovery of these deferred transition costs in accordance with the 2003 Act.
- (ii) An amount to represent the cost of funds used during construction and development has been applied based on the value of construction in progress.
- (iii) The Corporation does not record future income tax assets or liabilities for its business activities to the extent that it is expected that the recovery or realization of these amounts will be included in future distribution rates.

ENERSOURCE HYDRO MISSISSAUGA INC.

Notes to Financial Statements (continued)
(In thousands of dollars)

Year ended December 31, 2006

1. Significant accounting policies (continued):

(iv) The Corporation has deferred certain pre-market opening cost of power variances and post-market opening retail settlement variances in accordance with Article 490 of the OEB's Accounting Procedures Handbook.

(v) The Corporation has deferred the recognition of the employer's share of contributions to the Ontario Municipal Employees Retirement System ("OMERS") from January 1, 2004 to April 30, 2006. As of May 1, 2006, the Corporation commenced recovery of the 2004 portion with the remainder expected to be recovered through future distribution rates.

(c) Cash and cash equivalents:

Cash and cash equivalents are defined as cash and bank term deposits or equivalent financial instruments with original maturities upon issue of less than 90 days.

(d) Revenue recognition:

Distribution revenue attributable to the delivery of electricity is based upon OEB-approved distribution tariff rates and is recognized as electricity is delivered to customers, which includes an estimate of unbilled revenue, which represents electricity consumed by customers since the date of each customer's last meter reading. Actual electricity usage could differ from estimates.

Other revenue is recognized as services are rendered or contract milestones are achieved.

(e) Measurement uncertainty:

The preparation of the financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenue and expenses during the year. Accounts receivable are reported based on amounts expected to be recovered less and appropriate allowance for unrecoverable amounts based on prior experience. Unbilled revenue and regulatory assets are reported based on amounts expected to be recovered. Inventories are recorded net of provisions for obsolescence. Amounts recorded for amortization of capital assets are based on estimates of useful life.

ENERSOURCE HYDRO MISSISSAUGA INC.

Notes to Financial Statements (continued)
(In thousands of dollars)

Year ended December 31, 2006

1. Significant accounting policies (continued):

Due to the inherent uncertainty involved in making such estimates, actual results could differ from estimates recorded in preparing these financial statements, including changes as a result of future decisions of the OEB or the Minister of Energy.

(f) Inventory:

Inventory, which consists of parts and supplies acquired for internal construction or consumption, is valued at the lower of cost and replacement cost. Cost is determined on a weighted moving average basis.

(g) Capital assets:

Capital assets are recorded at cost and include contracted services, materials, labour, engineering costs, overheads and an allowance for the cost of funds used during construction when applied. Certain assets may be acquired or constructed with financial assistance in the form of contributions from developers or customers. The OEB requires that such contributions, whether in cash or in-kind, be offset against the related asset cost. Contributions in-kind are valued at their fair market value at the date of their contribution.

When assets are retired or otherwise disposed of, their original cost and accumulated amortization are removed from the accounts and the related gain or loss is included in the operating results for the related fiscal period. The cost and related accumulated amortization of grouped assets, such as transmission and distribution facilities, is removed from the accounts at the end of their estimated service lives.

In the event that facts and circumstances indicate that capital assets may be impaired, an evaluation and recoverability is performed. For purposes of such an evaluation, the estimated future undiscounted cash flows associated with the asset are compared to the carrying amount of the asset to determine if a write-down is required. The impairment loss is measured as the amount by which the carrying amount of the asset exceeds its fair value.

ENERSOURCE HYDRO MISSISSAUGA INC.

Notes to Financial Statements (continued)
(In thousands of dollars)

Year ended December 31, 2006

1. Significant accounting policies (continued):

Amortization of capital asset values is charged to operations on a straight-line basis over their estimated service lives as follows:

	Estimated service life	
	Range	Average
Buildings	25 - 60 years	54
Distribution station equipment	15 - 35 years	29
Transmission and distribution system	25 - 40 years	26
Equipment and furniture	4 - 10 years	8
Computer software	2 years	2

Amortization is recorded at one-half the usual annual rate for assets placed into service in the current fiscal period.

Construction in progress comprises capital assets under construction, assets not yet placed into service and pre-construction activities related to specific projects expected to be constructed.

An allowance for the cost of funds used during the construction period has been applied. The rate applied for the 2005 year and the period from January through April 2006 was 6.9% as allowed by the OEB. Effective May 1, 2006, the prescribed interest rate used during the period equals the Scotia Capital Inc. mid-term all corporate average weighted yield, as published on the Bank of Canada's website, updated quarterly. From May 1, 2006 to June 30, 2006, the rate used was 4.68%. From July 1, 2006 to September 30, 2006, the rate used was 5.05%. From October 1, 2006 to December 31, 2006, the rate used was 4.72%.

(h) Deferred debt issue costs:

Deferred debt issue costs represent the cost of the issuance of the bonds. Amortization is provided on a straight-line basis over the term of the related bonds.

ENERSOURCE HYDRO MISSISSAUGA INC.

Notes to Financial Statements (continued)
(In thousands of dollars)

Year ended December 31, 2006

1. Significant accounting policies (continued):

(i) Consumer deposits:

Customers may be required to post security to obtain electricity or other services. Where the security posted is in the form of cash or cash equivalents, these amounts are recorded in the accounts as cash and cash equivalents held for consumer deposits, which are reported separately from the Corporation's own cash and cash equivalents.

Interest rates paid on customer deposits are based on a variable rate of prime less 2.0%, updated quarterly.

(j) Pension and other post-employment benefits:

The Corporation accounts for its participation in OMERS, a multi-employer public sector pension fund, as a defined contribution plan. The Corporation has obtained approval from the OEB to defer pension expenses incurred from January 1, 2004 to April 30, 2006. Effective May 1, 2006, the Corporation commenced recognition of expenses related to contributions to OMERS.

The Corporation actuarially determines the cost of other employment and post-employment benefits offered to employees using the projected benefit method, prorated on service and based on management's best estimate assumptions. Under this method, the projected post-retirement benefit is deemed to be earned on a pro rata basis over the years of service in the attribution period commencing at date of hire, and ending at the earliest age the employee could retire and qualify for benefits.

(k) Regulatory assets and liabilities:

Regulatory assets primarily represent costs that have been deferred because they are expected to be recovered in rates. Similarly, regulatory liabilities can arise from differences in amounts billed to customers under the regulated pricing mechanism and the corresponding wholesale market cost of power incurred by the utility. The OEB directed the distribution utilities to recover these variance balances as at December 31, 2003 plus accrued interest in the rates over a four-year period beginning April 2004.

ENERSOURCE HYDRO MISSISSAUGA INC.

Notes to Financial Statements (continued)
(In thousands of dollars)

Year ended December 31, 2006

1. Significant accounting policies (continued):

Regulatory balances are comprised principally as follows:

- (i) Transition costs - represent costs related to the transition to a competitive electricity market, mandated by the Electricity Act, 1998. The OEB has established rules in respect of transition costs, to qualify amounts for deferral and amortization against future revenue. The Corporation's transition costs have been reviewed via an oral hearing and recovery has been decided upon by the OEB in its December 9, 2004 decision.
- (ii) Pre-market opening cost of power variances - represents amounts accumulated as a result of the excess of the cost of power purchased by the Corporation over the amount billed for this power prior to the market opening. The OEB directed utilities to accumulate such variances in the period leading up to market opening.
- (iii) Post-market opening retail settlement variances - are variances that have occurred since May 1, 2002 when the competitive electricity market was declared open and that have accumulated pursuant to direction from the OEB. Specifically, these amounts include variances between the amounts charged by the Independent Electricity System Operator ("IESO") for the operation of the markets and grid, as well as various wholesale market settlement charges and transmission charges as compared to the amount billed to consumers based on the OEB-approved rates.
- (iv) All revenue and associated costs for the smart meter program have been deferred as directed by the OEB in its April 12, 2006 rate decision.

In November 2003, the Province of Ontario introduced the 2003 Act, which implemented a new electricity pricing regime believed to better reflect the true cost of electricity.

ENERSOURCE HYDRO MISSISSAUGA INC.

Notes to Financial Statements (continued)
(In thousands of dollars)

Year ended December 31, 2006

1. Significant accounting policies (continued):

The 2003 Act, which received Royal Assent in December 2003, removed the \$0.043/kWh electricity price freeze established under the Electricity Pricing, Conservation and Supply Act, 2002 and gives the OEB the power to establish the electricity commodity price for low volume consumers and designated consumers who do not choose an electricity retailer. On April 1, 2004, the government implemented an interim pricing plan under which the first 750 kWh consumed in any month by low volume and designated consumers was priced at \$0.047/kWh and consumption above that level for these consumers was priced at a higher rate of \$0.055/kWh. On April 1, 2005, electricity prices increased from \$0.047/kWh to \$0.050/kWh for the first 750 kWh consumed in a month, and from \$0.055/kWh to \$0.058/kWh for consumption in excess of that amount. In the event that these interim prices exceeded the costs paid by the Ontario Electricity Financial Corporation ("OEFC"), the 2003 Act included a provision permitting the making of regulations requiring distributors, retailers or the IESO to credit consumers for the difference. Under the 2003 Act, regulations may also be made to compensate distributors, retailers and the IESO for making any such payments.

In November 2003, the Province of Ontario announced its intention to allow electricity distributors to recover deferred transition costs and energy variances over a four-year period commencing April 1, 2004. In January 2004, in compliance with regulatory direction, the Corporation submitted to the OEB an application to recover 25% of the December 31, 2002 balance of these regulatory assets. On December 9, 2004, the OEB awarded the Corporation \$26,700 for the recovery of regulatory balances as at December 31, 2003, plus interest, as determined by a Regulatory Hearing.

On April 1, 2006, the Corporation implemented the final rate increase, as permitted by the OEB, toward achieving a market-based rate of return. The initial twelve months of this incremental revenue will be fully invested in electricity conservation and demand management strategies by September 2007.

On April 12, 2006, the OEB announced further changes to electricity prices for regulated price plan customers to take effect May 1, 2006. Electricity prices increased effective May 1, 2006 from \$0.050/kWh to \$0.058/kWh for the first 600 kWh consumed in a month and from \$0.058/kWh to \$0.067/kWh for consumption in excess of that amount. The price threshold is 600 kWh from the May 1 through October 31 period and 1,000 kWh per month during the November 1 through April 30 period. The threshold for non-residential customers that are eligible for the regulated price plan will remain at 750 kWh per month throughout the year.

ENERSOURCE HYDRO MISSISSAUGA INC.

Notes to Financial Statements (continued)
(In thousands of dollars)

Year ended December 31, 2006

1. Significant accounting policies (continued):

On October 11, 2006, the OEB announced further changes to electricity prices for regulated price plan customers to take effect November 1, 2006. Electricity prices decreased effective November 1, 2006 from \$0.058/kWh to \$0.055/kWh for the first 1,000 kWh consumed in a month and from \$0.067/kWh to \$0.064/kWh for consumption in excess of that amount. These prices will be adjusted every six months by the OEB as required.

In August 2005, the Corporation submitted a rate application to the OEB for the rate period beginning May 1, 2006 and ending on April 30, 2007. This rate application proposes the full re-basing of the Corporation's electricity distribution rates to more accurately reflect the Corporation's current rate base and cost structure. On April 12, 2006, the OEB released its decision and order regarding the Corporation's rate application. This decision allows for a distribution rate increase of approximately 2.3% on the total bill of an average residential customer using 1,000 kWh per month. The decision also allows for a newly introduced rate increase for smart meters.

On June 12, 2006, the Corporation submitted a review and vary motion to the OEB to revise its approved 2006 tariff of rates and charges. On October 3, 2006, the OEB released its final decision regarding this motion. The decision allows for additional expense recoveries of \$1,152 annually and a \$2,714 adjustment to dispose of the liability balances recorded in the Corporation's retail settlement variance accounts as of December 31, 2004 over a two-year period.

2. Payments in lieu of corporate income taxes:

Under the Electricity Act, 1998, the Corporation is required to make payments in lieu of corporate income taxes ("PILs") to OEFC. These payments are calculated in accordance with the rules for computing income and taxable capital and other relevant amounts contained in the Income Tax Act (Canada) and the Corporations Tax Act (Ontario), as modified by the Electricity Act, 1998, and related regulations.

The Corporation provides for PILs related to its operations using the taxes payable method as directed by the OEB. Under the taxes payable method, no provisions are made for future income taxes as a result of temporary differences between the tax basis of assets and liabilities and their carrying amounts for accounting purposes.

Management believes that when unrecorded future income taxes become payable, or the assets are realized, it is expected that they will be included in rates approved by the OEB and recovered from customers at that time.

ENERSOURCE HYDRO MISSISSAUGA INC.

Notes to Financial Statements (continued)
(In thousands of dollars)

Year ended December 31, 2006

2. Payments in lieu of corporate income taxes (continued):

Based on substantively enacted income tax rates, the potential benefit of unrecorded future income tax assets arising substantially from differences between accounting and tax values for capital assets is \$37,515 (2005 - \$43,923). Future income taxes have not been recorded in the accounts as they are expected to be recovered through future revenue.

3. Capital assets:

			2006	2005
	Cost	Accumulated amortization	Net book value	Net book value
Land	\$ 4,071	\$ -	\$ 4,071	\$ 4,071
Buildings	14,575	4,755	9,820	9,603
Distribution station equipment	78,153	32,018	46,135	44,198
Transmission and distribution system	591,568	274,117	317,451	317,463
Equipment and furniture	25,813	14,019	11,794	10,370
Computer software	2,910	1,200	1,710	1,030
Construction in progress:				
Equipment and furniture	89	-	89	
Electric distribution system	8,341	-	8,341	7,312
Buildings	34	-	34	1
	\$ 725,554	\$ 326,109	\$ 399,445	\$ 394,048

During the year, \$406 (2005 - \$438), representing an allowance for the cost of funds used during construction, was capitalized to construction in progress.

ENERSOURCE HYDRO MISSISSAUGA INC.

Notes to Financial Statements (continued)
(In thousands of dollars)

Year ended December 31, 2006

4. Regulatory assets and liabilities:

Regulatory assets and liabilities can arise as a result of the rate-making process. The following table demonstrates the impact on 2006 earnings, net of PILs, as a result of regulated accounting requirements.

	2006	2005	Estimated remaining settlement period (years)	2006 Impact on earnings net of PILs (a)(i)
Regulatory assets:				
Deferred OMERS employer contributions ((a)(ii))	\$ 1,372	\$ 1,916	1 - 2	\$ (331)
Other regulatory assets ((a)(iii))	1,549	1,436	1 - 2	(702)
Smart meter revenue/expense ((a)(iv))	(268)	—	4	268
	2,653	3,352		(765)
Regulatory assets approved for recovery ((a)(v))	9,526	17,662	2 - 3	3,454
	\$ 12,179	\$ 21,014		\$ 2,689
Regulatory liabilities:				
Retail settlement variances ((a)(vi))	\$ 11,996	\$ 2,276	1	\$ 491
Global adjustment retail settlement variance ((a)(vii))	(6,713)	6,402	1	(174)
	\$ 5,283	\$ 8,678		\$ 317

(a) Explanatory notes:

- (i) The 2006 impact on earnings net of PILs represents the effect on the net income as a result of the treatment under rate regulated accounting.
- (ii) The OEB had approved the deferral of the Corporation's employer portion of pension contributions to OMERS retirement fund. The deferred OMERS employer contributions amount reflects the Corporation's required contributions between January 1, 2004 and April 30, 2006 plus interest charged at an OEB approved rate less amounts recovered through distribution rates since May 1, 2006.

ENERSOURCE HYDRO MISSISSAUGA INC.

Notes to Financial Statements (continued)
(In thousands of dollars)

Year ended December 31, 2006

4. Regulatory assets and liabilities (continued):

- (iii) The OEB requires that the Corporation record and defer the difference between revenue and costs associated with providing retailers with customer settlement services as retail cost variance account deferrals and had approved the deferral of the Corporation's OEB assessed costs between January 1, 2004 and April 30, 2006. These items are included in other regulatory assets.
- (iv) On June 13, 2006, the OEB issued an update to the Accounting Procedure Handbook regarding the accounting treatment for smart meter expenditures. This amount reflects the net amount of revenue and expenses deferred since May 1, 2006.
- (v) On December 9, 2004, the OEB approved the recovery of the Corporation's regulatory assets as at December 31, 2003. On October 3, 2006, the OEB approved the disposition of the Corporation's retail settlement variance accounts as of December 31, 2004. This amount reflects the total approved regulatory assets for recovery plus interest charged at an OEB approved rate less amounts recovered through distribution rates since April 1, 2004.
- (vi) The OEB requires the Corporation to record and defer the difference between energy charged to its customers and the actual cost of power incurred and paid to the IESO and to Hydro One. The retail settlement variance reflects this difference since January 1, 2005 plus interest charged at an OEB approved rate.
- (vii) The Global Adjustment account for the difference between the market prices and rates paid to regulated and contracted generators and which are set by the IESO. This adjustment may be positive or negative. The Global Adjustment retail settlement variance captures the unpaid or recoverable amounts due to or recoverable from the Corporation's customers.

The Corporation has accrued interest on the deferral account balances for the regulatory assets and retail settlement variances, as directed by the OEB. As at December 31, 2006, this net accrued interest amounted to \$413 (2005 - \$1,022).

ENERSOURCE HYDRO MISSISSAUGA INC.

Notes to Financial Statements (continued)
(In thousands of dollars)

Year ended December 31, 2006

4. Regulatory assets and liabilities (continued):

(b) Financial statement effects of rate regulation:

(i) General information regarding rate regulation and its economic effects:

The operations of the Corporation are regulated by the OEB. The OEB exercises statutory authority over matters such as construction, rates and underlying accounting practices, and rate setting issues with the Corporation's customers.

On April 12, 2006, the Corporation's rate application was approved by the OEB for the rate period beginning May 1, 2006 and ending on April 30, 2007. These rates are set by the OEB under a cost service methodology that allows revenue to recover utility operating costs plus a regulated rate of return on the equity financed portion of the Corporation's rate base. The allowed rate of return for this rate period is set by the OEB at 9.0%.

(ii) Regulatory risk and uncertainties affecting recovery or settlement:

The regulatory assets and liabilities recorded in the financial statements are based upon an expectation of the future actions of the OEB. To the extent that the OEB's future actions are different from the Corporation's expectations, the timing and amount of recovery or settlement of amounts recorded on the balance sheets could be significantly different from the timing and amounts that are eventually recovered or settled.

(iii) Financial statement effects:

In order to recognize the economic effects of the actions or expected actions of the regulator, the timing of recognition of certain revenue and expenses in these operations may differ from that otherwise expected under GAAP for non-rate regulated entities.

Regulatory assets represent amounts that are expected to be recovered from customers in future periods through the rate setting process. In the absence of rate regulated accounting, GAAP would not permit deferral of regulatory assets and, therefore, the earnings impact would be recorded in the period of recovery. Long-term regulatory assets are recorded in other assets in the balance sheets.

ENERSOURCE HYDRO MISSISSAUGA INC.

Notes to Financial Statements (continued)
(In thousands of dollars)

Year ended December 31, 2006

4. Regulatory assets and liabilities (continued):

Regulatory liabilities represent amounts that are expected to be refunded to customers as a result of the rate-setting process. The GAAP treatment of regulatory liabilities and the resulting earnings impact is the same as that under rate regulated accounting because the liabilities represent contractual obligations. Regulatory liabilities are recorded in current liabilities in the balance sheets.

(c) Other items affected by rate regulation:

Future income taxes:

The Corporation recovers tax expense based on the taxes payable method as prescribed by the OEB. As such, the rates approved by the OEB do not include the recovery of future income taxes related to temporary differences. Consequently, the financial statements do not record future income taxes as the future income taxes will be recovered in future rates when they become payable. GAAP requires the recognition of future income tax liabilities and future income tax assets in the absence of rate regulation.

5. Bonds payable:

	2006	2005
6.29% BPC-Enersource Series Bonds, Tranche 1, due May 3, 2011	\$ 290,000	\$ 290,000

Interest expense includes \$18,241 (2005 - \$18,241) in respect of interest on long-term liabilities and amortization of debt issue costs in the amount of \$434 (2005 - \$434).

ENERSOURCE HYDRO MISSISSAUGA INC.

Notes to Financial Statements (continued)
(In thousands of dollars)

Year ended December 31, 2006

6. Capital stock:

(a) Background:

Mississauga City Council approved a by-law, effective January 1, 2000, affecting the transfer of the electricity distribution business formerly conducted by the Mississauga Hydro-Electric Commission to the Corporation. The City received consideration in the form of a note receivable for \$150,000 and common shares in exchange, at the time of the transfer. On December 6, 2001, the City received further consideration in the form of a note receivable for \$119,214 and a dividend of \$20,785 when it exchanged shares issued on January 1, 2000 for shares of Enersource Corporation, the Corporation's parent. The transfers were recorded at net book value.

(b) Capital stock:

	2006	2005
Authorized:		
Unlimited common shares		
Issued:		
40 common shares	\$ 155,629	\$ 155,629

In 2006, the Corporation declared and paid a dividend to its shareholder in the amount of \$8,900 (2005 - \$6,294).

7. Change in non-cash operating working capital:

	2006	2005
Accounts receivable	\$ (8,169)	\$ (5,648)
Unbilled revenue	13,167	(13,291)
Amounts due to/from related parties	(114)	(941)
Inventory	(549)	(764)
Prepaid expenses and deposits	16	(196)
Accounts payable and accrued liabilities	(36,949)	42,096
Payments in lieu of corporate income taxes payable	(2,465)	5,238
Advance payments	1,218	(994)
Regulatory liabilities	(3,395)	497
	\$ (37,240)	\$ 25,997

ENERSOURCE HYDRO MISSISSAUGA INC.

Notes to Financial Statements (continued)
(In thousands of dollars)

Year ended December 31, 2006

8. Employee retirement and post-retirement benefits:

(a) Pensions:

During fiscal 2006, employer contributions were \$1,585 (2005 - \$1,335). With the OEB's approval, the Corporation has deferred \$331 of its 2006 pension expense for recovery in future rates (2005 - \$1,042).

(b) Other retirement and post-retirement benefits:

The Corporation presently offers two separate retirement and post-retirement benefit plans. The total employee retirement and post-retirement benefits liability for the two plans as at December 31, 2006 was \$2,583. The amounts presented are based upon an actuarial valuation performed as of December 31, 2006 on March 2, 2007. The next valuation is expected to be performed for the year ending December 31, 2009.

(c) Retirement and post-retirement life benefits:

(i) Accrued benefit obligation:

	2006	2005
Accrued benefit obligation, beginning of year	\$ 2,140	\$ 2,049
Service cost	81	32
Interest cost	122	133
Benefits paid	(70)	(74)
Unrecognized actuarial loss	138	—
Accrued benefit obligation, end of year	\$ 2,411	\$ 2,140

(ii) Reconciliation of accrued benefit obligation to balance sheet liability:

	2006	2005
Accrued benefit obligation, end of year	\$ 2,411	\$ 2,140
Unrecognized actuarial loss	(138)	—
Post-employment benefits liability	\$ 2,273	\$ 2,140

ENERSOURCE HYDRO MISSISSAUGA INC.

Notes to Financial Statements (continued)
(In thousands of dollars)

Year ended December 31, 2006

8. Employee retirement and post-retirement benefits (continued):

(iii) Significant assumptions:

	2006	2005
Discount rate	5.25%	6.50%
Rate of compensation increase	2.50%	3.00%

The principal funding obligation of the plan is to fund life insurance benefits based on employment date and years of service. A limited group of former employees who elected to retire under a special early retirement incentive plan is entitled to continuation of health and dental premiums at their own expense, until age 65. Accordingly, based on the current participation profile, changes in health and dental care costs will not significantly impact the estimates of the plan obligations. Net actuarial gains or losses over 10% of the accrued benefit obligation are amortized into expense on a straight-line basis over the expected average remaining service lifetime. The total post-retirement benefits liability at December 31, 2006 is \$2,273 (2005 - \$2,140). There are no transition obligations to be amortized from past services.

A 1% increase (decrease) in the interest assumption would decrease (increase) the post-retirement benefit obligation and the service cost by approximately 14% to 16%.

The Corporation's net life insurance benefit expense is as follows:

	2006	2005
Current service cost	\$ 81	\$ 32
Interest cost	122	133
	\$ 203	\$ 165

ENERSOURCE HYDRO MISSISSAUGA INC.

Notes to Financial Statements (continued)
(In thousands of dollars)

Year ended December 31, 2006

8. Employee retirement and post-retirement benefits (continued):

(d) Retirement and post-retirement health and dental benefits:

(i) Accrued benefit obligation:

	2006	2005
Change in benefit obligations:		
Accrued benefit obligation, beginning of year	\$ —	\$ —
Service cost	112	—
Amortization of transition obligation	135	—
Interest cost	63	—
Benefits paid	—	—
Transition obligation	1,081	—
Actuarial losses	143	—
Accrued benefit obligation, end of year	\$ 1,534	\$ —

(ii) Reconciliation of accrued benefit obligation to balance sheet liability:

	2006	2005
Accrued benefit obligation, end of year	\$ 1,534	\$ —
Unrecognized transition obligation	(1,081)	—
Unrecognized actuarial loss	(143)	—
Post-employment benefits liability	\$ 310	\$ —

(iii) Significant assumptions:

	2006	2005
Discount rate	5.25%	—
Expected return on plan assets	5.25%	—
Health care cost increases	15.00%	—
Dental cost increases	5.00%	—

ENERSOURCE HYDRO MISSISSAUGA INC.

Notes to Financial Statements (continued)
(In thousands of dollars)

Year ended December 31, 2006

8. Employee retirement and post-retirement benefits (continued):

The Corporation's net health and dental benefit expense is as follows:

	2006	2005
Amortization of transition obligation	\$ 135	\$ —
Current service cost	112	—
Interest cost	63	—
	<u>\$ 310</u>	<u>\$ —</u>

The principal funding obligation of the plan is to fund health and dental benefits to those employees who retire on or after age 55 with at least 10 years of service with a specified cost sharing formula for participation from the time of early retirement to age 65. Net actuarial gains or losses over 10% of the accrued benefit obligation are amortized into expenses on a straight-line basis over the expected average remaining service lifetime. The total post-employment benefit liability at December 31, 2006 is \$383 (2005 - nil). The unrecognized transition obligation will be amortized over the expected average remaining service lifetime.

For December 31, 2006, health care costs were assumed to increase by 15%, then grading down to 4% per annum after 10 years. Dental costs were assumed to increase by 5% in 2006, then grading down to 3% per annum after 10 years.

A 1% increase (decrease) in the interest assumption would decrease (increase) the expected post-retirement benefit obligation, the interest cost and the service cost by approximately 10%.

9. Contingencies:

(a) Insurance claims:

The Corporation is a member of the Municipal Electric Association Reciprocal Insurance Exchange ("MEARIE"). A reciprocal insurance exchange may be defined as a group of persons formed for the purpose of exchanging reciprocal contracts of indemnity or inter-insurance with each other. MEARIE is licensed to provide general liability insurance to its members.

Insurance premiums charged to each member consist of a levy per thousand dollars of service revenue subject to a credit or surcharge based on each member's claims experience. Current coverage is provided to a level of \$30,000 per incident.

ENERSOURCE HYDRO MISSISSAUGA INC.

Notes to Financial Statements (continued)
(In thousands of dollars)

Year ended December 31, 2006

9. Contingencies (continued):

The Corporation has been jointly named as a defendant in several actions. No provision has been made for these potential liabilities as the Corporation expects that these claims are adequately covered by its insurance.

(b) Other claims:

A class action claiming \$500,000 in restitutionary payments plus interest was served on Toronto Hydro on November 18, 1998. The action was initiated against the former Toronto Hydro-Electric Commission as the representative of the Defendant Class, consisting of all municipal electric utilities in Ontario, which have charged late payment charges on overdue utility bills at any time after April 1, 1981.

The claim is that late payment penalties result in the municipal electric utilities receiving interest at effective rates in excess of 60% per year, which is illegal under Section 347(1)(b) of the Criminal Code.

The Electricity Distributors Association is undertaking the defence of this class action. At this time, it is not possible to quantify the effect, if any, on the financial statements of the Corporation. It is the Corporation's position that any late payment charges that are required to be repaid to customers as a result of this class action would be included in a rate adjustment application to the OEB for full recovery.

On April 22, 2004, the Supreme Court of Canada released its decision in a case commenced against Enbridge Gas Distribution ("EGD") with respect to late payment penalties. At the end of 2006, a mediation process resulted in the settlement of the damages payable by EGD. After the release by the Supreme Court of Canada of its 2004 decision in the EGD case, the plaintiffs in the electric utilities late payment class action indicated their intention to proceed with their litigation. To date, no formal steps have been taken to move the action forward. Any implications of the EGD decision in the Toronto Hydro class action cannot be determined at this time.

(c) Environmental matters:

As part of the Corporation's risk mitigation strategy, an environmental assessment is underway. At this time, it is not possible to determine the final outcome of this assessment.

ENERSOURCE HYDRO MISSISSAUGA INC.

Notes to Financial Statements (continued)
(In thousands of dollars)

Year ended December 31, 2006

10. Commitments:

(a) Guarantees:

Purchasers of electricity in Ontario, through the IESO, are required to provide security to mitigate the risk of their default on their expected activity in the market. The IESO could draw on these guarantees if the Corporation failed to make payment required by a default notice issued by the IESO. The Corporation has provided the IESO with a letter of credit in the amount of \$16,618 (2005 - \$16,618).

(b) Lease commitments:

The Corporation leases equipment under operating lease agreements. The minimum lease payments due in 2007 under these agreements is \$2.

11. Financial instruments:

The carrying values of cash and cash equivalents, accounts receivable, cash and cash equivalents held for consumer deposits, accounts payable and accrued liabilities, advance payments and amounts due to and from related parties approximate fair values because of the short maturity of these financial instruments.

The bonds payable, having a carrying value of \$290,000 (2005 - \$290,000), have a fair value of \$310,854 (2005 - \$316,329) based on year-end quoted market prices.

Financial assets held by the Corporation expose it to credit risk. As at December 31, 2006 and 2005, there were no significant concentrations of credit risk with respect to any class of financial assets. The Corporation earns its revenue from a broad base of customers located principally in Mississauga. No single customer would account for revenue or an accounts receivable balance in excess of 10% of the respective reported balances.

ENERSOURCE HYDRO MISSISSAUGA INC.

Notes to Financial Statements (continued)
(In thousands of dollars)

Year ended December 31, 2006

12. Related party transactions:

The Corporation provides electricity and services to the principal shareholder of its parent company, the City. Electricity is billed to the City at the price and terms established between the City and its electricity retailer. Other construction services are provided at cost. A summary of amounts charged by the Corporation to the City is as follows:

	2006	2005
Electrical energy	\$ 6,751	\$ 7,572
Streetlighting energy	3,371	4,013

The Corporation charged the City \$479 for other construction services in 2006 (2005 - \$439).

The Corporation charged BPC Energy Corporation ("BPC") \$7 (2005 - nil) for an access agreement and nil (2005 - \$159) for consulting services in 2006. These transactions were recorded at the exchange amount being the amount agreed to by the parties. At December 31, 2006, accounts receivable included \$1 (2005 - \$24) due from BPC.

During 2006, the Corporation was charged \$7,620 (2005 - \$6,367) by Enerpower, a company under common ownership, for construction of distribution infrastructure.

At December 31, 2006, accounts payable and accrued liabilities include \$57 (2005 - \$96) due to the City and accounts receivable includes \$1,885 (2005 - \$1,855) due from the City.

Amounts due from related party include \$1,352 (2005 - \$53) from a company under common control.

Amounts due to related parties include \$1,427 (2005 - \$355) to a company under common control and \$945 (2005 - \$832) to the parent company.

13. Energy purchases:

As a participant in the competitive electricity market, all electricity purchases for standard supply customers are subject to pricing determined by the IESO, a provincial government body.

Included in accounts payable and accrued liabilities as at December 31, 2006 is \$49,974 (2005 - \$64,832) owed in respect of electricity purchases through the IESO.

ENERSOURCE HYDRO MISSISSAUGA INC.

Notes to Financial Statements (continued)
(In thousands of dollars)

Year ended December 31, 2006

14. Comparative figures:

Certain comparative figures have been reclassified to conform with the financial statement presentation adopted in the current year.

T2 CORPORATION INCOME TAX RETURN

200

This form serves as a federal, provincial, and territorial corporation income tax return, unless the corporation is located in Quebec, Ontario, or Alberta. If the corporation is located in one of these provinces, you have to file a separate provincial corporation return.

Parts, sections, subsections, and paragraphs mentioned on this return refer to the *Income Tax Act*. This return may contain changes that had not yet become law at the time of printing. For more information on how to complete the return, see the *T2 Corporation - Income Tax Guide* (T4012).

Send one completed copy of this return, including schedules and the *General Index of Financial Information* (GIFI), to your tax services office or tax centre. You have to file the return within six months after the end of the corporation's tax year. For more information on when and how to file T2 returns, refer to the Guide under the heading "Before you start."

055 Do not use this area

Identification

Business Number (BN) 001 88267 0920 RC0001

Corporation's name

002 Enersource Hydro Mississauga Inc.

Has the corporation changed its name since the last time you filed your T2 return? 003 1 Yes ☐ 2 No ☒If Yes, do you have a copy of the articles of amendment? (Do Not Submit) 004 1 Yes ☐ 2 No ☐

Address of head office

Has this address changed since the last time you filed your T2 return? 010 1 Yes ☐ 2 No ☒
(If Yes, complete lines 011 to 018)

011 3240 Mavis Road

012 City Province, territory, or state
015 Mississauga 016 ON017 Country (other than Canada) 018 Postal code/Zip code
018 L5C 3K1

Mailing address (if different from head office address)

Has this address changed since the last time you filed your T2 return? 020 1 Yes ☐ 2 No ☒
(If Yes, complete lines 021 to 028)

021 c/o

022 City Province, territory, or state
025 Mississauga 026 ON027 Country (other than Canada) 028 Postal code/Zip code
028 L5C 3K1

Location of books and records

Has the location of books and records changed since the last time you filed your T2 return? 030 1 Yes ☐ 2 No ☒
(If Yes, complete lines 031 to 038)

031 3240 Mavis Road

032 City Province, territory, or state
035 Mississauga 036 ON037 Country (other than Canada) 038 Postal code/Zip code
038 L5C 3K1

040 Type of corporation at the end of the tax year

- 1 ☒ Canadian-controlled private corporation (CCPC) 4 ☐ Corporation controlled by a public corporation
2 ☐ Other private corporation 5 ☐ Other corporation (specify, below)
3 ☐ Public corporation

If the type of corporation changed during the tax year, provide the effective date of the change 043

YYYY MM DD

To which tax year does this return apply?

Tax year start Tax year-end
060 2006-01-01 061 2006-12-31
YYYY MM DD YYYY MM DDHas there been an acquisition of control to which subsection 249(4) applies since the previous tax year? 063 1 Yes ☐ 2 No ☒If Yes, provide the date control was acquired 065
YYYY MM DDIs the corporation a professional corporation that is a member of a partnership? 067 1 Yes ☐ 2 No ☒

Is this the first year of filing after:

Incorporation? 070 1 Yes ☐ 2 No ☒
Amalgamation? 071 1 Yes ☐ 2 No ☒

If Yes, complete lines 030 to 038 and attach Schedule 24.

Has there been a wind-up of a subsidiary under section 88 during the current tax year? 072 1 Yes ☐ 2 No ☒

If Yes, complete and attach Schedule 24.

Is this the final tax year before amalgamation? 076 1 Yes ☐ 2 No ☒Is this the final return up to dissolution? 078 1 Yes ☐ 2 No ☒

Is the corporation a resident of Canada?

080 1 Yes ☒ 2 No ☐ If No, give the country of residence on line 081 and complete and attach Schedule 97.

081

Is the non-resident corporation claiming an exemption under an income tax treaty? 082 1 Yes ☐ 2 No ☒
If Yes, complete and attach Schedule 91.

If the corporation is exempt from tax under section 149, tick one of the following boxes:

- 085 1 ☐ Exempt under paragraph 149(1)(e) or (l)
2 ☐ Exempt under paragraph 149(1)(j)
3 ☐ Exempt under paragraph 149(1)(t)
4 ☐ Exempt under other paragraphs of section 149

Do not use this area

091 092 093 094 095 096
100

Attachments**Financial statement information:** Use GIFI schedules 100, 125, and 141.**Schedules – Answer the following questions. For each Yes response, attach to the T2 return the schedule that applies.**

	Yes	Schedule
Is the corporation related to any other corporations?	☒	9
Is the corporation an associated Canadian-controlled private corporation?	☒	23
Is the corporation an associated Canadian-controlled private corporation that is claiming the expenditure limit?	☐	49
Does the corporation have any non-resident shareholders?	☐	19
Has the corporation had any transactions, including section 85 transfers, with its shareholders, officers, or employees, other than transactions in the ordinary course of business? Exclude non-arm's length transactions with non-residents	☐	11
If you answered Yes to the above question, and the transaction was between corporations not dealing at arm's length, were all or substantially all of the assets of the transferor disposed of to the transferee?	☐	44
Has the corporation paid any royalties, management fees, or other similar payments to residents of Canada?	☐	14
Is the corporation claiming a deduction for payments to a type of employee benefit plan?	☐	15
Is the corporation claiming a loss or deduction from a tax shelter acquired after August 31, 1989?	☐	T5004
Is the corporation a member of a partnership for which a partnership identification number has been assigned?	☐	T5013
Did the corporation, a foreign affiliate controlled by the corporation, or any other corporation or trust that did not deal at arm's length with the corporation have a beneficial interest in a non-resident discretionary trust?	☐	22
Did the corporation have any foreign affiliates during the year?	☐	25
Has the corporation made any payments to non-residents of Canada under subsections 202(1) and/or 105(1) of the federal <i>Income Tax Regulations</i> ?	☐	29
Has the corporation had any non-arm's length transactions with a non-resident?	☐	T106
For private corporations: Does the corporation have any shareholders who own 10% or more of the corporation's common and/or preferred shares?	☒	50
Has the corporation made payments to, or received amounts from, a retirement compensation plan arrangement during the year?	☐	
Is the net income/loss shown on the financial statements different from the net income/loss for income tax purposes?	☒	1
Has the corporation made any charitable donations; gifts to Canada, a province, or a territory; or gifts of cultural or ecological property?	☐	2
Has the corporation received any dividends or paid any taxable dividends for purposes of the dividend refund?	☒	3
Is the corporation claiming any type of losses?	☐	4
Is the corporation claiming a provincial or territorial tax credit or does it have a permanent establishment in more than one jurisdiction?	☐	5
Has the corporation realized any capital gains or incurred any capital losses during the tax year?	☐	6
i) Is the corporation claiming the small business deduction and reporting income from: a) property (other than dividends deductible on line 320 of the T2 return), b) a partnership, c) a foreign business, or d) a personal services business; or ii) is the corporation claiming the refundable portion of Part I tax?	☐	7
Does the corporation have any property that is eligible for capital cost allowance?	☒	8
Does the corporation have any property that is eligible capital property?	☒	10
Does the corporation have any resource-related deductions?	☐	12
Is the corporation claiming reserves of any kind?	☐	13
Is the corporation claiming a patronage dividend deduction?	☐	16
Is the corporation a credit union claiming a deduction for allocations in proportion to borrowing or an additional deduction?	☐	17
Is the corporation an investment corporation or a mutual fund corporation?	☐	18
Was the corporation carrying on business in Canada as a non-resident corporation?	☐	20
Is the corporation claiming any federal or provincial foreign tax credits, or any federal or provincial logging tax credits?	☐	21
Is the corporation a non-resident-owned investment corporation claiming an allowable refund?	☐	26*
Does the corporation have any Canadian manufacturing and processing profits?	☐	27
Is the corporation claiming an investment tax credit?	☒	31
Is the corporation claiming any scientific research and experimental development (SR&ED) expenditures?	☐	T661
Is the total taxable capital employed in Canada of the corporation and its related corporations over \$10,000,000?	☒	33/34/35
Is the corporation a member of a related group with one or more members subject to gross Part I.3 tax?	☒	36
Is the corporation claiming a surtax credit?	☐	37
Is the corporation subject to gross Part VI tax on capital of financial institutions?	☐	38
Is the corporation claiming a Part I tax credit?	☐	42
Is the corporation subject to Part IV.1 tax on dividends received on taxable preferred shares or Part VI.1 tax on dividends paid?	☐	43
Is the corporation agreeing to a transfer of the liability for Part VI.1 tax?	☐	45
Is the corporation subject to Part II - Tobacco Manufacturers' surtax?	☐	46
For financial institutions: Is the corporation a member of a related group of financial institutions with one or more members subject to gross Part VI tax?	☐	39
Is the corporation claiming a Canadian film or video production tax credit refund?	☐	T1131
Is the corporation claiming a film or video production services tax credit refund?	☐	T1177
Is the corporation subject to Part XIII.1 tax?	☐	92 *

* We do not print this schedule.

Attachments – continued from page 2

	Yes	Schedule
Did the corporation have any foreign affiliates that are not controlled foreign affiliates?	256 ☐	T1134-A
Did the corporation have any controlled foreign affiliates?	258 ☐	T1134-B
Did the corporation own specified foreign property in the year with a cost amount over \$100,000?	259 ☐	T1135
Did the corporation transfer or loan property to a non-resident trust?	260 ☐	T1141
Did the corporation receive a distribution from or was it indebted to a non-resident trust in the year?	261 ☐	T1142
Has the corporation entered into an agreement to allocate assistance for SR&ED carried out in Canada?	262 ☐	T1145
Has the corporation entered into an agreement to transfer qualified expenditures incurred in respect of SR&ED contracts?	263 ☐	T1146
Has the corporation entered into an agreement with other associated corporations for salary or wages of specified employees for SR&ED?	264 ☐	T1174

Additional information

Is the corporation inactive?	280 1 Yes ☐ 2 No ☒						
Has the major business activity changed since the last return was filed? (enter Yes for first-time filers)	281 1 Yes ☐ 2 No ☒						
What is the corporation's major business activity? (Only complete if Yes was entered at line 281.)	282 _____						
If the major business activity involves the resale of goods, show whether it is wholesale or retail	283 1 Wholesale ☐ 2 Retail ☐						
Specify the principal product(s) mined, manufactured, sold, constructed, or services provided, giving the approximate percentage of the total revenue that each product or service represents.	<table border="0"><tr><td>284 Power distribution</td><td>285 100.000 %</td></tr><tr><td>286 _____</td><td>287 _____ %</td></tr><tr><td>288 _____</td><td>289 _____ %</td></tr></table>	284 Power distribution	285 100.000 %	286 _____	287 _____ %	288 _____	289 _____ %
284 Power distribution	285 100.000 %						
286 _____	287 _____ %						
288 _____	289 _____ %						
Did the corporation immigrate to Canada during the tax year?	291 1 Yes ☐ 2 No ☒						
Did the corporation emigrate from Canada during the tax year?	292 1 Yes ☐ 2 No ☒						

Taxable income

Net income or (loss) for income tax purposes from Schedule 1, financial statements, or GIFL	300 28,493,430 A
Deduct:	
Charitable donations from Schedule 2	311 _____
Gifts to Canada, a province, or a territory from Schedule 2	312 _____
Cultural gifts from Schedule 2	313 _____
Ecological gifts from Schedule 2	314 _____
Taxable dividends deductible under section 112 or 113, or subsection 138(6) from Schedule 3	320 _____
Part VI.1 tax deduction from Schedule 43 *	325 _____
Non-capital losses of preceding tax years from Schedule 4	331 _____
Net capital losses of preceding tax years from Schedule 4	332 _____
Restricted farm losses of preceding tax years from Schedule 4	333 _____
Farm losses of preceding tax years from Schedule 4	334 _____
Limited partnership losses of preceding tax years from Schedule 4	335 _____
Taxable capital gains or taxable dividends allocated from a central credit union	340 _____
Prospector's and grubstaker's shares	350 _____
Subtotal	355 28,493,430 B
Add: Section 110.5 additions or subparagraph 115(1)(a)(vii) additions	360 28,493,430 C
Taxable income (amount C plus amount D)	370 28,493,430 D
Income exempt under paragraph 149(1)(t)	370 _____
Taxable income for a corporation with exempt income under paragraph 149(1)(t) (line 360 minus line 370)	370 28,493,430 Z

* This amount is equal to 3 times the Part VI.1 tax payable at line 724.

Small business deduction

Canadian-controlled private corporations (CCPCs) throughout the tax year

Income from active business carried on in Canada from Schedule 7 **400** 28,493,430 A
Taxable income from line 360, minus 10/3 of the amount on line 632*, minus 3 times the amount on line 636**, and minus any amount that, because of federal law, is exempt from Part I tax **405** 28,493,430 B

Calculation of the business limit:

For all CCPCs, calculate the amount at line 4 below.

250,000 x $\frac{\text{Number of days in the tax year in 2004}}{\text{Number of days in the tax year}}$ = ... 1
300,000 x $\frac{\text{Number of days in the tax year in 2005 and in 2006}}{\text{Number of days in the tax year}}$ = ... 300,000 2
400,000 x $\frac{\text{Number of days in the tax year after 2006}}{\text{Number of days in the tax year}}$ = ... 3
Add amounts at lines 1, 2, and 3 **300,000** 4

Business limit (see notes 1 and 2 below) **410** 300,000 C

- Notes: 1. For CCPCs that are not associated, enter the amount from line 4 on line 410. However, if the corporation's tax year is less than 51 weeks, prorate the amount from line 4 by the number of days in the tax year divided by 365, and enter the result on line 410.
2. For associated CCPCs, use Schedule 23 to calculate the amount to be entered on line 410.

Business limit reduction:

Amount C 300,000 x **415** *** 1,102,500 D = ... 29,400,000 E
11,250

Reduced business limit (amount C minus amount E) (if negative, enter "0") **425** F

Small business deduction

Whichever amount is the least: A, B, C or F G1
Amount G1 x $\frac{\text{Number of days in the tax year before 2008}}{\text{Number of days in the tax year}}$ x 16 % = ... G2
Amount G1 x $\frac{\text{Number of days in the tax year in 2008}}{\text{Number of days in the tax year}}$ x 16.5 % = ... G3
Amount G1 x $\frac{\text{Number of days in the tax year after 2008}}{\text{Number of days in the tax year}}$ x 17 % = ... G4

Small business deduction – total of amounts G2, G3, and G4 (enter amount G on line 9) **430** G

* Calculate the amount of foreign non-business income tax credit deductible on line 632 without reference to the refundable tax on the CCPC's investment income (line 604) and without reference to the corporate tax reductions under section 123.4.

** Calculate the amount of foreign business income tax credit deductible on line 636 without reference to the corporate tax reductions under section 123.4.

*** Large corporations

- If the corporation is not associated with any corporations in both the current and the preceding tax years, the amount to be entered at line 415 is: (Total taxable capital employed in Canada for the prior year minus \$10,000,000) x 0.225%.
- If the corporation is not associated with any corporations in the current tax year, but was associated in the preceding tax year, the amount to be entered at line 415 is: (Total taxable capital employed in Canada for the current year minus \$10,000,000) x 0.225%
- For corporations associated in the current tax year, see Schedule 23 for the special rules that apply.

Resource deduction

Taxable resource income [as defined in subsection 125.11(1)] **435** H
Amount H x $\frac{\text{Number of days in the tax year in 2004}}{\text{Number of days in the tax year}}$ x 2 % = ... I
Amount H x $\frac{\text{Number of days in the tax year in 2005}}{\text{Number of days in the tax year}}$ x 3 % = ... J
Amount H x $\frac{\text{Number of days in the tax year in 2006}}{\text{Number of days in the tax year}}$ x 5 % = ... K
Amount H x $\frac{\text{Number of days in the tax year after 2006}}{\text{Number of days in the tax year}}$ x 7 % = ... L
Resource deduction – total of amounts I, J, K, and L (enter amount M on line 10) **438** M

Taxable income from line 360		_____	M
Amount Z1 from Part 9 of Schedule 27		_____	N
Amount QQ from Part 13 of Schedule 27		_____	O
Taxable resource income from line 435		_____	P
Amount used to calculate the credit union deduction (amount E in Part 3 of Schedule 17)		_____	Q
Total of amounts N, O, P, and Q		_____	R
Amount M minus amount R (if negative, enter "0")		_____	S

General tax reduction (continued)

Amount \$	x	Number of days in the tax year before 2008	365	x	7 %	=	T1
		Number of days in the tax year	365				
Amount \$	x	Number of days in the tax year in 2008		x	7.5 %	=	T2
		Number of days in the tax year	365				
Amount \$	x	Number of days in the tax year in 2009		x	8 %	=	T3
		Number of days in the tax year	365				
Amount \$	x	Number of days in the tax year after 2009		x	9 %	=	T4
		Number of days in the tax year	365				
General tax reduction – total of amounts T1, T2, T3, and T4 (enter amount T on line 639)							T

Refundable portion of Part I tax

Canadian-controlled private corporations throughout the tax year

Aggregate investment income **440** x 26 2 / 3 % = A

Foreign non-business income tax credit from line 632

Deduct:

Foreign investment income **445** x 9 1 / 3 % =
(amount L from Part 2 of Schedule 7) (if negative, enter "0") B

Amount A minus amount B (if negative, enter "0") C

Taxable income from line 360 28,493,430

Deduct:

Amount on line 400, 405, 410, or 425, whichever is the least

Foreign non-business
income tax credit

from line 632 x 25 / 9 =

Foreign business

income tax credit

from line 636 x 3 =

28,493,430

x 26 2 / 3 % = 7,598,248 D

Part I tax payable minus investment tax credit refund (line 700 minus line 780)

6,298,180

Deduct: Corporate surtax from line 600

319,126

Net amount 5,979,054 E

Refundable portion of Part I tax – Amount C, D, or E, whichever is the least

450

F

Refundable dividend tax on hand

Refundable dividend tax on hand at the end of the preceding tax year

460

Deduct: Dividend refund for the previous tax year

465

Add the total of:

Refundable portion of Part I tax from line 450 above

Total Part IV tax payable from line 360 of Schedule 3

Net refundable dividend tax on hand transferred from a predecessor corporation on
amalgamation, or from a wound-up subsidiary corporation

480

H

Refundable dividend tax on hand at the end of the tax year – Amount G plus amount H

485

Dividend refund

Private and subject corporations at the time taxable dividends were paid in the tax year

Taxable dividends paid in the tax year from line 460 of Schedule 3 8,900,000 x 1 / 3 2,966,667 I

Refundable dividend tax on hand at the end of the tax year from line 485 above J

Dividend refund – Amount I or J, whichever is less (enter this amount on line 784)

Part I tax

Base amount of Part I tax – 38.00 % of taxable income (line 360 or amount Z, whichever applies)	550	10,827,503	A
Corporate surtax calculation			
Base amount from line A above		10,827,503	1
Deduct:			
10 % of taxable income (line 360 or amount Z, whichever applies)		2,849,343	2
Investment corporation deduction from line 620 below			3
Federal logging tax credit from line 640 below			4
Federal qualifying environmental trust tax credit from line 648 below			5
For a mutual fund corporation or an investment corporation throughout the tax year, enter amount a, b, or c below on line 6, whichever is the least:			
28.00 % of taxable income from line 360	a		
28.00 % of taxed capital gains	b		
Part I tax otherwise payable (line A plus lines C and D minus line F)	c		6
Total of lines 2 to 6		2,849,343	7
Net amount (line 1 minus line 7)		7,978,160	8
Corporate surtax			
line 8	7,978,160 x 4 % x	Number of days in the tax year before 2008 365 =	600 319,126 B
		Number of days in the tax year 365	
Recapture of investment tax credit from line OO in Part 17 of Schedule 31		602	C
Calculation for the refundable tax on the Canadian-controlled private corporation's (CCPC) investment income (if it was a CCPC throughout the tax year)			
Aggregate investment income from line 440			i
Taxable income from line 360		28,493,430	
Deduct:			
Amount on line 400, 405, 410, or 425, whichever is the least			
Net amount		28,493,430	ii
Refundable tax on CCPC's investment income – 6 2 / 3 % of whichever is less: amount i or ii		604	D
		Subtotal (add lines A, B, C, and D)	11,146,629 E
Deduct:			
Small business deduction from line 430			9
Federal tax abatement	608	2,849,343	
Manufacturing and processing profits deduction from amount BB or amount RR of Schedule 27	616		
Investment corporation deduction (taxed capital gains 624)	620		
Additional deduction – credit unions from Schedule 17	628		
Federal foreign non-business income tax credit from Schedule 21	632		
Federal foreign business income tax credit from Schedule 21	636		
Accelerated tax reduction from amount N	637		
Resource deduction from line 438			10
General tax reduction for CCPCs from amount J	638	1,994,540	
General tax reduction from amount T	639		
Federal logging tax credit from Schedule 21	640		
Federal political contribution tax credit	644		
Federal political contributions 646			
Federal qualifying environmental trust tax credit	648		
Investment tax credit from Schedule 31	652	4,566	
		Subtotal	4,848,449 F
Part I tax payable – Line E minus line F (enter amount G on line 700)			6,298,180 G

Summary of tax and credits

Federal tax

Part I tax payable	700	6,298,180
Part I.3 tax payable from Schedule 33, 34, or 35	704	
Part II surtax payable from Schedule 46	708	
Part IV tax payable from Schedule 3	712	
Part IV.1 tax payable from Schedule 43	716	
Part VI tax payable from Schedule 38	720	
Part VI.1 tax payable from Schedule 43	724	
Part XIII.1 tax payable from Schedule 92	727	
Part XIV tax payable from Schedule 20	728	

Add provincial or territorial tax:

Total federal tax 6,298,180

Provincial or territorial jurisdiction 750 Ontario

(If more than one jurisdiction, enter "multiple" and complete Schedule 5)

Net provincial or territorial tax payable (except Québec, Ontario, and Alberta) 760

Provincial tax on large corporations (New Brunswick and Nova Scotia) 765

Deduct other credits:

Investment tax credit refund from Schedule 31	780	
Dividend refund	784	
Federal capital gains refund from Schedule 18	788	
Federal qualifying environmental trust tax credit refund	792	
Canadian film or video production tax credit refund (Form T1131)	796	
Film or video production services tax credit refund (Form T1177)	797	
Tax withheld at source	800	
Total payments on which tax has been withheld	801	
Allowable refund for non-resident-owned investment corporations from Schedule 26	804	
Provincial and territorial capital gains refund from Schedule 18	808	
Provincial and territorial refundable tax credits from Schedule 5	812	
Tax instalments paid	840	6,298,180
Total credits	890	6,298,180

Total tax payable 770 6,298,180 A

6,298,180 B

Refund code 894 Overpayment

Balance (line A minus line B)

Direct deposit request

To have the corporation's refund deposited directly into the corporation's bank account at a financial institution in Canada, or to change banking information you already gave us, complete the information below:

☐ Start ☐ Change information 910
914 Institution number 918 Branch number
Account number

If the result is negative, you have an overpayment.
If the result is positive, you have a balance unpaid.
Enter the amount on whichever line applies.
Generally, we do not charge or refund a difference of \$2 or less.

Balance unpaid
Enclosed payment 898

If the corporation is a Canadian-controlled private corporation throughout the tax year, does it qualify for the one-month extension of the date the balance of tax is due?

896 1 Yes ☐ 2 No ☒

Certification

I, 950 Last name 951 First name 954 Position, office, or rank
am an authorized signing officer of the corporation. I certify that I have examined this return, including accompanying schedules and statements, and that the information given on this return is, to the best of my knowledge, correct and complete. I further certify that the method of calculating income for this tax year is consistent with that of the previous year except as specifically disclosed in a statement attached to this return.

955 Date (yyyy/mm/dd) Signature of the authorized signing officer of the corporation

Is the contact person the same as the authorized signing officer? If No, complete the information below

958 Name 957 1 Yes ☒ 2 No ☐
959 Telephone number

Language of correspondence – Langue de correspondance

990 Indicate your language of correspondence by entering 1 for English or 2 for French.
Indiquez votre langue de correspondance en inscrivant 1 pour anglais ou 2 pour français.

1 English / Anglais ☒ 2 Français / French ☐

Name of corporation contact: Barry Lewis
Telephone number: (905) 566-2727

- TransferCORPORATE TAXPREP / TAXPREP DES SOCIÉTÉS - EP07

GENERAL INDEX OF FINANCIAL INFORMATION – GIF

Name of corporation	Business Number	Form identifier 100 Tax year end Year Month Day
Enersource Hydro Mississauga Inc.	88267 0920 RC0001	2006-12-31

Balance sheet information

Account	Description	GIFI	Amount	Prior year
Assets				
	Total current assets	1599 +	152,507,000	184,197,000
	Total tangible capital assets	2008 +	725,554,000	700,510,000
	Total accumulated amortization of tangible capital assets	2009 -	326,109,000	306,462,000
	Total intangible capital assets	2178 +		
	Total accumulated amortization of intangible capital assets	2179 -		
	Total long-term assets	2589 +	35,797,000	45,680,000
	* Assets held in trust	2590 +		
	Total assets (mandatory field)	2599 =	<u>587,749,000</u>	<u>623,925,000</u>

Liabilities				
	Total current liabilities	3139 +	90,661,000	131,067,000
	Total long-term liabilities	3450 +	314,323,000	314,494,000
	* Subordinated debt	3460 +		
	* Amounts held in trust	3470 +		
	Total liabilities (mandatory field)	3499 =	<u>404,984,000</u>	<u>445,561,000</u>

Shareholder equity				
	Total shareholder equity (mandatory field)	3620 +	182,765,000	178,364,000
	Total liabilities and shareholder equity	3640 =	<u>587,749,000</u>	<u>623,925,000</u>

Retained earnings				
	Retained earnings/deficit – end (mandatory field)	3849 =	<u>27,136,000</u>	<u>22,735,000</u>

* Generic item

GENERAL INDEX OF FINANCIAL INFORMATION - GIFI

Name of corporation Enersource Hydro Mississauga Inc.	Business Number 88267 0920 RC0001	Form identifier 125 Tax year end Year Month Day 2006-12-31

Income statement information

Description	GIFI	
Operating name	0001	
Description of the operation	0002	
Sequence Number	0003	01

Account	Description	GIFI	Amount	Prior year

Income statement information

Total sales of goods and services	8089 +	671,397,000	782,362,000
Cost of sales	8518 -	557,271,000	672,412,000
Gross profit/loss	8519 =	114,126,000	109,950,000
Cost of sales	8518 +	557,271,000	672,412,000
Total operating expenses	9367 +	93,470,000	90,330,000
Total expenses (mandatory field)	9368 =	650,741,000	762,742,000
Total revenue (mandatory field)	8299 +	674,161,000	784,080,000
Total expenses (mandatory field)	9368 -	650,741,000	762,742,000
Net non-farming income	9369 =	23,420,000	21,338,000

Farming income statement information

Total farm revenue (mandatory field)	9659 +		
Total farm expenses (mandatory field)	9898 -		
Net farm income	9899 =		

Net income/loss before taxes and extraordinary items	9970 =	23,420,000	21,338,000

Extraordinary items and income (linked to Schedule 140)

Extraordinary item(s)	9975 -		
Legal settlements	9976 -		
Unrealized gains/losses	9980 +		
Unusual items	9985 -		
Current income taxes	9990 -	10,119,000	8,559,000
Deferred income tax provision	9995 -		
Net income/loss after taxes and extraordinary items (mandatory field)	9999 =	13,301,000	12,779,000

NOTES CHECKLIST

SCHEDULE 141

Corporation's name Enersource Hydro Mississauga Inc.	Business Number 88267 0920 RC0001	Tax year end Year Month Day 2006-12-31

- This schedule should be completed from the perspective of the person who prepared or reported on the financial statements. This person is referred to as the "accounting practitioner", in this schedule.
- For more information, see RC4088, *Guide to the General Index of Financial Information (GIFI) for Corporations* and T4012, *T2 Corporation – Income Tax Guide*.
- Attach a copy of this schedule, along with any Notes to the financial statements, to the GIFI.

Part 1 – Accounting practitioner information

Does the accounting practitioner have a professional designation? **095** 1 Yes ☒ 2 No ☐

Is the accounting practitioner connected* with the corporation? **097** 1 Yes ☐ 2 No ☒

* A person connected with a corporation can be: (i) a shareholder of the corporation who owns more than 10% of the common shares; (ii) a director, an officer, or an employee of the corporation; or (iii) a person not dealing at arm's length with the corporation.

Note

If the accounting practitioner does not have a professional designation or is connected with the corporation, you do not have to complete Parts 2 and 3 of this schedule. However, you do have to complete Part 4.

Part 2 – Type of involvement

Choose the option that represents the highest level of involvement of the accounting practitioner:

Completed an auditor's report	198 1	☒
Completed a review engagement report	2	☐
Conducted a compilation engagement	3	☐

Part 3 – Reservations

If you selected option "1" or "2" under Type of involvement above, answer the following question:

Has the accounting practitioner expressed a reservation? **099** 1 Yes ☐ 2 No ☒

Part 4 – Other information

Were notes to the financial statements prepared? **101** 1 Yes ☒ 2 No ☐

If Yes, complete lines 102 to 107 below:

Are any values presented at other than cost? **102** 1 Yes ☐ 2 No ☒

Has there been a change in accounting policies since the last return? **103** 1 Yes ☐ 2 No ☒

Are subsequent events mentioned in the notes? **104** 1 Yes ☐ 2 No ☒

Is re-evaluation of asset information mentioned in the notes? **105** 1 Yes ☐ 2 No ☒

Is contingent liability information mentioned in the notes? **106** 1 Yes ☒ 2 No ☐

Is information regarding commitments mentioned in the notes? **107** 1 Yes ☒ 2 No ☐

Does the corporation have investments in joint venture(s) or partnership(s)? **108** 1 Yes ☐ 2 No ☒

If Yes, complete line 109 below:

Are you filing financial statements of the joint venture(s) or partnership(s)? **109** 1 Yes ☐ 2 No ☐

NET INCOME (LOSS) FOR INCOME TAX PURPOSES

SCHEDULE 1

Corporation's name	Business Number	Tax year end
Enersource Hydro Mississauga Inc.	88267 0920 RC0001	Year Month Day 2006-12-31

- The purpose of this schedule is to provide a reconciliation between the corporation's net income (loss) as reported on the financial statements and its net income (loss) for tax purposes. For more information, see the *T2 Corporation Income Tax Guide*.
- Please provide us with the applicable details in the identification area, and complete the applicable lines that contain a numbered black box. You should report amounts in accordance with the Generally Accepted Accounting Principles (GAAP).
- Sections, subsections, and paragraphs referred to on this schedule are from the *Income Tax Act*.

Net income (loss) after taxes and extraordinary items per financial statements 13,301,000 A

Add:

Provision for income taxes – current	101	10,119,000	
Amortization of tangible assets	104	30,275,000	
Loss on disposal of assets	111	2,540	
Non-deductible meals and entertainment expenses	121	33,570	
Reserves from financial statements – balance at the end of the year	126	4,079,952	
Subtotal of additions		44,510,062	44,510,062

Other additions:

Miscellaneous other additions:

600 See attached	290	4,016,722	
601 Capital tax expensed per accounts	291	1,557,076	
602 Smart Meter deferral - Variance Account	292	421,531	
603.2 Ontario Specified Tax Credits			
		35,288	
Total	293	35,288	
Subtotal of other additions	199	6,030,617	6,030,617
Total additions	500	50,540,679	50,540,679

Deduct:

Capital cost allowance from Schedule 8	403	27,877,918	
Cumulative eligible capital deduction from Schedule 10	405	1,568,076	
Reserves from financial statements – balance at the beginning of the year	414	2,140,123	
Subtotal of deductions		31,586,117	31,586,117

Other deductions:

Miscellaneous other deductions:

700 Ontario capital tax per CT-23	390	1,511,809	
701 Debt issue costs - 20(1)(e)	391	652,170	
702 Reserve provision - accrued safety fines 2005	392	100,000	
703 Notional interest income on reg. assets accrued for book	393	412,841	
704.1 See Attached Schedule			
		1,085,312	
Total	394	1,085,312	
Subtotal of other deductions	499	3,762,132	3,762,132
Total deductions	510	35,348,249	35,348,249

Net income (loss) for income tax purposes – enter on line 300 of the T2 return 28,493,430

Attached Schedule with Total

FDONE.Tbwone52

Title Miscellaneous

Description

	Amount
Pension costs paid in year deferred for book	330,735 00
RCVA reserve	128,119 00
OEB fixed costs assessed deferral	214,519 00
AFUDC - interest capitalized for book	405,669 00
Bad debt recovered from previous Oct 2001	6,270 00
Total	1,085,312 00

Capital-gains
Capital-losses

Attached Schedule with Total

Line 290 – Amount for line 600

Title Line 290 -- Amount for line 600

Description	Amount
Recovery of fixed assets in reg assets	2,039,97000
Recovery of notional interest on reg. assets	1,125,73200
Recovery of OEB fixed costs	127,63100
Recovery of pension deferral	289,73400
Recovery of RCVA 134380/134390	7100
Amortization of debt issuance costs	433,58400
Total	4,016,72200

DIVIDENDS RECEIVED, TAXABLE DIVIDENDS PAID, AND
PART IV TAX CALCULATION

SCHEDULE 3

Name of corporation Enersource Hydro Mississauga Inc.	Business Number 88267 0920 RC0001	Tax year end Year Month Day 2006-12-31

- This schedule is for the use of any corporation to report:
 - non-taxable dividends under section 83;
 - deductible dividends under subsection 138(6);
 - taxable dividends deductible from income under section 112, subsection 113(2) and paragraphs 113(1)(a), (b) or (d); or
 - taxable dividends paid for purposes of a dividend refund.
- The calculations in this schedule apply only to private or subject corporations.
- Parts, sections, subsections, and paragraphs referred to on this schedule are from the federal *Income Tax Act*.
- A recipient corporation is connected with a payer corporation at any time in a taxation year, if at that time the recipient corporation:
 - controls the payer corporation, other than because of a right referred to in paragraph 251(5)(b); or
 - owns more than 10% of the issued share capital (with full voting rights), and shares that have a fair market value of more than 10% of the fair market value of all shares of the payer corporation.
- File one completed copy of this schedule with your *T2 Corporation Income Tax Return*.
- For more information, see the sections about Schedule 3 in the *T2 Corporation Income Tax Guide*.
- "X" under column A if dividend received from a foreign source (connected corporation only).
- "X" under column B if the payer corporation is connected.
- "X" under column F1 if the dividends received are eligible to an addition of 45% for the purposes of the dividend tax credit for individuals.
- F2 – Enter the code that applies to the deductible taxable dividend.

Part 1 – Dividends received during the taxation year

Do not include dividends received from foreign non-affiliates.

Name of payer corporation (Use only one line per corporation, abbreviating its name if necessary)	A	B	Complete if payer corporation is connected	
			C Business Number	D Taxation year end of the payer corporation in which the sections 112/113 and subsection 138(6) dividends were paid YYYY/MM/DD
200		205	210	220
1				

Note: If your corporation's taxation year end is different than that of the connected payer corporation, your corporation could have received dividends from more than one taxation year of the payer corporation. If so, use a separate line to provide the information for each taxation year of the payer corporation.

				If payer corporation is not connected, leave these columns blank.			
E Non-taxable dividend under section 83	F Taxable dividends deductible from taxable income under section 112, subsections 113(2) and 138(6), and paragraphs 113(1)(a), (b), or (d)	F1	F2	G Total taxable dividends paid by connected payer corporation	H Dividend refund of the connected payer corporation	I Part IV tax before deductions F x 1 / 3 *	
230	240			250	260	270	
1							
Total (enter amount of column F on line 320 of the T2 return)							

For dividends received from connected corporations: Part IV tax equals: $\frac{\text{Column F} \times \text{Column H}}{\text{Column G}}$

* Life insurers are not subject to Part IV tax on subsection 138(6) dividends.
Public corporations (other than subject corporations) do not need to calculate Part IV tax.

Part 2 – Calculation of Part IV tax payable

Part IV tax before deductions (amount J in Part 1)

Deduct:

Part IV.I tax payable on dividends subject to Part IV tax **320**

Subtotal

Deduct:

Current-year non-capital loss claimed to reduce Part IV tax **330**

Non-capital losses from previous years claimed to reduce Part IV tax **335**

Current-year farm loss claimed to reduce Part IV tax **340**

Farm losses from previous years claimed to reduce Part IV tax **345**

Total losses applied against Part IV tax x 1 / 3 = ...

Part IV tax payable (enter amount on line 712 of the T2 return) **360**

Part 3 – Taxable dividends paid in the taxation year for purposes of a dividend refund

A	B	C	D
Name of connected recipient corporation	Business Number	Taxation year end of connected recipient corporation in which the dividends in column D were received YYYY/MM/DD	Taxable dividends paid to connected corporations
400	410	420	430
1 Enersource Corporation	89858 6417 RC0001	2006-12-31	8,900,000
2			

Note
If your corporation's taxation year end is different than that of the connected recipient corporation, your corporation could have paid dividends in more than one taxation year of the recipient corporation. If so, use a separate line to provide the information for each taxation year of the recipient corporation.

Total **8,900,000**

Total taxable dividends paid in the taxation year to other than connected corporations **450**

Total taxable dividends paid in the taxation year for the purposes of a dividend refund (total of column D above plus line 450) **460** **8,900,000**

Part 4 – Total dividends paid in the taxation year

Complete this part if the total taxable dividends paid in the taxation year for purposes of a dividend refund (line 460 above) is different from the total dividends paid in the taxation year.

Total taxable dividends paid in the taxation year for the purposes of a dividend refund (from above) **460** **8,900,000**

Other dividends paid in the taxation year (total of 510 to 540)

Total dividends paid in the taxation year **500** **8,900,000**

Deduct:

Dividends paid out of capital dividend account **510**

Capital gains dividends **520**

Dividends paid on shares described in subsection 129(1.2) **530**

Taxable dividends paid to a controlling corporation that was bankrupt at any time in the year **540**

Subtotal **8,900,000**

Total taxable dividends paid in the taxation year for purposes of a dividend refund **8,900,000**

CAPITAL COST ALLOWANCE (CCA)

Name of corporation Enersource Hydro Mississauga Inc.		Business Number 88267 0920 RC0001	Tax year end Year Month Day 2006-12-31

For more information, see the section called "Capital Cost Allowance" in the T2 Corporation Income Tax Guide.

Is the corporation electing under regulation 1101(5q)?

101 1 Yes ☐ 2 No ☒

1 Class number	2 Description	3 Undepreciated capital cost at the beginning of the year (undepreciated capital cost at the end of last year)	4 Cost of acquisitions during the year (new property must be available for use)	5 Net adjustments**	6 Proceeds of dispositions during the year (amount not to exceed the capital cost)	7 50% rule (1/2 of the amount, if any, by which the net cost of acquisitions exceeds column 5)**	8 Reduced undepreciated capital cost	9 CCA rate %	10 Recapture of capital cost allowance (line 107 of Schedule 1)	11 Terminal loss (line 404 of Schedule 1)	12 Capital cost allowance (column 7 multiplied by column 8; or a lower amount) (line 403 of Schedule 1)***	13 Undepreciated capital cost at the end of the year (column 6 plus column 7 minus column 11)
200		201	203	205	207	211	212	213	215	217	220	
1		378,561,861	510,144		0	255,072	378,816,933	4	0	0	15,152,677	363,919,328
2		47,841,411			0		47,841,411	6	0	0	2,870,485	44,970,926
8		9,596,179	1,277,051		0	638,526	10,234,704	20	0	0	2,046,941	8,826,289
10		8,770,000	1,523,210		191,232	665,989	9,435,989	30	0	0	2,830,797	7,271,181
98		6,588,925			0		6,588,925	0	0	0		6,588,925
12		472,272	1,965,292		0	982,646	1,454,918	100	0	0	1,454,918	982,646
3		2,774,633			0		2,774,633	5	0	0	138,732	2,635,901
45		863,230	1,519,942		300	759,821	1,623,051	45	0	0	730,373	1,652,499
10.1	GMC ENVOY	20,527			N/A		20,527	30	N/A	N/A	6,158	14,369
10.1	HONDA PILOT	20,527			N/A		20,527	30	N/A	N/A	6,158	14,369
10.1	VOLVO S60	20,527			N/A		20,527	30	N/A	N/A	6,158	14,369
10.1	VOLVO S80	20,527			N/A		20,527	30	N/A	N/A	6,158	14,369
10.1	CHRYSLER PACIFICA	20,527			N/A		20,527	30	N/A	N/A	6,158	14,369
10.1	GMC ENVOY 017-04	20,527			N/A		20,527	30	N/A	N/A	6,158	14,369
10.1	LINCOLN LS	20,527			N/A		20,527	30	N/A	N/A	6,158	14,369
10.1	NISSAN MAXIMA	29,325			N/A		29,325	30	N/A	N/A	8,798	20,527
47		18,061,502	27,896,224		0	13,948,112	32,009,614	8	0	0	2,560,769	43,396,957
10.1	PONTIAC GRAND AM	29,325			N/A		29,325	30	N/A	N/A	8,798	20,527
10.1	DODGE SPRINTER VAN	29,325			N/A		29,325	30	N/A	N/A	8,798	20,527
10.1	Ford Escape Hybrid	29,325			N/A		29,325	30	N/A	N/A	8,798	20,527
10.1	Ford Escape Hybrid	29,325			N/A		29,325	30	N/A	N/A	8,798	20,527
10.1	020-07		34,200		N/A	17,100	17,100	30	N/A	N/A	5,130	29,070
Total		473,820,327	34,726,063		191,532	17,267,266	491,087,592				27,877,918	480,476,940

- Include any property acquired in previous years that has now become available for use. This property would have been previously excluded from column 3. List separately any acquisitions that are not subject to the 50% rule, see Regulation 1100(2) and (2.2).
- Include amounts transferred under section 85, or on amalgamation and winding-up of a subsidiary. See the *T2 Corporation Income Tax Guide* for other examples of adjustments to include in column 4.
- The net cost of acquisitions is the cost of acquisitions (column 3) plus or minus certain adjustments from column 4. For exceptions to the 50% rule, see Interpretation Bulletin IT-285, *Capital Cost Allowance – General Comments*.
- If the tax year is shorter than 365 days, prorate the CCA claim. Some classes of property do not have to be prorated. See the *T2 Corporation Income Tax Guide* for more information.

T2 SCH 8 (06)

Canada

SCHEDULE 9

RELATED AND ASSOCIATED CORPORATIONS

Name of corporation	Business Number	Tax year end Year Month Day
Enersource Hydro Mississauga Inc.	88267 0920 RC0001	2006-12-31

This schedule is to be completed by a corporation having one or more of the following:

- related corporation(s)
- associated corporations(s)

	100 Name	200 Country of residence (if other than Canada)	300 Business Number (Canadian corporation only) (see note 1)	400 Relation- ship code (see note 2)	500 Number of common shares owned	550 % of common shares owned	600 Number of preferred shares owned	650 % of preferred shares owned	700 Book value of capital stock
1.	First Source Energy Corporation		89054 6211 RC0001	3					
2.	Enersource Telecom Inc.		88248 9610 RC0001	3					
3.	Enersource Hydro Mississauga Servi		88009 0212 RC0001	3					
4.	Enersource Corporation		89858 6417 RC0001	1					

Note 1: Enter "NR" if a corporation is not registered.

Note 2: Enter the code number of the relationship that applies from the following order: 1 -- Parent 2 -- Subsidiary 3 -- Associated 4 -- Related, but not associated.

T2 SCH 9(99)

Canada

CUMULATIVE ELIGIBLE CAPITAL DEDUCTION

Name of corporation Enersource Hydro Mississauga Inc.	Business Number 88267 0920 RC0001	Tax year end Year Month Day 2006-12-31

- For use by a corporation that has eligible capital property. For more information, see the *T2 Corporation Income Tax Guide*.
- A separate cumulative eligible capital account must be kept for each business.

Part 1 – Calculation of current year deduction and carry-forward

Cumulative eligible capital - Balance at the end of the preceding taxation year (if negative, enter "0")	200	<u>22,401,090</u>	A
Add:			
Cost of eligible capital property acquired during the taxation year	222	<u> </u>	
Other adjustments	226	<u> </u>	
Subtotal (line 222 plus line 226)		<u> </u>	
		$\times 3 / 4 =$	B
Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an eligible capital property to the corporation after December 20, 2002	228	<u> </u>	
		$\times 1 / 2 =$	C
amount B minus amount C (if negative, enter "0")		<u> </u>	D
Amount transferred on amalgamation or wind-up of subsidiary	224	<u> </u>	E
Subtotal (add amounts A, D, and E)	230	<u>22,401,090</u>	F
Deduct:			
Proceeds of sale (less outlays and expenses not otherwise deductible) from the disposition of all eligible capital property during the taxation year	242	<u> </u>	G
The gross amount of a reduction in respect of a forgiven debt obligation as provided for in subsection 80(7)	244	<u> </u>	H
Other adjustments	246	<u> </u>	I
		$(\text{add amounts G, H, and I}) \times 3 / 4 =$	J
Cumulative eligible capital balance (amount F minus amount J)		<u>22,401,090</u>	K
(if amount K is negative, enter "0" at line M and proceed to Part 2)			
Cumulative eligible capital for a property no longer owned after ceasing to carry on that business	249	<u> </u>	
amount K		<u>22,401,090</u>	
less amount from line 249		<u> </u>	
Current year deduction		<u>22,401,090</u> $\times 7.00 \% =$	
	250	<u>1,568,076</u>	*
(line 249 plus line 250) (enter this amount at line 405 of Schedule 1)		<u>1,568,076</u>	
		$\rightarrow$	L
Cumulative eligible capital - Closing balance (amount K minus amount L) (if negative, enter "0")	300	<u>20,833,014</u>	M

* You can claim any amount up to the maximum deduction of 7%. The deduction may not exceed the maximum amount prorated by the number of days in the taxation year divided by 365.

Amount from line K (show as positive amount)	_____	N
Total of cumulative eligible capital (CEC) deductions from income for taxation years beginning after June 30, 1988	400 _____	1
Total of all amounts which reduced CEC in the current or prior years under subsection 80(7)	401 _____	2
Total of CEC deductions claimed for taxation years beginning before July 1, 1988	402 _____	3
Negative balances in the CEC account that were included in income for taxation years beginning before July 1, 1988	403 _____	4
Line 3 minus line 4 (if negative, enter "0")	_____	5
Total of lines 1, 2 and 5	_____	6
Amounts included in income under paragraph 14(1)(b), as that paragraph applied to taxation years ending after June 30, 1988 and before February 28, 2000, to the extent that it is for an amount described at line 400	_____	7
Amounts at line T from Schedule 10 of previous taxation years ending after February 27, 2000	_____	8
Subtotal (line 7 plus line 8)	409 _____	9
Line 6 minus line 9 (if negative, enter "0")	_____	O
Line N minus line O (if negative, enter "0")	_____	P
Line P minus line Q (if negative, enter "0")	_____	Q
Line 5 _____ x 1 / 2 = _____	_____	R
Amount R _____ x 2 / 3 = _____	_____	S
Amount N or amount O, whichever is less	_____	T
Amount to be included in income (amount S plus amount T) (enter this amount on line 108 of Schedule 1)	410 _____	

Continuity of financial statement reserves (not deductible)

Financial statement reserves (not deductible)

	Description	Balance at the beginning of the year	Transfer on amalgamation or wind-up of subsidiary	Add	Deduct	Balance at the end of the year
1	Retirees Benefit Liability	2,140,123		442,877		2,583,000
2	Provision for Bad Debt			1,496,952		1,496,952
3						
	Reserves from Part 2 of Schedule 13					
	Totals	2,140,123		1,939,829		4,079,952

The total opening balance plus the total transfers should be entered on line 414 of Schedule 1 as a deduction.
The total closing balance should be entered on line 126 of Schedule 1 as an addition.

AGREEMENT AMONG ASSOCIATED CANADIAN-CONTROLLED PRIVATE CORPORATIONS TO ALLOCATE THE BUSINESS LIMIT

- For use by a Canadian-controlled private corporation (CCPC) to identify all associated corporations and to assign a percentage for each associated corporation. This percentage will be used to allocate the business limit for purposes of the small business deduction. Information from this schedule will also be used to determine the date the balance of tax is due and to calculate the reduction to the business limit.

- An associated CCPC that has more than one tax year ending in a calendar year, is required to file an agreement for each tax year ending in that calendar year.

Column 1: Enter the legal name of each of the corporations in the associated group. Include non-CCPCs and CCPCs that have filed an election under subsection 256(2) of the *Income Tax Act* (ITA) not to be associated for purposes of the small business deduction.

Column 2: Provide the Business Number for each corporation (if a corporation is not registered, enter "NR").

Column 3: Enter the association code that applies to each corporation:

- 1 - Associated for purposes of allocating the business limit (unless code 5 applies)
- 2 - CCPC that is a "third corporation" that has elected under subsection 256(2) not to be associated for purposes of the small business deduction
- 3 - Non-CCPC that is a "third corporation" as defined in subsection 256(2)
- 4 - Associated non-CCPC
- 5 - Associated CCPC to which code 1 does not apply because of a subsection 256(2) election made by a "third corporation"

Column 4: Enter the business limit for the year of each corporation in the associated group. The business limit is computed at line 4 on page 4 of each respective corporation's T2 return.

Column 5: Assign a percentage to allocate the business limit to each corporation that has an association code 1 in column 3. The total of all percentages in column 5 cannot exceed 100%.

Column 6: Enter the business limit allocated to each corporation by multiplying the amount in column 4 by the percentage in column 5. Add all business limits allocated in column 6 and enter the total at line A. Ensure that the total at line A falls within the range for the calendar year to which the agreement applies:

Calendar year	Acceptable range
2004	\$225,001 to \$250,000
2005	\$250,001 to \$300,000
2006	maximum \$300,000
2007	\$300,001 to \$400,000

If the calendar year to which this agreement applies is after 2007, ensure that the total at line A does not exceed \$400,000.

Allocating the business limit

Date filed (do not use this area) **025** Year Month Day

Enter the calendar year to which the agreement applies **050** Year 2006

Is this an amended agreement for the above-noted calendar year that is intended to replace an agreement previously filed by any of the associated corporations listed below? **075** 1 Yes ☐ 2 No ☒

1 Names of associated corporations	2 Business Number of associated corporations	3 Asso- ciation code	4 Business limit for the year (before the allocation) \$	5 Percentage of the business limit %	6 Business limit allocated* \$
100	200	300		350	400
1 Enersource Hydro Mississauga Inc.	88267 0920 RC0001	1	300,000	100.0000	300,000
2 First Source Energy Corporation	89054 6211 RC0001	1	300,000		
3 Enersource Telecom Inc.	88248 9610 RC0001	1	300,000		
4 Enersource Hydro Mississauga Services Inc.	88009 0212 RC0001	1	300,000		
5 Enersource Corporation	89858 6417 RC0001	1	300,000		
Total				100.0000	300,000 A

Business limit reduction under subsection 125(5.1) of the ITA

The business limit reduction is calculated in the small business deduction area of the T2 return. One of the factors used in this calculation is the "Large corporation amount" at line 415 of the T2 return. If the corporation is a member of an associated group** of corporations in the current tax year, the amount at line 415 of the T2 return is equal to $0.225\% \times (A - \$10,000,000)$ where, "A" is the total of taxable capital employed in Canada*** of each corporation in the associated group for its last tax year ending in the preceding calendar year.

*Each corporation will enter on line 410 of the T2 return, the amount allocated to it in column 6. However, if the corporation's tax year is less than 51 weeks, prorate the amount in column 6 by the number of days in the tax year divided by 365, and enter the result on line 410 of the T2 return.

Special rules apply if a CCPC has more than one tax year ending in a calendar year and is associated in more than one of those years with another CCPC that has a tax year ending in the same calendar year. In this case, the business limit for the second (or subsequent) tax year(s) will be equal to the lesser of the business limit determined for the first tax year ending in the calendar year and the business limit determined for the second (or subsequent) tax year(s) ending in the same calendar year.

**The associated group includes the corporation filing this schedule and each corporation that has an "association code" of 1 or 4 in column 3.

***"Taxable capital employed in Canada" has the meaning assigned by subsection 181.2(1) or 181.3(1) or section 181.4 of the ITA.



INVESTMENT TAX CREDIT – CORPORATIONS

General information

- For use by a corporation that during a tax year:
 - earned an investment tax credit (ITC);
 - is claiming a deduction against its Part I tax payable;
 - is claiming a refund of credit earned during the current tax year;
 - is claiming a carryforward of credit from preceding tax years;
 - is transferring a credit following an amalgamation or wind-up of a subsidiary, as described under subsections 87(1) and 88(1) of the federal *Income Tax Act*;
 - is requesting a credit carryback; or
 - is subject to a recapture of ITC.
- References to parts, sections, and subsections on this schedule are from the federal *Income Tax Act* and the federal *Income Tax Regulations*. References to interpretation bulletins and information circulars are to the latest versions.
- The ITC is eligible for a three-year carryback (if not deductible in the year earned). It is also eligible for a ten-year carryforward for credits earned in tax years that end before 2006 and a twenty-year carryforward for credits earned in tax years that end after 2005.
- Investments or expenditures, as defined in subsection 127(9) and Part XLVI of the federal *Income Tax Regulations*, that earn the ITC are:
 - qualified property (Parts 4 to 7);
 - qualified expenditures that are part of the SR&ED qualified expenditure pool (Parts 8 to 17). Complete and file Form T661, *Claim for Scientific Research and Experimental Development (SR&ED) Carried out in Canada*;
 - pre-production mining expenditures (Parts 18 to 20); and
 - apprenticeship job creation expenditures (Parts 21 to 23).
- Attach a completed copy of this schedule with the *T2 Corporation Income Tax Return*.
- For more information on ITCs, see the section called "Investment Tax Credit" in the *T2 Corporation – Income Tax Guide*, Information Circular IC 78-4, *Investment Tax Credit Rates*, and its related Special Release. Also, see Interpretation Bulletin IT-151, *Scientific Research and Experimental Development Expenditures*.
- For information on SR&ED, see Interpretation Bulletin IT-151, *Scientific Research and Experimental Development Expenditures*; Information Circular 86-4, *Scientific Research and Experimental Development*; Pamphlet T4052, *An Introduction to the Scientific Research and Experimental Development Program*; and Guide T4088, *Claiming Scientific Research and Experimental Development* (guide to Form T661).

Detailed information

- For the purpose of this schedule, "investment" means:
The capital cost of the property (excluding amounts added by an election under section 21), determined without reference to subsections 13(7.1) and 13(7.4), minus the amount of any government assistance or non-government assistance that the corporation has received, is entitled to receive, or can reasonably be expected to receive for that property when it files the income tax return for the year in which the property was acquired.
- An ITC deducted or refunded in a tax year for a depreciable property, other than a depreciable property deductible under paragraph 37(1)(b), reduces the capital cost of that property in the next tax year. It also reduces the undepreciated capital cost of that class in the next tax year. An ITC for SR&ED deducted or refunded in a tax year will reduce the balance in the pool of deductible SR&ED expenditures and the adjusted cost base (ACB) of an interest in a partnership in the next tax year. An ITC from pre-production mining expenditures deducted in a tax year reduces the balance in the pool of deductible cumulative Canadian exploration expenses in the next tax year.
- Property acquired has to be "available for use" before a claim for an ITC can be made.
- Qualified expenditures for SR&ED and capital costs for a property qualifying for an ITC must be identified by the claimant on Form T661 and Schedule 31 no later than 12 months after the claimant's income tax return is due for the tax year in which the expenditures or capital costs were incurred.
- Partnership allocations – Subsection 127(8) provides for the allocation of the amount that may reasonably be considered to be a partner's share of the ITCs of the partnership at the end of the fiscal period of the partnership. An allocation of ITCs is generally considered to be the partner's reasonable share of the ITCs if it is made in the same proportion in which the partners have agreed to share any income or loss and if section 103 of the Act is not applicable for the agreement to share any income or loss. For more information, see Interpretation Bulletin IT-151. Special rules apply to specified and limited partners.
- For SR&ED expenditures made after February 22, 2005, the expression "in Canada" includes the "exclusive economic zone" (as defined in the *Oceans Act* to generally consist of an area that is within 200 nautical miles from the Canadian coastline), including the airspace, seabed and subsoil for that zone. For SR&ED expenditures made prior to February 23, 2005, the expression "in Canada" generally includes the 12 nautical mile territorial sea.

Name of corporation	Business Number	Tax year end Year Month Day
Enersource Hydro Mississauga Inc.	88267 0920 RC0001	2006-12-31

Part 1 – Investments, expenditures and percentages

Investments	Specified percentage
Qualified property acquired primarily for use in Newfoundland and Labrador, Prince Edward Island, Nova Scotia, New Brunswick, the Gaspé Peninsula, or a prescribed offshore region	10 %
Expenditures	
If you are a Canadian-controlled private corporation (CCPC) throughout the tax year, this percentage may apply to you on the portion that you claim of the SR&ED qualified expenditure pool that does not exceed your expenditure limit (see Part 10)	35 %
Note: If your current year's qualified expenditures are more than the corporation's expenditure limit (see Part 10), the excess is eligible for an ITC calculated at the 20 % rate.	
If you are a corporation that is not a CCPC throughout the current tax year that incurred qualified expenditures for SR&ED in any area in Canada after 1995	20 %
If you are a taxable Canadian corporation that incurred pre-production mining expenditures:	
• in 2003	5 %
• in 2004	7 %
• after 2004	10 %
If you paid salary and wages to apprentices in the first 24 months of their apprenticeship contract for employment after May 1, 2006	10 %

Part 2 – Determination of a qualifying corporation

Is the corporation a qualifying corporation? **101** 1 Yes ☐ 2 No ☒

For the purpose of a refundable ITC, a **qualifying corporation** is defined under subsection 127.1(2). The corporation has to be a CCPC throughout the current tax year and the taxable income (before any loss carrybacks) for its preceding year cannot be more than its business limit for that preceding year. If the corporation is associated with any other corporations during the tax year, the total of the taxable incomes of the corporation and the associated corporations (before any loss carrybacks), for their last tax year ending in the preceding calendar year, cannot be more than the total of their business limits for that last year.

Note: A CCPC calculating a refundable ITC for tax years ending before March 23, 2004, is considered to be associated with another corporation if it meets any of the conditions in subsection 256(1). For tax years ending after March 22, 2004, the association rule remains the same except where:

- one corporation is associated with another corporation solely because one or more persons own shares of the capital stock of both corporations; and
- one of the corporations has at least one shareholder who is not common to both corporations.

If you are a **qualifying corporation**, you will earn a 100% refund on your share of any ITCs earned at the 35% rate on qualified current expenditures for SR&ED, up to the allocated expenditure limit. The 100% refund does not apply to qualified capital expenditures eligible for the 35% credit rate. They are only eligible for the 40% refund.

Some CCPCs that are not qualifying corporations may also earn a 100% refund on their share of any ITCs earned at the 35% rate on qualified current expenditures for SR&ED, up to the allocated expenditure limit. The expenditure limit can be determined in Part 10. The 100% refund does not apply to qualified capital expenditures eligible for the 35% credit rate. They are only eligible for the 40% refund.

The 100% refund will not be available to a corporation that is an **excluded corporation** as defined under subsection 127.1(2). A corporation is an excluded corporation if, at any time during the year, it is a corporation that is either controlled by (directly or indirectly, in any manner whatever) or is related to:

- one or more persons exempt from Part I tax under section 149;
- Her Majesty in right of a province, a Canadian municipality, or any other public authority; or
- any combination of persons referred to in a) or b) above.

Part 3 – Corporations in the farming industry

Complete this area if the corporation is making SR&ED contributions

Is the corporation claiming a contribution in the current year to an agricultural organization whose goal is to finance SR&ED work (for example, check-off dues)?

102 1 Yes ☐ 2 No ☒

If Yes, complete Schedule 125, *Income Statement Information*, to identify the type of farming industry the corporation is involved in. For more information on Schedule 125, see the *Guide to the General Index of Financial Information (GIFI) for Corporations*.

QUALIFIED PROPERTY

Part 4 – Eligible investments for qualified property from the current tax year

CCA* class number	Description of investment	Date available for use	Location used (province)	Amount of investment
105	110	115	120	125

*CCA: capital cost allowance

Total investment – enter in formula on line 240 in Part 5

Part 5 – Calculation of current-year credit and account balances – ITC from investments in qualified property

ITC at the end of the preceding tax year

Deduct:

Credit deemed as a remittance of co-op corporations

210

Credit expired*

215

Subtotal

220

ITC at the beginning of the tax year

Add:

Credit transferred on amalgamation or wind-up of subsidiary

230

ITC from repayment of assistance

235

Total current-year credit: total of column 125

x

10 % =

240

Credit allocated from a partnership

250

Subtotal

Total credit available

Deduct:

Credit deducted from Part I tax (enter on line EEE in Part 24)

260

Credit carried back to the preceding year(s) (from Part 6)

A

Credit transferred to offset Part VII tax liability

280

Subtotal

Credit balance before refund

Deduct:

Refund of credit claimed on investments from qualified property (from Part 7)

310

ITC closing balance of investments from qualified property

320

* The credit expires after 10 tax years if it was earned in a tax year ending before 2006 and after 20 tax years if it was earned in a tax year ending after 2005.

Part 6 – Request for carryback of credit from investments in qualified property

1st preceding tax year

2nd preceding tax year

3rd preceding tax year

Year	Month	Day

Credit to be applied

901

Credit to be applied

902

Credit to be applied

903

Total (enter on line A in Part 5)

Part 7 – Calculation of refund for qualifying corporations on investments from qualified property

Current-year ITCs (total of lines 240 and 250 in Part 5)

Credit balance before refund (amount B from Part 5)

Refund (40 % of amount C or D, whichever is less)

Enter amount E or a lesser amount on line 310 in Part 5 (also enter it on line 780 of the T2 return if the corporation does not claim an SR&ED ITC refund).

C

D

E

Name of corporation	Business Number	Tax year end Year Month Day
Enersource Hydro Mississauga Inc.	88267 0920 RC0001	2006-12-31

SR&ED

Part 8 – Qualified expenditures for SR&ED

Current expenditures	350
Capital expenditures	360
Repayments made in the year (from line 560 on Form T661)	370
Total (this must equal the amount from line 570 on Form T661)	380

Part 9 – Components of the SR&ED expenditure limit calculation

Part 9 only applies if the corporation was a CCPC throughout the current tax year.

Note: A CCPC that calculates SR&ED expenditure limit for tax years ending before March 23, 2004, is considered to be associated with another corporation if it meets any of the conditions in subsection 256(1). This also applies for tax years ending after March 22, 2004, except where:

- one corporation is associated with another corporation solely because one or more persons own shares of the capital stock of the corporation; and
- one of the corporations has at least one shareholder who is not common to both corporations.

Is the corporation associated with another CCPC for the purpose of calculating the SR&ED expenditure limit?

385 1 Yes ☒ 2 No ☐

Complete lines 390 and 395 if you answered No to the question at line 385 above or if the corporation is not associated with any other corporations (the amounts for associated corporations will be determined on Schedule 49).

- a) Enter your taxable income for the preceding tax year* 390
- b) Enter your reduced business limit** for the current tax year* (this amount cannot be more than the amount at line 4 on page 4 of the T2 return) 395

* If either of the tax years referred to at line 390 or 395 is less than 51 weeks, multiply the taxable income or the business limit by the following result: 365 divided by the number of days in these tax years. For details on the expression "Reduced business limit," see line 652 of the T2 Corporation – Income Tax Guide.

** If the corporation is claiming only a portion of the business limit from line 4 on page 4 of the T2 return because of its association with other corporations, calculate your reduced business limit as if the corporation was not associated in the current tax year. Enter the result at line 395.

Part 10 – Calculation of SR&ED expenditure limit for a CCPC throughout the current tax year

For stand-alone corporations:

Subtract: line 390 from Part 9 or \$400,000*, whichever is more $\times 10 =$

Excess (if negative, enter "0") F

Line F $\times$ Line 395 $=$ **G
Line 4 on page 4 of the T2 return

For associated corporations:

If associated, the allocation of the SR&ED expenditure limit as provided on Schedule 49 400 **H

Where the tax year of the corporation is less than 51 weeks, calculate the amount of the expenditure limit as follows:

Line G or H $\times$ Number of days in the tax year $\frac{365}{365} =$ I

Your SR&ED expenditure limit for the year (enter the amount from line G, H, or I, whichever applies) 410

* If your tax year immediately follows a tax year that ended before 2007, the references to \$6,000,000 and \$400,000 should be \$5,000,000 and \$300,000 respectively.

** Amount G or H cannot be more than \$2,000,000.

Part 11 – Calculation of investment tax credits on SR&ED expenditures

Enter whichever is less: current expenditures (line 350 from Part 8) or the expenditure limit (line 410 from Part 10)*

Line 350 minus line 410 (if negative, enter "0")

Line 410 minus line 350 (if negative, enter "0")

Enter whichever is less: capital expenditures (line 360 from Part 8) or line L above*

Line 360 minus line L (if negative, enter "0")

Repayments (amount from line 370 in Part 8)

If a corporation makes a repayment of any government assistance, non-government assistance, or contract payments that reduced the amount of qualified expenditures for ITC purposes, the amount of the repayment is eligible for a credit at the rate that would have applied to the repaid amount.

420	x	35 %	=	J
430	x	20 %	=	K
	L			
440	x	35 %	=	M
450	x	20 %	=	N
460	x	35 %	=	
470	x	30 %	=	
480	x	20 %	=	
		Total	=	O

Current-year SR&ED ITC (total of lines J, K, M, N, and O; enter on line 540 in Part 12)

* For corporations that are not CCPCs throughout the year, enter "0" on lines J and M.

Part 12 – Calculation of current-year credit and account balances – ITC from SR&ED expenditures

ITC at the end of the preceding tax year

Deduct:

Credit deemed as a remittance of co-op corporations

Credit expired*

510	
515	
Subtotal	520

ITC at the beginning of the tax year

Add:

Credit transferred on amalgamation or wind-up of subsidiary

Total current-year credit

Credit allocated from a partnership

530	
540	
550	
Subtotal	

Total credit available

Deduct:

Credit deducted from Part I tax (enter on line FFF in Part 24)

Credit carried back to the preceding year(s) (from Part 13)

Credit transferred to offset Part VII tax liability

560	
	P
580	
Subtotal	

Credit balance before refund

Deduct:

Refund of credit claimed on expenditures of SR&ED (from Part 14 or 15, whichever applies)

610

ITC closing balance on SR&ED

620

* The credit expires after 10 tax years if it was earned in a tax year ending before 2006 and after 20 tax years if it was earned in a tax year ending after 2005.

Part 13 – Request for carryback of credit from SR&ED expenditures

1st preceding tax year

2nd preceding tax year

3rd preceding tax year

Year	Month	Day

Credit to be applied

911

Credit to be applied

912

Credit to be applied

913

Total (enter on line P in Part 12)

Name of corporation	Business Number	Tax year end Year Month Day
Enersource Hydro Mississauga Inc.	88267 0920 RC0001	2006-12-31

Part 14 – Calculation of refund of ITC for qualifying corporations – SR&ED

Complete this part only if you are a qualifying corporation as determined at line 101.

Is the corporation an excluded corporation as defined under subsection 127.1(2)? **650** 1 Yes ☐ 2 No ☒

Credit balance before refund (amount Q from Part 12) R

Current-year ITC (lines 540 plus 550 from Part 12 minus line O from Part 11) S

Refundable credits (amount R or S, whichever is less)* T

Amount J from Part 11 U

Subtract: Amount T or U, whichever is less V

Net amount (if negative, enter "0") W

Amount W x 40 % X

Add: Amount V Y

Refund of ITC (amounts X plus Y – enter this, or a lesser amount, on line 610 in Part 12) Z

Enter the total of lines 310 from Part 5 and 610 from Part 12 on line 780 of the T2 return.

* If you are also an excluded corporation [as defined in subsection 127.1(2)], this amount should be multiplied by 40%.
Claim this, or a lesser amount, as your refund of ITC on line Z.

Part 15 – Calculation of refund of ITC for CCPCs that are not qualifying or excluded corporations – SR&ED

Complete this box only if you are a CCPC that is not a qualifying or excluded corporation as determined in Part 2.

Credit balance before refund (amount Q from Part 12) AA

Amount J from Part 11 BB

Subtract: Amount AA or BB, whichever is less CC

Net amount (if negative, enter "0") DD

Amount M from Part 11 EE

Amount DD or EE, whichever is less x 40 % FF

Add : Amount CC above GG

Refund of ITC (amounts FF plus GG) HH

Enter HH, or a lesser amount, on line 610 in Part 12 and also on line 780 of the T2 return.

RECAPTURE - SR&ED

Part 16 - Calculating the recapture of ITC for corporations and corporate partnerships - SR&ED

You will have a recapture of ITC in a year when all of the following conditions are met:

- you acquired a particular property in the current year or in any of the 10 preceding tax years, if the credit was earned in a tax year ending before 2006, or in any of the 20 preceding tax years, if the credit was earned in a tax year ending after 2005;
- you claimed the cost of the property as a qualified expenditure for SR&ED on Form T661;
- the cost of the property was included in calculating your ITC or was the subject of an agreement made under subsection 127(13) to transfer qualified expenditures; and
- you disposed of the property or converted it to commercial use after February 23, 1998. This condition is also met if you disposed of or converted to commercial use a property that incorporates the particular property previously referred to.

Note

The recapture does not apply if you disposed of the property to a non-arm's length purchaser who intended to use it all or substantially all for SR&ED. When the non-arm's length purchaser later sells or converts the property to commercial use, the recapture rules will apply to the purchaser based on the historical ITC rate of the original user.

You will report a recapture on the T2 return for the year in which you disposed of the property or converted it to commercial use. In the following tax year, add the amount of the ITC recapture to the SR&ED expenditure pool.

If you have more than one disposition for calculations 1 and 2, complete the columns for each disposition for which a recapture applies, using the calculation formats below.

Calculation 1 - If you meet all of the above conditions

Amount of ITC you originally calculated for the property you acquired, or the original user's ITC where you acquired the property from a non-arm's length party, as described in the note above 700	Amount calculated using ITC rate at the date of acquisition (or the original user's date of acquisition) on either the proceeds of disposition (if sold in an arm's length transaction) or the fair market value of the property (in any other case) 710	Amount from column 700 or 710, whichever is less
1.		

Subtotal (enter this amount on line LL in Part 17)

Calculation 2 - Only if you acquired all or a part of the qualified expenditure from another person under an agreement described in subsection 127(13); otherwise, enter nil at line JJ in Part 16.

A The rate percentage that the transferee used in determining its ITC for qualified expenditures under a subsection 127(13) agreement 720	B The proceeds of disposition of the property if you dispose of it to an arm's length person; or, in any other case, enter the fair market value of the property at conversion or disposition 730	C The amount, if any, already provided for in Calculation 1 (This allows for the situation where only part of the cost of a property is transferred under a subsection 127(13) agreement.) 740

Name of corporation Enersource Hydro Mississauga Inc.	Business Number 88267 0920 RC0001	Tax year end Year Month Day 2006-12-31

Part 16 – Calculating the recapture of ITC for corporations and corporate partnerships – SR&ED (continued)

Calculation 2 (continued) – Only if you acquired all or a part of the qualified expenditure from another person under an agreement described in subsection 127(13); otherwise, enter nil on line JJ below.

D The amount determined by the formula (A x B) - C	E The ITC earned by the transferee for the qualified expenditures that were transferred	F Amount from column D or E, whichever is less
	750	

Subtotal (enter this amount on line MM in Part 17) **750** JJ

Calculation 3

As a member of the partnership, you will report your share of the ITC of the partnership after the ITC has been reduced by the amount of the recapture. If this amount is a positive amount, you will report it on line 550 in Part 12. However, if the partnership does not have sufficient ITC otherwise available to offset the recapture, then the amount by which reductions to ITC exceed additions (the excess) will be determined and reported on line KK below.

Corporate partner's share of the excess of ITC (amount to be reported on line NN in Part 17) **760** KK

Part 17 – Total recapture of investment tax credit

Recaptured ITC for calculation 1 from line II in Part 16	LL
Recaptured ITC for calculation 2 from line JJ in Part 16 above	MM
Recaptured ITC for calculation 3 from line KK in Part 16 above	NN
Total recapture of investment tax credit – Add lines LL, MM and NN (Enter amount OO at line 602 of the T2 return.)	OO

PRE-PRODUCTION MINING

Part 18 – Pre-production mining expenditures

Exploration information

A mineral resource that qualifies for the credit means a mineral deposit from which the principal mineral to be extracted is diamond, a base or precious metal deposit, or a mineral deposit from which the principal mineral to be extracted is an industrial mineral that, when refined, results in a base or precious metal.

In column 800, list all minerals for which pre-production mining expenditures have taken place in the tax year and after 2002.

List of minerals
800

For each of the minerals reported in column 800 above, identify each project, mineral title, and mining division where title is registered. If there were no mineral title, identify the project and mining division only.

Project name	Mineral title	Mining division
805	806	807

Pre-production mining expenditures *

Pre-production mining expenditures that the corporation incurred in the tax year and after 2002, for the purpose of determining the existence, location, extent, or quality of a mineral resource in Canada:

Prospecting	810	PP
Geological, geophysical, or geochemical surveys	811	QQ
Drilling by rotary, diamond, percussion, or other methods	812	RR
Trenching, digging test pits, and preliminary sampling	813	SS

Pre-production mining expenditures incurred in the tax year and after 2002 for bringing a new mine in a mineral resource in Canada into production in reasonable commercial quantities and incurred before the new mine comes into production in such quantities:

Clearing, removing overburden, and stripping	820	TT
Sinking a mine shaft, constructing an adit, or other underground entry	821	UU

Other pre-production mining expenditures incurred in the tax year and after 2002:

Description	Amount
825	826

Add amounts at column 826 **826** **827** **828** **829** **830** **831** **832** **833** **834** **835** **836** **837** **838** **839** **840** **841** **842** **843** **844** **845** **846** **847** **848** **849** **850** **851** **852** **853** **854** **855** **856** **857** **858** **859** **860** **861** **862** **863** **864** **865** **866** **867** **868** **869** **870** **871** **872** **873** **874** **875** **876** **877** **878** **879** **880** **881** **882** **883** **884** **885** **886** **887** **888** **889** **890** **891** **892** **893** **894** **895** **896** **897** **898** **899** **900** **901** **902** **903** **904** **905** **906** **907** **908** **909** **910** **911** **912** **913** **914** **915** **916** **917** **918** **919** **920** **921** **922** **923** **924** **925** **926** **927** **928** **929** **930** **931** **932** **933** **934** **935** **936** **937** **938** **939** **940** **941** **942** **943** **944** **945** **946** **947** **948** **949** **950** **951** **952** **953** **954** **955** **956** **957** **958** **959** **960** **961** **962** **963** **964** **965** **966** **967** **968** **969** **970** **971** **972** **973** **974** **975** **976** **977** **978** **979** **980** **981** **982** **983** **984** **985** **986** **987** **988** **989** **990** **991** **992** **993** **994** **995** **996** **997** **998** **999** **1000**

Total pre-production mining expenditures (add amounts PP to VV) **830**

Deduct: Total of all assistance (grants, subsidies, rebates, and forgivable loans) or reimbursements that the corporation has received or is entitled to receive in respect of the amounts referred to at line 830 above **832**

Excess (line 830 minus line 832) (if negative, enter "0") **833**

Add: Repayments of government and non-government assistance **835**

Pre-production mining expenditures (amount WW plus amount XX) **836**

* A pre-production mining expenditure is defined under subsection 127(9) and does not include an amount renounced under subsection 66(12.6).

Name of corporation Enersource Hydro Mississauga Inc.	Business Number 88267 0920 RC0001	Tax year end Year Month Day 2006-12-31

Part 19 – Calculation of current-year credit and account balances – ITC from pre-production mining expenditures

ITC at the end of the preceding tax year

Deduct:

Credit deemed as a remittance of co-op corporations **841**

Credit expired* **845**

Subtotal **850**

ITC at the beginning of the tax year

Add:

Credit transferred on amalgamation or wind-up of subsidiary **860**

Expenditures from line YY, Part 18,
incurred in 2003 **865** x 5 % = ... ZZ

Expenditures from line YY, Part 18,
incurred in 2004 **867** x 7 % = ... AAA

Expenditures from line YY, Part 18,
incurred after 2004 **870** x 10 % = ... BBB

Total current-year credit (add amounts
ZZ, AAA, and BBB) **880**

Total credit available

Deduct:

Credit deducted from Part I tax (enter on line GGG in Part 24) **885**

Credit carried back to the preceding year(s) (from Part 20) CCC

Subtotal **890**

ITC closing balance from pre-production mining expenditures

* The credit expires after 10 tax years if it was earned in a tax year ending before 2006 and after 20 tax years if it was earned in a tax year ending after 2005.

Part 20 – Request for carryback of credit from pre-production mining expenditures

	Year	Month	Day		
1st preceding tax year				Credit to be applied	921
2nd preceding tax year				Credit to be applied	922
3rd preceding tax year				Credit to be applied	923
Total (enter on line CCC in Part 19)					

APPRENTICESHIP JOB CREATION

Part 21 – Calculation of total current-year credit – ITC from apprenticeship job creation expenditures

If you are a related person as defined under subsection 251(2), has it been agreed in writing that you are the only employer who will be claiming the apprenticeship job creation tax credit for this tax year for each apprentice whose contract number (or social insurance number or name) appears below? (If not, you cannot claim the tax credit.)

611 1 Yes ☒ 2 No ☐

For each apprentice in their first 24 months of the apprenticeship, enter the apprenticeship contract number registered with Canada, or a province or territory, under an apprenticeship program designed to certify or license individuals in the trade. If there is no contract number, enter the social insurance number (SIN) or the name of the eligible apprentice. Also enter the name of the eligible trade, the eligible salary and wages* payable for employment after May 1, 2006, and 10% of this amount. Then enter the lesser of 10% of eligible salary and wages or \$2,000.

A Contract number (SIN or name of apprentice)	B Name of eligible trade	C Eligible salary and wages*	D Column C x 10 %	E Lesser of column D or \$ 2,000
601	602	603	604	605
1.	Daryl Vanherk	15,199	1,520	1,520
2.	Brandon Bones	15,262	1,526	1,526
3.	Greg Smth	15,199	1,520	1,520
4.				
Total current-year credit (enter at line 640)				4,566

* Net of any other government or non-government assistance received or to be received.

Part 22 – Calculation of current-year credit and account balances – ITC from apprenticeship job creation expenditures

ITC at the end of the preceding tax year

Deduct:

Credit deemed as a remittance of co-op corporations

Credit expired after 20 tax years

612

615

Subtotal

ITC at the beginning of the tax year

625

Add:

Credit transferred on amalgamation or wind-up of subsidiary

ITC from repayment of assistance

Total current-year credit (total of column 605)

Credit allocated from a partnership

630

635

640

655

Subtotal

Total credit available

4,566

4,566

4,566

Deduct:

Credit deducted from Part I tax (enter on line HHH in Part 24)

Credit carried back to the preceding year(s) (from Part 23)

660

4,566

DDD

Subtotal

4,566

4,566

ITC closing balance from apprenticeship job creation expenditures

690

Part 23 – Request for carryback of credit from apprenticeship job creation expenditures

1st preceding tax year

2nd preceding tax year

3rd preceding tax year

Year	Month	Day

Credit to be applied

931

Credit to be applied

932

Credit to be applied

933

Total (enter on line DDD in Part 22)

Investment tax credit for child care spaces

Calculation of current-year credit – ITC from child care space creation expenditures

	A Eligible expenditures for child care spaces	B Column A x 25.00 %	C Lesser of column B or \$ 10,000
1.			
Total current-year credit			

Calculation of current-year credit and account balances – ITC from child care space creation expenditures

ITC at the end of the preceding tax year

Deduct:

Credit deemed as a remittance of co-op corporations

Credit expired after 20 tax years

Subtotal

ITC at the beginning of the tax year

Add:

Credit transferred on amalgamation or wind-up of subsidiary

ITC from repayment of assistance

Total current-year credit (total of column C)

Credit allocated from a partnership

Subtotal

Total credit available

Deduct:

Credit deducted from Part I tax (enter on line HHH.1 in Part 24)

Credit carried back to the preceding year(s)

Subtotal

ITC closing balance for child care space creation expenditures

Request for carryback of credit from child care space creation expenditures

	Year	Month	Day	
1st preceding tax year	2005	12	31	Credit to be applied
2nd preceding tax year	2004	12	31	Credit to be applied
3rd preceding tax year	2003	12	31	Credit to be applied
				Total

Part 24 – Total ITC deducted from Part I tax

ITC from investments in qualified property deducted from Part I tax (from line 260 in Part 5)	EEE
ITC from SR&ED expenditures deducted from Part I tax (from line 560 in Part 12)	FFF
ITC from pre-production mining expenditures deducted from Part I tax (from line 885 in Part 19)	GGG
ITC from apprenticeship job creation expenditures deducted from Part I tax (from line 660 in Part 22)	4,566 HHH
ITC from child care space creation expenditures deducted from Part I tax	HHH.1
Total ITC deducted from Part I tax (add lines EEE, FFF, GGG, HHH and HHH.1)	4,566 III

(Enter amount III at line 652 of the T2 return.)

Summary of Investment Tax Credit Carryovers

Continuity of investment tax credit carryovers

CCA class no.: 97

Current year

Addition current year (A)	Applied current year (B)	Claimed as a refund (C)	Carried back (D)	ITC end of year (A-B-C-D)
4,566	4,566			

Prior years

Taxation year	ITC beginning of year (E)	Adjustments (F)	Applied current year (G)	ITC expired (H) See Note	ITC end of year (E-F-G-H) See Note
1st prior year					
2nd prior year					
3rd prior year					
4th prior year					
5th prior year					
6th prior year					
7th prior year					
8th prior year					
9th prior year					
10th prior year					
Total					

Total ITC utilized (B+C+D+G) 4,566

Note : The ITC end of year includes the amount of ITC expired from the 10th preceding year that is in column (H). Note that this credit expires only at the beginning of the subsequent fiscal period. Consequently, this amount will be posted on line 215, 515, 615, 845 or on the line *Credit expired* for the child care space creation, as applicable, of Schedule 31 for the subsequent period.



Canada Revenue Agency
Agence du revenu
du Canada

SCHEDULE 33

PART I.3 TAX ON LARGE CORPORATIONS

Name of corporation	Business Number	Tax year-end Year Month Day
Enersource Hydro Mississauga Inc.	88267 0920 RC0001	2006-12-31

- File this schedule if the total taxable capital employed in Canada of the corporation (other than a financial institution or an insurance corporation) and its related corporations is greater than \$10,000,000.
- Even if there is no Part I.3 tax payable for the days in the tax year that are after 2005, you must still complete this schedule (except parts 5 and 9).
- Parts, sections, subsections, and paragraphs referred to on this schedule are from the *Income Tax Act* and the *Income Tax Regulations*.
- Subsection 181(1) defines the terms "financial institution," "long-term debt," and "reserves."
- Subsection 181(3) provides the basis to determine the carrying value of a corporation's assets or any other amount under Part I.3 for its capital, investment allowance, taxable capital, or taxable capital employed in Canada, or for a partnership in which it has an interest.
- No Part I.3 tax is payable for a taxation year by a corporation that was:
 - bankrupt [as defined by subsection 128(3)] at the end of the year;
 - a deposit insurance corporation throughout the year, as defined by subsection 137.1(5), or deemed to be a deposit insurance corporation by subsection 137.1(5.1);
 - exempt from tax under section 149 throughout the year on all of its taxable income;
 - neither resident in Canada nor carrying on a business through a permanent establishment in Canada at any time in the year; or
 - a corporation described in subsection 136(2) throughout the year, the principal business of which was marketing (including any related processing) natural products belonging to or acquired from its members or customers.
- File the completed Schedule 33 with the *T2 Corporation Income Tax Return* no later than six months from the end of the tax year.
- This schedule may contain changes that had not yet become law at the time of printing.

If the corporation was a non-resident of Canada throughout the year and carried on a business through a permanent establishment in Canada, go to Part 4, "Taxable capital employed in Canada."

Part 1 - Capital

Add the following amounts at the end of the year:

Reserves that have not been deducted in computing income for the year under Part I	101	2,583,000
Capital stock (or members' contributions if incorporated without share capital)	103	155,629,000
Retained earnings	104	27,136,000
Contributed surplus	105	
Any other surpluses	106	
Deferred unrealized foreign exchange gains	107	
All loans and advances to the corporation	108	25,816,000
All indebtedness of the corporation represented by bonds, debentures, notes, mortgages, hypothecary claims, bankers' acceptances, or similar obligations	109	290,000,000
Any dividends declared but not paid by the corporation before the end of the year	110	
All other indebtedness of the corporation (other than any indebtedness for a lease) that has been outstanding for more than 365 days before the end of the year	111	
Proportion of the amount, if any, by which the total of all amounts (see note below) for the partnership of which the corporation is a member at the end of the year exceeds the amount of the partnership's deferred unrealized foreign exchange losses	112	

Subtotal 501,164,000 501,164,000 A

Deduct the following amounts:

Deferred tax debit balance at the end of the year	121	
Any deficit deducted in computing its shareholders' equity (including, for this purpose, the amount of any provision for the redemption of preferred shares) at the end of the year	122	
Any amount deducted under subsection 135(1) in computing income under Part I for the year, as long as the amount may reasonably be regarded as being included in any of lines 101 to 112 above	123	
The amount of deferred unrealized foreign exchange losses at the end of the year	124	

Subtotal 501,164,000 B

Capital for the year (amount A minus amount B) (if negative, enter "0") 190 501,164,000

Note: Lines 101, 107, 108, 109, 111, and 112 are determined as follows:

- If the partnership is a member of another partnership (tiered partnerships), include the amounts of the partnership and tiered partnerships.
- Amounts for the partnership and tiered partnerships are those that would be determined for lines 101, 107, 108, 109, 111, and 112 as if they apply in the same way that they apply to corporations.
- Do not include amounts owing to the member or to other corporations that are members of the partnership.
- Amounts are determined at the end of the last fiscal period of the partnership ending in the year of the corporation.
- The proportion of the total amounts is determined by the corporation's share of the partnership's income or loss for the fiscal period of the partnership.

Part 2 – Investment allowance

Add the carrying value at the end of the year of the following assets of the corporation:

A share of another corporation	401	
A loan or advance to another corporation (other than a financial institution)	402	1,352,000
A bond, debenture, note, mortgage, hypothecary claim, or similar obligation of another corporation (other than a financial institution)	403	
Long-term debt of a financial institution	404	
A dividend receivable on a share of the capital stock of another corporation	405	
A loan or advance to, or a bond, debenture, note, mortgage, hypothecary claim, or similar obligation of, a partnership all of the members of which, throughout the year, were other corporations (other than financial institutions) that were not exempt from tax under Part 1.3 [other than by reason of paragraph 181.1(3)(d)]	406	
An interest in a partnership (see note 1 below)	407	
Investment allowance for the year (add lines 401 to 407)	490	1,352,000

Notes:

- Where the corporation has an interest in a partnership or in tiered partnerships, consider the following:
 - the investment allowance of a partnership is deemed to be the amount calculated at line 490 above, at the end of its fiscal period, as if it was a corporation;
 - the total of the carrying value of each asset of the partnership described in the above lines is for its last fiscal period ending at or before the end of the corporation's tax year; and
 - the carrying value of a partnership member's interest at the end of the year is its specified proportion [as defined in subsection 248(1)] of the partnership's investment allowance.
- Lines 401 to 405 should not include the carrying value of a share of the capital stock of, a dividend payable by, or indebtedness of a corporation that is exempt from tax under Part 1.3 [other than by reason of paragraph 181.1(3)(d)].
- Where a trust is used as a conduit for loaning money from a corporation to another related corporation (other than a financial institution), the loan will be considered to have been made directly from the lending corporation to the borrowing corporation, according to subsection 181.2(6).

Part 3 – Taxable capital

Capital for the year (line 190)	501,164,000	C
Deduct: Investment allowance for the year (line 490)	1,352,000	D
Taxable capital for the year (amount C minus amount D) (if negative, enter "0")	500	499,812,000

Part 4 – Taxable capital employed in Canada

To be completed by a corporation that was resident in Canada at any time in the year

Taxable capital for the year (line 500)	499,812,000	x	Taxable income earned in Canada	610	28,493,430	=	Taxable capital employed in Canada	690	499,812,000
			Taxable income		28,493,430				

- Notes:
- Regulation 8601 gives details on calculating the amount of taxable income earned in Canada.
 - Where a corporation's taxable income for a tax year is "0," it shall, for the purposes of the above calculation, be deemed to have a taxable income for that year of \$1,000.
 - In the case of an airline corporation, Regulation 8601 should be considered when completing the above calculation.

To be completed by a corporation that was a non-resident of Canada throughout the year and carried on a business through a permanent establishment in Canada

Total of all amounts each of which is the carrying value at the end of the year of an asset of the corporation used in the year or held in the year, in the course of carrying on any business it carried on during the year through a permanent establishment in Canada	701	
Deduct the following amounts:		
Corporation's indebtedness at the end of the year [other than indebtedness described in any of paragraphs 181.2(3)(c) to (f)] that may reasonably be regarded as relating to a business it carried on during the year through a permanent establishment in Canada	711	
Total of all amounts each of which is the carrying value at the end of year of an asset described in subsection 181.2(4) of the corporation that it used in the year, or held in the year, in the course of carrying on any business during the year through a permanent establishment in Canada	712	
Total of all amounts each of which is the carrying value at the end of year of an asset of the corporation that is a ship or aircraft the corporation operated in international traffic, or personal or movable property used or held by the corporation in carrying on any business during the year through a permanent establishment in Canada (see note below)	713	
Total deductions (add lines 711, 712, and 713)		E
Taxable capital employed in Canada (line 701 minus amount E) (if negative, enter "0")	790	

Note: Complete line 713 only if the country in which the corporation is resident did not impose a capital tax for the year on similar assets, or a tax for the year on the income from the operation of a ship or aircraft in international traffic, of any corporation resident in Canada during the year.

Part 5 – Calculation of gross Part 1.3 tax

If the tax year starts after 2005, do not complete this part.

Taxable capital employed in Canada (line 690 or 790, whichever applies) 499,812,000

Deduct: Capital deduction claimed for the year (enter \$50,000,000 or, for related corporations, the amount allocated on Schedule 36) **801** 50,000,000

Excess of taxable capital employed in Canada over capital deduction **811** 449,812,000

Line 811 449,812,000 x Number of days in the tax year in 2004 x 0.002 = ... F
365

Line 811 449,812,000 x Number of days in the tax year in 2005 x 0.00175 = ... G
365

Note: The Part 1.3 tax rate is reduced to 0% for the days in the tax year that are after 2005.

Subtotal (add amounts F and G) H

Where the tax year of a corporation is less than 51 weeks, calculate the amount of gross Part 1.3 tax as follows:

Amount H x Number of days in the year (365) = ... I
365

Gross Part 1.3 tax (amount H or I, whichever applies) **820**

Part 6 – Calculation of gross Part 1.3 tax for purposes of the unused surtax credit

Taxable capital employed in Canada (line 690 or 790, whichever applies) 499,812,000 J

Deduct: Line 801 above 50,000,000 x 1/5 = ... 10,000,000 K

Excess (amount J minus amount K) (if negative, enter "0") 489,812,000 L

Amount L 489,812,000 x 0.00225 = ... 1,102,077 M

Where the tax year of a corporation is less than 51 weeks, calculate the amount of gross Part 1.3 tax for purposes of the unused surtax credit as follows:

Amount M 1,102,077 x Number of days in the year (365) = ... N
365

Gross Part 1.3 tax for purposes of the unused surtax credit (amount M or N, whichever applies) **821** 1,102,077

Part 7 – Calculation of current-year surtax credit available

- Corporations can claim a credit against their Part 1.3 tax for the amount of Canadian surtax payable for the year. This is called the surtax credit.
- Any unused surtax credit can be carried back three years or carried forward seven years. Unused surtax credits must be applied in order of the oldest first.
- Refer to subsection 181.1(7) when calculating the amount deductible for a corporation's unused surtax credits where control of the corporation has been acquired between the year in which the credits arose and the year in which you want to claim them.

For a corporation that was a non-resident of Canada throughout the year, enter amount a or b at line O, whichever is less:

a) line 600 from the T2 return a
b) line 700 from the T2 return b O

In any other case, enter amount c or d at line P, whichever is less:

c) line 600 from the T2 return $\frac{319,126}{\text{line 690 of this schedule}} \times \frac{\text{line 690 of this schedule}}{\text{line 500 of this schedule}} = \frac{499,812,000}{499,812,000} = 319,126$ c
d) line 700 from the T2 return 6,298,180 d 319,126 P

Current-year surtax credit available (amount O or P, whichever applies) **830** 319,126

Part 8 – Calculation of current-year unused surtax credit

Current-year surtax credit available (line 830) 319,126
Less: Gross Part 1.3 tax for purposes of the unused surtax credit (line 821) 1,102,077
Current-year unused surtax credit (if negative, enter "0") **850**
Enter this amount at line 600 on Schedule 37.

Part 9 – Calculation of net Part 1.3 tax payable

If the tax year starts after 2005, do not complete this part.

Gross Part 1.3 tax (line 820) Q
Deduct:
Current-year surtax credit applied (line 820 or 830, whichever is less) **861**
Unused surtax credit from previous years applied (amount from line 320 on Schedule 37) **862**
Subtotal (cannot be more than amount on line 820) R
Net Part 1.3 tax payable (amount Q minus amount R) **870**
Enter this amount at line 704 of the T2 return.

Part 10 – Calculation for purposes of the small business deduction

This part is applicable only to corporations that are not associated in the current year, but were associated in the prior year.

Taxable capital employed in Canada (line 690 or 790, whichever applies) S
Deduct:
Capital deduction claimed for the year (enter \$10,000,000) T
Excess (amount S minus amount T) (if negative, enter "0") U
Gross Part 1.3 tax for purposes of the small business deduction (Amount U x 0.00225) V
Enter this amount at line 415 of the T2 return

Attached Schedule with Total

Part 1 – All loans and advances to the corporation

Title Line 108: All loans and advances

Description

		Amount
Due to Related Parties		2,372,000 00
Sub-division advances		1,704,000 00
Consumer Deposits		21,740,000 00
Total		25,816,000 00

Page 1 of 1

AGREEMENT AMONG RELATED CORPORATIONS – PART 1.3 TAX

- Members of a related group of corporations should use this schedule to allocate the capital deduction of \$50,000,000 among the members of the related group. Do not file this agreement if no members of the related group have to pay Part 1.3 tax.
- In cases where a related corporation has more than one taxation year ending in a calendar year, it has to file an agreement for each of those taxation years.
- A corporation that is related to any other corporation at any time in a taxation year of the corporation that ends in a calendar year may file such an agreement.
- In accordance with subsection 181.5(7) of the federal *Income Tax Act*, a Canadian-controlled private corporation is not considered to be related to another corporation for purposes of the capital deduction unless it is also associated with that corporation.

Agreement

Date filed (do not use this area) **010** Year Month Day

Is this an amended agreement? **020** 1 Yes ☐ 2 No ☒

Calendar year to which the agreement applies **030** Year 2006

Note: This agreement must include all the information indicated below for all members of the related group, including members to which no amount of capital deduction is allocated for the year. However, any member that is exempt from Part 1.3 tax under subsection 181.1(3) does not have to be included.

Names of all corporations which are members of the related group 200	Business Number (if a corporation is not registered, enter "NR") 300	Allocation of capital deduction for the year \$ 400	Taxation year end to which this agreement applies* (YYYY/MM/DD) 500
1 Enersource Hydro Mississauga Inc.	88267 0920 RC0001	50,000,000	
2 First Source Energy Corporation	89054 6211 RC0001		
3 Enersource Telecom Inc.	88248 9610 RC0001		
4 Enersource Hydro Mississauga Services Inc.	88009 0212 RC0001		
5 Enersource Corporation	89858 6417 RC0001		

Total (cannot be more than \$50,000,000) **50,000,000**

- * Entries are only required in this column for a corporation that has more than one taxation year ending in the same calendar year and is related in two or more of those taxation years to another corporation that has a taxation year ending in that calendar year. The capital deduction of the first corporation for each such taxation year at the end of which it is related to the other corporation is an amount equal to its capital deduction for the first such taxation year. Enter the taxation year end to which this agreement applies.

SHAREHOLDER INFORMATION

Name of corporation	Business Number	Tax year end Year Month Day
Enersource Hydro Mississauga Inc.	88267 0920 RC0001	2006-12-31

All private corporations must complete this schedule for any shareholder who holds 10% or more of the corporation's common and/or preferred shares.

Provide only one number per shareholder						
Name of shareholder (after name, indicate in brackets if the shareholder is a corporation, partnership, individual, or trust)		Business Number	Social insurance number	Trust number	Percentage common shares	Percentage preferred shares
100		200	300	350	400	500
1	ENERSOURCE CORPORATION	89858 6417 RC0001			100.000	
2						
3						
4						
5						
6						
7						
8						
9						
10						

GENERAL RATE INCOME POOL (GRIP) CALCULATION

Name of corporation Enersource Hydro Mississauga Inc.	Business Number 88267 0920 RC0001	Tax year-end Year Month Day 2006-12-31

On: 2006-12-31

- If you are a Canadian-controlled private corporation (CCPC) or a deposit insurance corporation (DIC), use this schedule to determine the general rate income pool (GRIP).
- When an eligible dividend was paid in the tax year, file a completed copy of this schedule with your *T2 Corporation Income Tax Return*. Do not send your worksheets with your return, but keep them in your records in case we ask to see them later.
- Subsections referred to in this schedule are from the *Income Tax Act*.
- Subsection 89(1) defines the terms eligible dividend, excessive eligible dividend designation, general rate income pool, and low rate income pool.

Eligibility for the various additions

Answer the following questions to determine the corporation's eligibility for the various additions:

2006 addition

1. Is this the corporation's first taxation year that includes January 1, 2006? ☒ Yes ☐ No
2. If not, what is the date of the taxation year end of the corporation's first year that includes January 1, 2006?
3. If yes, during that first year, was the corporation a CCPC or would it have been a CCPC if not for the election of subsection 89(11) ITA? ☒ Yes ☐ No
- If the answer to question 3 is yes, complete Part 5.

Change in the type of corporation

4. Was the corporation a CCPC during its preceding taxation year? ☒ Yes ☐ No
5. Corporations that become a CCPC or a DIC ☐ Yes ☒ No
- If the answer to question 5 is yes, complete Part 4.

Amalgamation

6. Corporations that were formed as a result of an amalgamation ☐ Yes ☒ No
- If the answer to question 6 is yes, answer questions 7 and 8. If the answer is no, go to question 9.
7. Was one or more of the predecessor corporations neither a CCPC nor a DIC? ☐ Yes ☐ No
- If the answer to question 7 is yes, complete Part 4.
8. Was one or more of the predecessor corporation a CCPC or a DIC during the taxation year that ended immediately before amalgamation? ☐ Yes ☐ No
- If the answer to question 8 is yes, complete Part 3.

Winding-up

9. Corporations that wound-up a subsidiary ☐ Yes ☒ No
- If the answer to question 9 is yes, answer questions 10 and 11. If the answer is no, go to Part 1.
10. Was the subsidiary neither a CCPC nor a DIC during its last taxation year? ☐ Yes ☐ No
- If the answer to question 10 is yes, complete Part 4.
11. Was the subsidiary a CCPC or a DIC during its last taxation year? ☐ Yes ☐ No
- If the answer to question 11 is yes, complete Part 3.

Part 1 – Calculation of general rate income pool (GRIP)

If the corporation's tax year includes January 1, 2006, complete "Part 5 – GRIP addition for 2006" and then line 050. Otherwise, complete line 100.

GRIP addition for 2006 (the greater of amount QQ from Part 5 or "0")	050	7,900,672	A
GRIP at the end of the previous tax year	100		B
Taxable income for the year (DITs enter "0")*	110	28,493,430	C
Income for the credit union deduction* (amount E in Part 3 of Schedule 17)	120		
Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less*	130		
For a CCPC, the lesser of aggregate investment income (line 440 of the T2 return) and taxable income*	140		
Subtotal (add lines 120, 130, and 140)			D
Income taxable at the general corporate rate (line C minus line D)	150	28,493,430	
After-tax income (line 150 multiplied by 68 %)	190	19,375,532	E
Eligible dividends received in the tax year	200		
Dividends deductible under section 113 received in the tax year	210		
Subtotal (add lines 200 and 210)			F
GRIP addition:			
Becoming a CCPC (line PP from Part 4)	220		
Post-amalgamation (total of lines EE from Part 3 and lines PP from Part 4)	230		
Post-wind-up (total of lines EE from Part 3 and lines PP from Part 4)	240		
Subtotal (add lines 220, 230, and 240)			G
Subtotal (add lines A or B (as applicable), E, F, and G)		27,276,204	H
Eligible dividends paid in the previous tax year	300		
Excessive eligible dividend designations made in the previous tax year	310		
Note: If becoming a CCPC (subsection 89(4) applies), enter "0" on lines 300 and 310.			
Subtotal (line 300 minus line 310)			I
GRIP before adjustment for specified future tax consequences (line H minus line I) (amount can be negative)	490	27,276,204	
Total GRIP adjustment for specified future tax consequences to previous tax years (amount Y from Part 2)	560		
GRIP at the end of the year (line 490 minus line 560)	590	27,276,204	
Enter this amount on line 160 on Schedule 55.			

* Note: For lines 110, 120, 130, and 140, the income amount is the amount before considering specified future tax consequences. This phrase is defined in subsection 248(1). It includes the deduction of a loss carryback from subsequent tax years, a reduction of Canadian exploration expenses and Canadian development expenses that were renounced in subsequent tax years (e.g., flow-through share renunciations), reversals of income inclusions where an option is exercised in subsequent tax years, and the effect of certain foreign tax credit adjustments.

Part 2 – GRIP adjustment for specified future tax consequences to previous tax years

Complete this part if the corporation's taxable income of any of the previous three tax years took into account the specified future tax consequences defined in subsection 248(1) from the current tax year. Otherwise, enter "0" on line 560 of page 1 or leave it blank.

First previous tax year	2005-12-31
Taxable income before specified future tax consequences from the current tax year	22,531,225 J1
Enter the following amounts before specified future tax consequences from the current tax year:	
Income for the credit union deduction (amount E in Part 3 of Schedule 17)	K1
Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less	L1
Aggregate investment income (line 440 of the T2 return)	M1
Subtotal (add lines K1, L1, and M1)	O1
Subtotal (line J1 minus line O1) (if negative, enter "0")	22,531,225 P1

Part 2 – GRIP adjustment for specified future tax consequences to previous tax years (continued)

Future tax consequences that occur for the current year					
Amount carried back from the current year to a prior year					
Non-capital loss carry-back (paragraph 111 (1)(a) ITA)	Capital loss carry-back	Restricted farm loss carry-back	Farm loss carry-back	Other	Total carrybacks

Taxable income after specified future tax consequences Q1

Enter the following amounts after specified future tax consequences:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) ... R1

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less S1

Aggregate investment income (line 440 of the T2 return) T1

Subtotal (add lines R1, S1, and T1) V1

Subtotal (line Q1 minus line V1) (if negative, enter "0") W1

Subtotal (line P1 minus line W1) (if negative, enter "0") X1

GRIP adjustment for specified future tax consequences to first previous tax year (line X1 multiplied by 68 %) ... **500**

Second previous tax year 2004-12-31

Taxable income before specified future tax consequences from the current tax year J2

Enter the following amounts before specified future tax consequences from the current tax year:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) ... K2

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less L2

Aggregate investment income (line 440 of the T2 return) M2

Accelerated tax reduction (line 637 of T2 return)* multiplied by 100/7 N2

Subtotal (add lines K2, L2, M2, and N2) O2

Subtotal (line J2 minus line O2) (if negative, enter "0") P2

Future tax consequences that occur for the current year					
Amount carried back from the current year to a prior year					
Non-capital loss carry-back (paragraph 111 (1)(a) ITA)	Capital loss carry-back	Restricted farm loss carry-back	Farm loss carry-back	Other	Total carrybacks

Taxable income after specified future tax consequences Q2

Enter the following amounts after specified future tax consequences:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) ... R2

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less S2

Aggregate investment income (line 440 of the T2 return) T2

Accelerated tax reduction (line 637 of T2 return)* multiplied by 100/7 U2

Subtotal (add lines R2, S2, T2, and U2) V2

Subtotal (line Q2 minus line V2) (if negative, enter "0") W2

Subtotal (line P2 minus line W2) (if negative, enter "0") X2

GRIP adjustment for specified future tax consequences to second previous tax year (line X2 multiplied by 68 %) ... **520**

Part 2 – GRIP adjustment for specified future tax consequences to previous tax years (continued)

Third previous tax year 2003-12-31

Taxable income before specified future tax consequences from the current tax year

Enter the following amounts before specified future tax consequences from the current tax year: J3

Income for the credit union deduction

(amount E in Part 3 of Schedule 17) K3

Amount on line 400, 405, 410, or 425

of the T2 return, whichever is less L3

Aggregate investment income

(line 440 of the T2 return) M3

Accelerated tax reduction (line 637 of

T2 return)* multiplied by 100/7 N3

Subtotal (add lines K3, L3, M3, and N3)

O3

Subtotal (line J3 minus line O3) (if negative, enter "0")

P3

Future tax consequences that occur for the current year

Amount carried back from the current year to a prior year

Non-capital loss carry-back (paragraph 111 (1)(a) ITA)	Capital loss carry-back	Restricted farm loss carry-back	Farm loss carry-back	Other	Total carrybacks

Taxable income after specified future tax consequences

Q3

Enter the following amounts after specified future tax consequences:

Income for the credit union deduction

(amount E in Part 3 of Schedule 17) R3

Amount on line 400, 405, 410, or 425

of the T2 return, whichever is less S3

Aggregate investment income

(line 440 of the T2 return) T3

Accelerated tax reduction (line 637 of

T2 return)* multiplied by 100/7 U3

Subtotal (add lines R3, S3, T3, and U3)

V3

Subtotal (line Q3 minus line V3) (if negative, enter "0")

W3

Subtotal (line P3 minus line W3) (if negative, enter "0")

X3

GRIP adjustment for specified future tax consequences to third previous tax year (line X3 multiplied by

68 %) 540

Total GRIP adjustment for specified future tax consequences to previous tax years:

(add lines 500, 520, and 540) (if negative, enter "0")

Enter amount Y on line 560.

Y

*Note: The accelerated tax reduction was available for 2001 to 2004 tax years.

Part 3 – Worksheet to calculate the GRIP addition post-amalgamation or post-wind-up (predecessor or subsidiary was a CCPC or DIC in its last tax year)

nb. 1 Post amalgamation ☐ Post wind-up ☐

Complete this part when there has been an amalgamation (within the meaning assigned by subsection 87(1)) or a wind-up (to which subsection 88(1) applies) and the predecessor or subsidiary corporation was a CCPC or DIC in its last tax year. In the calculation below, corporation means a predecessor or a subsidiary. The last tax year for a predecessor corporation was its tax year that ended immediately before the amalgamation and for a subsidiary corporation was its tax year during which its assets were distributed to the parent on the wind-up.

For a post-wind-up, include the GRIP addition in calculating the parent's GRIP at the end of its tax year that immediately follows the tax year during which it receives the assets of the subsidiary.

Complete a separate worksheet for each predecessor and each subsidiary that was a CCPC or DIC in its last tax year. Keep a copy of this calculation for your records, in case we ask to see it later.

Corporation's GRIP at the end of its last tax year

AA

Eligible dividends paid by the corporation in its last tax year

BB

Excessive eligible dividend designations made by the corporation in its last tax year

CC

Subtotal (line BB minus line CC)

DD

GRIP addition post-amalgamation or post-wind-up (predecessor or subsidiary was a CCPC or DIC in its last tax year)

(line AA minus line DD)

EE

After you complete this calculation for each predecessor and each subsidiary, calculate the total of all the EE lines. Enter this total amount on:

— line 230 for post-amalgamation; or

— line 240 for post-wind-up.

Part 4 – Worksheet to calculate the GRIP addition post-amalgamation, post-wind-up (predecessor or subsidiary was not a CCPC or DIC in its last tax year), or the corporation is becoming a CCPC

nb. 1 Corporation becoming a CCPC ☐ Post amalgamation ☐ Post wind-up ☐

Complete this part when there has been an amalgamation (within the meaning assigned by subsection 87(1)) or a wind-up (to which subsection 88(1) applies) and the predecessor or subsidiary was not a CCPC or DIC in its last tax year. Also, use this part for a corporation becoming a CCPC. In the calculation below, corporation means a corporation becoming a CCPC, a predecessor, or a subsidiary.

For a post-wind-up, include the GRIP addition in calculating the parent's GRIP at the end of its tax year that immediately follows the tax year during which it receives the assets of the subsidiary.

Complete a separate worksheet for each predecessor and each subsidiary that was not a CCPC or a DIC in its last tax year. Keep a copy of this calculation for your records, in case we ask to see it later.

Cost amount to the corporation of all property immediately before the end of its previous/last tax year FF

The corporation's money on hand immediately before the end of its previous/last tax year GG

Unused and unexpired losses at the end of the corporation's previous/last tax year:

Non-capital losses

Net capital losses

Farm losses

Restricted farm losses

Limited partnership losses

Subtotal HH

Subtotal (add lines FF, GG, and HH) II

All the corporation's debts and other obligations to pay that were outstanding immediately before the end of its previous/last tax year JJ

Paid up capital of all the corporation's issued and outstanding shares of capital stock immediately before the end of its previous/last tax year KK

All the corporation's reserves deducted in its previous/last tax year LL

The corporation's capital dividend account immediately before the end of its previous/last tax year MM

The corporation's low rate income pool immediately before the end of its previous/last tax year NN

Subtotal (add lines JJ, KK, LL, MM, and NN) OO

GRIP addition post-amalgamation or post-wind-up (predecessor or subsidiary was not a CCPC or DIC in its last tax year), or the corporation is becoming a CCPC (line II minus line OO) (if negative, enter "0") PP

After you complete this worksheet for each predecessor and each subsidiary, calculate the total of all the PP lines. Enter this total amount on:

- line 220 for a corporation becoming a CCPC;
- line 230 for post-amalgamation; or
- line 240 for post-wind-up.

Part 5 – GRIP addition for 2006

Use this part to calculate the GRIP balance for a corporation that was a CCPC, or would have been but for an election under subsection 89(11), throughout its tax year that includes January 1, 2006.

	Tax years ending in				
	2001	2002	2003	2004	2005
1. Taxable income for the year*					22,531,225
2. Income for manufacturing and processing profits deduction* (lesser of amount V and Y in Part 9 of Schedule 27)				NIL	NIL
3. Income for manufacturing and processing profits deduction – electrical energy, steam* (amount QQ in Part 13 of Schedule 27)				NIL	NIL
4. Taxable resource income* (line 435 of the T2 return)					
5. Income for the credit union deduction* (amount E in Part 3 of Schedule 17)					
6. Income for the small business deduction* (amount on line 400, 405, 410, and 425 of the T2 return, whichever is less)					
7. Aggregate investment income* (line 440 of the T2 return)					
8. Income for the accelerated tax reduction* (line 637 of the T2 return multiplied by 100/7)					NIL
9. Subtotal (add rows 2 through 8)					
10. Full rate taxable income before specified future tax consequences (row 1 minus row 9) (if negative, enter "0")					22,531,225
11. Multiply row 10 by 63.00 %					14,194,672
12. Dividends deductible under subsection 112(1) received from connected corporations, that are reasonably considered, to have been paid out of full rate taxable income in respect of the payer corporation	941	942	943	944	945
13. Subtotal (add row 11 and row 12)					14,194,672
14. Total taxable dividends paid by the corporation (greater of amounts on line 460 and line 500 on Schedule 3)					6,294,000
15. GRIP addition (row 13 minus row 14) (if negative, enter "0")	951	952	953	954	955
					7,900,672

GRIP addition for 2006 (add lines 951, 952, 953, 954, and 955) 7,900,672 QQ
Enter the greater of amount QQ or "0" on line 050.

* Note: For rows 1 to 8, all income amounts are before considering the specified future tax consequences for that tax year.

PART III.1 TAX ON EXCESSIVE ELIGIBLE DIVIDEND DESIGNATIONS

Name of corporation Enersource Hydro Mississauga Inc.	Business Number 88267 0920 RC0001	Tax year-end Year Month Day 2006-12-31

Do not use this area

- Every corporation resident in Canada that pays a taxable dividend (other than a capital gains dividend within the meaning assigned by subsection 130.1(4) or 131(1)) in the tax year must file this schedule.
- Canadian-controlled private corporations (CCPC) and deposit insurance corporations (DIC) must complete Part 1. All other corporations must complete Part 2.
- Every corporation that has paid an eligible dividend must also file Schedule 53, *General Rate Income Pool (GRIP) Calculation*, or Schedule 54, *Low Rate Income Pool Calculation (LRIP)*; whichever is applicable.
- File the completed schedules with your *T2 Corporation Income Tax Return* no later than six months from the end of the tax year.
- Parts, subsections, and paragraphs mentioned in this schedule refer to the *Income Tax Act*.
- Subsection 89(1) defines the terms eligible dividend, excessive eligible dividend designation, general rate income pool (GRIP), and low rate income pool (LRIP).
- The calculations in Part 1 and Part 2 do not apply if the excessive eligible dividend designation arises from the application of paragraph (c) of the definition of excessive eligible dividend designation in subsection 89(1). This paragraph applies when an eligible dividend is paid to artificially maintain or increase the GRIP or to artificially maintain or decrease the LRIP.

Part 1 – Canadian-controlled private corporations and deposit insurance corporations

Taxable dividends paid in the tax year not included in Schedule 3	
Taxable dividends paid in the tax year included in Schedule 3	8,900,000
Total taxable dividends paid in the tax year	100 8,900,000
Total eligible dividends paid in the tax year	150
GRIP at the end of the year (line 590 on Schedule 53) (if negative, enter "0")	160 27,276,204
Excessive eligible dividend designation (line 150 minus line 160)	A
Part III.1 tax on excessive eligible dividend designations – CCPC or DIC (line A multiplied by 20%)	x 20 % 190

Part 2 – Other corporations

Taxable dividends paid in the tax year not included in Schedule 3	
Taxable dividends paid in the tax year included in Schedule 3	
Total taxable dividends paid in the tax year	200
Total excessive eligible dividend designations in the tax year (line A of Schedule 54)	B
Part III.1 tax on excessive eligible dividend designations – Other corporations (line B multiplied by 20%)	x 20 % 290



Sudbury ON P3A 5C1

Page 1 of 6

ENERSOURCE HYDRO MISSISSAUGA
INC
ATTEN ENERSOURCE HYDRO MISSISS
3240 MAVIS ROAD
MISSISSAUGA ON L5C 3K1

Date of mailing	September 27, 2007
Business Number	88267 0920 RC0002
Taxation year-end	December 31, 2006

00007

CORPORATION NOTICE OF ASSESSMENT

RESULTS

This notice explains the results of our assessment of the T2 Corporation Income Tax Return for the taxation year indicated above. It also explains any changes we may have made to the return.

Result of this Assessment :	\$	0.00
Prior balance:	\$	0.00
	=====	
Total balance:	\$	0.00

Please refer to the Summary and Explanation for additional information.

ENERSOURCE HYDRO MISSISSAUGA INC

Page 2 of 6

Date of mailing	September 27, 2007
Business Number	88267 0920 RC0002
Taxation year-end	December 31, 2006

CORPORATION NOTICE OF ASSESSMENT

SUMMARY OF ASSESSMENT

	\$ Reported	\$ Assessed
Federal Tax:		
Part I	0.00	0.00
Part I.3	0.00	0.00
Part II	0.00	0.00
Part IV	0.00	0.00
Part IV.1	0.00	0.00
Part VI	0.00	0.00
Part VI.1	0.00	0.00
Part XIII.1	0.00	0.00
Part XIV	0.00	0.00
		=====
Total Federal Tax:		\$ 0.00
		=====
Net balance:	\$	0.00
		=====
Result of this assessment:	\$	0.00
Prior balance:	\$	0.00
		=====
Total balance:	\$	0.00

William V. Baker
Commissioner of Revenue

EXPLANATION

We have revised the net income or loss for tax purposes to agree with the calculated amount.

We have revised the reduced business limit for the purpose of the small business deduction to correct a mathematical error.

Please visit our Web site at www.cra.gc.ca/requests-business for information about online requests available to business clients. This service allows clients to electronically request certain financial actions, additional remittance vouchers and other communication products, as well as reproductions of previously issued correspondence.

The Canada Revenue Agency also offers the convenience of Direct Deposit. For information about this service, please visit our Web site at www.cra.gc.ca or contact the number provided below.

Did you know you may be eligible to file your return using our Corporation Internet Filing service? For information on eligibility criteria and the service in general, please visit www.cra.gc.ca/corporation-internet.



ENERSOURCE HYDRO MISSISSAUGA INC

Page 3 of 6

Date of mailing
September 27, 2007
Business Number
88267 0920 RC0002
Taxation year-end
December 31, 2006

00007

CORPORATION NOTICE OF ASSESSMENT

If you require additional information or wish to request an adjustment, contact:

Sudbury Tax Centre
1050 Notre Dame Ave
Sudbury ON P3A 5C1
Phone 1-800-959-5525
Fax (705) 671-0490
Toll free number 1-800-959-5525
We accept collect calls.

Toronto West Services Office
P.O. Box 6000 5800 Hurontario St.
Mississauga ON L5A 4E9
Toll free number 1-800-959-5525

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ENERSOURCE HYDRO MISSISSAUGA INC

Page 4 of 6

Date of mailing	September 27, 2007
Business Number	88267 0920 RC0002
Taxation year-end	December 31, 2006

CORPORATION NOTICE OF ASSESSMENT

Any reference to the term "reporting period" on this notice has the same meaning as the term "taxation year." Both terms describe the period assessed. The term "taxation year" is defined in the *Income Tax Act*.

We calculate interest at rates prescribed by regulations.

LP FOR PEOPLE WHO ARE DEAF

If you are deaf and have access to a Telephone Device for the Deaf (TDD), you can call toll-free for explanations and information about the corporation's tax return. This bilingual service is available year-round from Monday to Friday (except for statutory holidays). You can phone 1-800-665-0354 between 8:15 a.m. and 5:00 p.m. Eastern Time. When calling, please take into account any time zone differences.

FILING AN OBJECTION

If you do not agree with this assessment, you can file an objection. You can do this by sending either a letter or Form T400A, *Objection*, to the Chief of Appeals at your tax services office or tax centre.

You have to file an objection within 90 days of the day we mailed the *Notice of Assessment*.

For a large corporation (as defined in subsection 225.1(8) of the *Income Tax Act*), the notice of objection shall:

- reasonably describe each issue;
- specify the relief you are seeking, expressed as an amount of a change in balance (as defined in subsection 152(4.4) of the *Income Tax Act*) or a balance of undeducted outlays, expenses, or other amounts of the corporation; and
- provide facts and reasons the corporation relied on for each issue.

DETERMINING THE CORPORATION'S LOSSES

If you do not agree with the amount of loss ascertained, you can write to your tax services office requesting a determination of the loss. However, we will only issue a *Notice of Determination/Redetermination of a Loss* if the loss reported is revised at the initial assessing stage or as a result of a reassessment arising from an audit or other investigative action by the Department.

NORMAL REASSESSMENT PERIOD

This may be the only notice the corporation will receive for this taxation year. However, we may reassess a T2 return if an error is brought to our attention or if we find an error during our post-assessing reviews. Generally, we will only reassess a T2 return within the "normal reassessment period." The normal reassessment period begins on the date of mailing the original *Notice of Assessment* or notification that no tax is payable. The period ends:

- three years from this date if the corporation is a Canadian-controlled private corporation; and
- four years from this date for all other corporations.

EXTENSIONS TO THE NORMAL REASSESSMENT PERIOD

We may also reassess a T2 return for a particular taxation year:

1. within one year after all rights of objection and appeal have expired for a preceding taxation year if:
 - the result of an assessment or a decision on an appeal will change the balance (as defined in subsection 152(4.4) of the *Income Tax Act*) of the preceding taxation year, and
 - the reassessment to the particular year is related to the balance adjusted in the preceding year.
2. within three years after the end of the normal reassessment period if:
 - you are carrying back a loss or credit from a later taxation year;
 - a non-arm's length transaction between the corporation and a non-resident affects the corporation's tax;
 - the corporation paid an amount or received a refund of foreign income or profits tax;
 - another taxpayer's reassessment for any of the above reasons affects the corporation's tax; or
 - another taxation year's reassessment (has to be a prior taxation year if the reassessment relates to a loss or credit carry-back) for any of the above reasons affects the corporation's tax.

however, we may reassess a T2 return for a taxation year at **any time** if:

the person filing the return has made any misrepresentation that is attributable to neglect, carelessness, or wilful default, or has committed any fraud in filing the return or in supplying any information; or

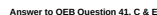
the person filing the return has filed Form T2029, *Waiver in Respect of the Normal Reassessment Period*, within that taxation year's normal reassessment period that has not been revoked.

Answer to OEB Question 41. B

**Enersource Hydro Mississauga
Reserves from Financial Statements
2008 Budget**

	(A)			(B)	(A)+(B)
	Retiree Bridge Benefits Accrual			Liability For Retirees Benefit	Reserves from FS
-Plan came into effect June 1/06					
Opening liability, December 31, 2006	Consolidated \$ 383,574	Hydro \$ 311,095	Opening liability, December 31, 2006	\$ 2,272,500	
<u>2007 Forecast</u>			<u>2007 Forecast</u>		
2007 net amortzation of transition obligation	\$ 166,900				
Plus service costs	\$ 137,900		Add current service cost	\$ 77,800	
Plus Interest on ABO	\$ 106,600		Add interest cost	\$ 130,600	
* \$ 411,400		\$ 333,665	Deduct current account premiums	\$ (72,000)	
Closing liability, Dec 31, 2007		\$ 644,760	Closing liability, Dec 31, 2007	\$ 2,408,900	\$ 3,053,660
<u>2008 Budget</u>			<u>2008 Budget</u>		
2008 net amortzation of transition obligation	\$ 166,900		Opening liability, December 31, 2007	\$ 2,408,900	
Plus service costs	\$ 137,900		Add current service cost	\$ 82,470	
Plus Interest on ABO	\$ 120,918		Add interest cost	\$ 126,467	
* \$ 425,718			Deduct current account premiums	\$ (74,160)	
		\$ 345,495	Closing liability, Dec 31, 2008	\$ 2,543,677	\$ 3,533,932
Closing liability, Dec 31, 2008		\$ 990,255			
<u>2009 Forecast</u>			<u>2009 Forecast</u>		
2009 net amortzation of transition obligation	\$ 166,900		Opening liability, December 31, 2008	\$ 2,543,677	
Plus service costs	\$ 137,900		Add current service cost	\$ 87,084	
Plus Interest on ABO	\$ 143,268		Add interest cost	\$ 133,543	
* \$ 448,068			Deduct current account premiums	\$ (76,385)	
		\$ 363,633	Closing liability, Dec 31, 2009	\$ 2,687,919	\$ 4,041,807
Closing liability, Dec 31, 2009		\$ 1,353,888			

* Total bridge benefits cost allocated based on company headcount.



For Fiscal 2008 forecast													
Class	Vehicle #	Opening UCC	UCC Additions	Disposals	Net Assets (Disp)	1/2 of Net Add/(Disp)	CCA Base	Rate (%)	CCA	Partial Yr Adjustment	Partial Yr CCA	Closing UCC	
COMPANY 10 - Hydro	1	349,362.555	-	-	-	-	349,362.555	4.0%	13,974.502	1.00000	13,974.502	335,388.053	
	2	42,272.671	-	-	-	-	42,272.671	6.0%	2,536.360	1.00000	2,536.360	39,736.310	
	8	12,295.090	4,308.418	-	4,308.418	2,154.209	14,449.299	20.0%	2,889.860	1.00000	2,889.860	13,713.648	
	10	7,150.964	1,823.400	-	1,823.400	911.700	8,072.664	20.0%	2,421.799	1.00000	2,421.799	6,562.364	
	10.1	017-04	10,058	-	-	-	10,058	30.0%	3,018	1.00000	3,018	7.041	
	10.1	019-04	10,058	-	-	-	10,058	30.0%	3,018	1.00000	3,018	7.041	
	10.1	020-04	14,033	-	-	-	14,033	30.0%	4,209	1.00000	4,209	12.046	
	10.1	016-04	10,058	-	-	-	10,058	30.0%	3,018	1.00000	3,018	7.041	
	10.1	007-05	10,058	-	-	-	10,058	30.0%	3,018	1.00000	3,018	7.041	
	10.1	018-05	10,058	-	-	-	10,058	30.0%	3,018	1.00000	3,018	7.041	
	10.1	020-07	49,419	34,200	-	34,200	66,519	30.0%	19,956	1.00000	19,956	63.663	
	10.1	021-05	10,058	-	-	-	10,058	30.0%	3,018	1.00000	3,018	7.041	
	10.1	022-05	14,369	-	-	-	14,369	30.0%	4,311	1.00000	4,311	10.058	
	10.1	023-05	14,369	-	-	-	14,369	30.0%	4,311	1.00000	4,311	10.058	
	10.1	520-04	14,369	-	-	-	14,369	30.0%	4,311	1.00000	4,311	10.058	
	10.1	521-06	14,369	-	-	-	14,369	30.0%	4,311	1.00000	4,311	10.058	
	10.1	522-06	14,369	-	-	-	14,369	30.0%	4,311	1.00000	4,311	10.058	
	45	2,765.000	4,986.874	-	4,986.874	4,729.437	7,494.437	45.0%	3,372.496	1.00000	3,372.496	8,851.377	
	47	7,536.546	33,500.000	-	33,500.000	16,750.000	50,696.547	8.0%	2,765.724	1.00000	2,765.724	53,462.320	
	98	6,588.925	-	-	720.000	720.000	-	6,588.925	0.0%	-	1.00000	-	6,588.925
	12	543.500	-	-	-	-	903.500	100.0%	903.500	1.00000	903.500	360.000	
	3	2,504.106	-	-	-	-	2,504.106	5.0%	125.205	1.00000	125.205	2,378.901	
												33,541.286	
CEC (7%)		19,374.703	-	-	-	-	19,374.703	7.0%	1,356.229	1.00000	1,356.229	18,018.474	

ENERSOURCE HYDRO MISSISSAUGA, INC
CAPITAL EXPENDITURES
YEARS 2007-2009

	ACCTG	ASSET	Uniformed		2007	2008	2009
	CLASS	ACCOUNT	Standard of Accounts	DESCRIPTION	Capitalizations	Capitalizations	Capitalizations
120020	1	120020.50 yrs	1808	BLDGS-BRCK			15,000,000
120060	47	120060.30 yrs	1820	MUN SUB EQ	2,875,000	3,425,000	3,400,000
120080	47	120080.15 yrs	1980	SUP CONT	1,370,000	1,400,000	1,400,000
120220	47	120220.25 yrs	1830	OH PRIMARY	12,406,717	9,200,000	9,300,000
120240	47	120240.25 yrs	1840	UG PRIMARY	19,175,000	19,475,000	19,750,000
					35,826,717	33,500,000	33,850,000
120400	8	120400.25 yrs	1860	METERS	1,611,345	1,033,895	3,487,500
120410	8	120410	1555	SMART METERS	1,114,896	974,523	
120440	8	120440	1915	GEN OFF EQ	2,110,000	2,150,000	2,000,000
120480	8	120480	1940	GARAGE EQP	613,000		
120500	8	120500	1940	MAJOR TOOLS & INSTR	150,000	150,000	150,000
					5,599,241	4,308,418	5,637,500
120460	10 & 10.1	120460.8 yrs	1930	ROLL STOCK	1,295,000	1,296,000	1,529,000
120460	10 & 10.1	120460.5 yrs	1930	ROLL STOCK	260,000	370,000	324,000
120460	10 & 10.1	120460.4 yrs	1930	ROLL STOCK	306,800	191,600	47,200
					1,861,800	1,857,600	1,900,200
120520	45	120520	1920	COMP EQUIP	2,395,000	9,458,874	1,495,000
120560	12	120560	1925	SOFTWARE	1,087,000	720,000	725,000
				TOTAL	46,769,758	49,844,892	43,607,700

Answer to OEB Question 41. F**Payments in Lieu of taxes**

PILS:	Test 2008 Excl PILs	Bridge 2007 Excl PILs
Net Income before interest Excluding PILs Revenue	\$ 35,674	\$ 26,910
Less: Interest Expenses for accounting purposes	17,479	16,680
Net Income/(Loss)	18,195	10,230
<u>Reconciliation of accounting income to taxable income</u>		
<u>Additions to net income</u>		
Provision for income taxes - current	\$ -	\$ -
Amortization of tangible assets	34,357	32,007
Recovery of deferred costs & amortization of regulatory assets	2,850	3,764
Recovery of RCVA	-	5
Reserves from Financial Statements (End of Year)	3,534	3,054
Capital tax expensed per accounts	1,482	1,450
Gain/(Loss) on Foreign Exchange	-	300
Other additions (Note 1)	468	467
Total additions	42,690	41,047
<u>Deductions from net income</u>		
Capital cost allowance	\$ 33,541	\$ 30,056
Cumulative Eligible capital deduction	1,356	1,458
Capital tax per CT23	1,482	1,450
Reserves from Financial Statements (Beginning of Year)	3,054	2,583
Deferred RCVA costs & interest income on regulated assets	87	116
AFUDC - Interest capitalized to Book	302	330
Other deductions (Note 2)	250	250
Total Deductions	40,072	36,245
Total Additions less Deductions	2,618	4,802
Taxable Income/(Loss)	\$ 20,813	\$ 15,032
Total Income tax (Before gross-up)	\$ 7,518	\$ 5,430
Total Income tax (Grossed-up for Rate Making)	\$ 11,768	\$ 8,500
Total Capital Taxes (including grossed-up LCT to 2006)	\$ 1,482	\$ 1,482
TOTAL INCOME & CAPITAL TAXES	\$ 13,250	\$ 9,982

SHEET 1 - Regulatory Assets - Continuity Schedule

NAME OF UTILITY	Enersource Hydro Mississauga	LICENCE NUMBER	ED-2003-0017
NAME OF CONTACT	John Bonadie	DOCID NUMBER	EB-2007-0706
E-mail Address	bonadie@enersource.com		
VERSION NUMBER	v3.0	PHONE NUMBER	908-283-4260
Date		(extension)	

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Enter appropriate data in cells which are highlighted in yellow only.
Enter the total applied for Regulatory Asset amounts for each account in the appropriate cells below.
Debits should be recorded as positive numbers and credits should be recorded as negative numbers.
Repeat cells going across as necessary for each year in application

Account Description	Account Number	2005										2006													
		Opening Principal Amounts as of Jan-1-05 ¹	Transactions (additions) during 2005, excluding interest and adjustments ⁶	Transactions (reductions) during 2005, excluding interest and adjustments ⁶	Adjustments during 2005 - instructed by Board ²	Adjustments during 2005 - other ³	Closing Principal Balance as of Dec-31-05	Opening Interest Amounts as of Jan-1-05	Interest Jan-1 to Dec31-05	Closing Interest Amounts as of Dec-31-05	Opening Principal Amounts as of Jan-1-06	Transactions (additions) during 2006, excluding interest and adjustments ⁶	Transactions (reductions) during 2006, excluding interest and adjustments ⁶	Adjustments during 2006 - instructed by Board ²	Adjustments during 2006 - other ³	Transfer of Board approved amounts to 1590 as per 2006 EDR	Closing Principal Balance as of Dec-31-06	Opening Interest Amounts as of Jan-1-06							
RSVA - Wholesale Market Service Charge	1580	\$ (267,757)	\$ 5,587,753			\$ 5,319,996	\$ (23,595)	\$ 106,957	\$ 83,363	\$ 5,319,996	\$ (10,216,417)		\$ -	\$ -	\$ 267,757	\$ (4,628,664)	\$ 83,363								
RSVA - One-time Wholesale Market Service	1582	\$ 460,984	\$ 437,418			\$ 898,402	\$ 21,275	\$ 43,265	\$ 64,540	\$ 898,402	\$ -		\$ -	\$ -	\$ (460,984)	\$ 437,418	\$ 64,540								
RSVA - Retail Transmission Network Charge	1584	\$ (1,713,447)	\$ 1,765,581			\$ 52,134	\$ (57,140)	\$ 35,084	\$ (22,056)	\$ 52,134	\$ 1,358,422		\$ -	\$ -	\$ -	\$ 1,410,556	\$ (22,056)								
RSVA - Retail Transmission Connection Charge	1586	\$ (2,517,648)	\$ (562,736)			\$ (3,080,384)	\$ (89,388)	\$ (129,494)	\$ (218,880)	\$ (3,080,384)	\$ 676,484				\$ -	\$ (2,403,900)	\$ (218,880)								
Sub-Totals		\$ (4,037,867)	\$ 7,228,016		\$ -	\$ -	\$ 3,190,149	\$ (148,845)	\$ 55,812	\$ (93,033)	\$ 3,190,149	\$ (8,181,511)		\$ -	\$ -	\$ (193,227)	\$ (5,184,590)	\$ (93,033)							
Other Regulatory Assets - Sub-Account - OEB Cost Assessments	1508	\$ 424,709	\$ 687,860			\$ 1,112,568	\$ 10,223	\$ 41,998	\$ 52,221	\$ 1,112,568	\$ 214,119	\$ (127,231)				\$ 1,199,457	\$ 52,221								
Other Regulatory Assets - Sub-Account - Pension Contributions	1508	\$ 874,227	\$ 1,041,002			\$ 1,915,229	\$ -	\$ 48,948	\$ 48,948	\$ 1,915,229	\$ 330,735	\$ (289,734)				\$ 1,956,230	\$ 48,948								
Other Regulatory Assets - Sub-Account - Other ⁷	1508					\$ -			\$ -	\$ -						\$ -	\$ -								
Other Regulatory Assets - Sub-Account - Other ⁷	1508					\$ -			\$ -	\$ -						\$ -	\$ -								
Other Regulatory Assets - Sub-Account - Other ⁷	1508					\$ -			\$ -	\$ -						\$ -	\$ -								
Retail Cost Variance Account - Retail	1518	\$ 8,224	\$ 65,403			\$ 73,627	\$ 262	\$ 2,260	\$ 2,521	\$ 73,627	\$ 41,202				\$ (8,223)	\$ 106,605	\$ 2,521								
Retail Cost Variance Account - STR	1548	\$ 51,395	\$ 87,436			\$ 138,831	\$ 1,005	\$ 6,390	\$ 7,396	\$ 138,831	\$ 85,578				\$ (51,395)	\$ 173,014	\$ 7,396								
Misc. Deferred Debits	1525	\$ -	\$ -			\$ -	\$ -	\$ -	\$ -	\$ -	\$ 21,095					\$ 21,095	\$ -								
LV Variance Account (Note 10)	1550	\$ -	\$ -			\$ -	\$ -	\$ -	\$ -	\$ -	\$ (218,851)					\$ (218,851)	\$ -								
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital	1555					\$ -			\$ -	\$ -						\$ -	\$ -								
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries	1555					\$ -			\$ -	\$ -						\$ -	\$ -								
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs	1555					\$ -			\$ -	\$ -						\$ -	\$ -								
Smart Meter O&A Variance	1556					\$ -			\$ -	\$ -						\$ -	\$ -								
Conservation and Demand Management Expenditures and Recoveries	1565					\$ -			\$ -	\$ -						\$ -	\$ -								
CDM Contra	1566					\$ -			\$ -	\$ -						\$ -	\$ -								
Qualifying Transition Costs ⁹	1570					\$ -			\$ -	\$ -	n/a	n/a				\$ -	\$ -								
Pre-Market Opening Energy Variances Total ⁹	1571		n/a	n/a		\$ -			\$ -	\$ -	n/a	n/a				\$ -	\$ -								
Extra-Ordinary Event Costs	1572					\$ -			\$ -	\$ -						\$ -	\$ -								
Deferred Rate Impact Amounts	1574					\$ -			\$ -	\$ -						\$ -	\$ -								
Other Deferred Credits	2425					\$ -			\$ -	\$ -						\$ -	\$ -								
Sub-Totals		\$ 1,358,554	\$ 1,881,701	\$ -	\$ -	\$ -	\$ 3,240,256	\$ 11,489	\$ 99,597	\$ 111,086	\$ 3,240,256	\$ 473,878	\$ (416,965)	\$ -	\$ -	\$ (59,619)	\$ 3,237,550	\$ 111,086							
Deferred Payments in Lieu of Taxes	1562					see PILs reconciliation requested										see PILs reconciliation requested									
2006 PILs & Taxes Variance	1592					see PILs reconciliation requested										see PILs reconciliation requested									
Sub-Totals						see PILs reconciliation requested										see PILs reconciliation requested									
Total		\$ (2,679,313)	\$ 9,109,718	\$ -	\$ -	\$ -	\$ 6,430,405	\$ (137,355)	\$ 155,409	\$ 18,054	\$ 6,430,405	\$ (7,707,634)	\$ (416,965)	\$ -	\$ -	\$ (252,846)	\$ (1,947,040)	\$ 18,054							
The following is not included in the total claim but is included on a memo basis:																									
Deferred PILs Contra Account ⁸	1563					see PILs reconciliation requested										see PILs reconciliation requested									
RSVA - Power (including Global Adjustment)	1588	\$ (2,850,219)	\$ (8,339,251)			\$ (11,189,470)	\$ (115,492)	\$ (593,445)	\$ (708,937)	\$ (11,189,470)	\$ 9,470,216				\$ 2,850,219	\$ 1,130,965	\$ (708,937)								
RSVA - Power - Sub-Account - Global Adjustment ⁸	1588	\$ -	\$ (6,402,236)			\$ (6,402,236)	\$ -	\$ (334,123)	\$ (334,123)	\$ (6,402,236)	\$ 13,115,415					\$ 6,713,179	\$ (334,123)								
Recovery of Regulatory Asset Balances	1590	\$ (5,254,873)	\$ -	\$ (7,705,630)	\$ 29,845,816	\$ 16,885,313	\$ (115,426)	\$ 892,285	\$ 776,859	\$ 16,885,313	\$ 388,262	\$ (7,372,745)	\$ (2,713,917)			\$ 7,186,913	\$ 776,859								

SHEET 1 - Regulatory Assets - Continuity Schedule

NAME OF UTILITY	Enersource Hydro Mississauga
NAME OF CONTACT	John Bonade
E-mail Address	jbomade@enersource.com
VERSION NUMBER	v3.0
Date	

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Account Description	Account Number	Interest Jan-1 to Dec31-06	Transfer of Board-approved amounts to 1590 as per 2006 EDR	Closing Interest Amounts as of Dec-31-06	Projected Interest on Dec 31 -06 balance from Jan 1, 2007 to Dec 31, 2007 ^a	Projected Interest on Dec 31 -06 balance from Jan 1, 2008 to April 30, 2008 ^b	Claim before Forecasted Transactions	Forecasted Transactions, Excluding Interest from Jan 1, 2007 to Dec 31, 2007	Forecasted Transactions, Excluding Interest from Jan 1, 2008 to April 30, 2008	Projected Interest from Jan 1, 2007 to April 30, 2008 on Forecasted Transx (Excl Interest) from Jan 1, 2007 to December 31, 2007	Projected Interest from Jan 1, 2008 to April 30, 2008 on Forecasted Transx (Excl Interest) from Jan 1, 2008 to April 30, 2008	Total Claim
RSVA - Wholesale Market Service Charge	1580	\$ 76,815	\$ 23,595	\$ 183,773			\$ (4,444,891)					\$ (4,444,891)
RSVA - One-time Wholesale Market Service	1582	\$ 45,636	\$ (21,275)	\$ 88,902			\$ 526,320					\$ 526,320
RSVA - Retail Transmission Network Charge	1584	\$ (6,962)	\$ -	\$ (29,018)			\$ 1,381,538					\$ 1,381,538
RSVA - Retail Transmission Connection Charge	1586	\$ (179,336)	\$ -	\$ (398,216)			\$ (2,802,116)					\$ (2,802,116)
Sub-Totals		\$ (63,847)	\$ 2,320	\$ (154,559)	\$ -	\$ -	\$ (5,339,149)	\$ -	\$ -	\$ -	\$ -	\$ (5,339,149)
Other Regulatory Assets - Sub-Account - OEB Cost Assessments	1508	\$ 60,594		\$ 112,815	\$ 55,055	\$ 18,352	\$ 1,385,678	\$ (187,872)	\$ (68,896)	\$ (3,965)	\$ (3,248)	\$ 1,121,697
Other Regulatory Assets - Sub-Account - Pension Contributions	1508	\$ 89,101		\$ 138,049	\$ 89,791	\$ 29,930	\$ 2,214,000	\$ (431,708)	\$ (152,660)	\$ (9,086)	\$ (7,456)	\$ 1,613,090
Other Regulatory Assets - Sub-Account - Other ^c	1508			\$ -			\$ -					\$ -
Other Regulatory Assets - Sub-Account - Other ^d	1508			\$ -			\$ -					\$ -
Retail Cost Variance Account - Retail	1518	\$ 5,134	\$ (262)	\$ 7,393			\$ 113,999					\$ 113,999
Retail Cost Variance Account - STR	1548	\$ 9,314	\$ (1,005)	\$ 15,704			\$ 188,718					\$ 188,718
Misc. Deferred Debits	1525		\$ 762	\$ 762	\$ 968	\$ 323	\$ 23,147	\$ -	\$ -	\$ -	\$ -	\$ 23,147
LV Variance Account (Note 10)	1550	\$ (2,847)		\$ (2,847)		\$ -	\$ (221,698)					\$ (221,698)
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital	1555			\$ -			\$ -					\$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries	1555			\$ -			\$ -					\$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs	1555			\$ -			\$ -					\$ -
Smart Meter O&M Variance	1556			\$ -			\$ -					\$ -
Conservation and Demand Management Expenditures and Recoveries	1565			\$ -			\$ -					\$ -
CDM Contra	1566			\$ -			\$ -					\$ -
Qualifying Transition Costs ^e	1570			\$ -			\$ -					\$ -
Pre-Market Opening Energy Variances Total ^b	1571			\$ -			\$ -					\$ -
Extra-Ordinary Event Costs	1572			\$ -			\$ -					\$ -
Deferred Rate Impact Amounts	1574			\$ -			\$ -					\$ -
Other Deferred Credits	2425			\$ -			\$ -					\$ -
Sub-Totals		\$ 161,295	\$ (505)	\$ 271,876	\$ 145,814	\$ 48,605	\$ 3,703,845	\$ (619,580)	\$ (221,556)	\$ (13,051)	\$ (10,704)	\$ 2,838,954
Deferred Payments in Lieu of Taxes	1562						\$ (2,115,347)					\$ (2,115,347)
2006 PILs & Taxes Variance	1592						\$ 71,909					\$ (30,477)
Sub-Totals							\$ (2,043,438)					\$ (2,145,824)
Total		\$ 97,449	\$ 1,815	\$ 117,317	\$ 145,814	\$ 48,605	\$ (3,678,742)	\$ (619,580)	\$ (221,556)	\$ (13,051)	\$ (10,704)	\$ (4,646,019)
The following is not included in the total claim but is included on a memo basis:												
Deferred PILs Contra Account ^a	1563						\$ 2,115,347					\$ 2,115,347
RSVA - Power (including Global Adjustment)	1588	\$ (259,792)	\$ 115,492	\$ (853,238)			\$ 277,728					\$ 277,728
RSVA - Power - Sub-Account - Global Adjustment ^a	1588	\$ 148,350		\$ (185,773)			\$ 6,527,406					\$ 6,527,406
Recovery of Regulatory Asset Balances	1590	\$ 680,746		\$ 1,457,605	\$ 302,515	\$ 100,838	\$ 9,047,872	\$ (5,392,170)	\$ (1,927,904)	\$ (102,570)	\$ (87,807)	\$ 1,537,421

S:\2008 Rate Application_sent Aug.22\Interrogatories\Board Staff Interrogatories\Answers to OEB\FINAL Attachments\#44

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RCVA and RSVA's Accounts

Retail Cost Variances (RCVAs)

1518 RCVA Retail	
1548 RCVA STR	
Total Retail Cost Variances Accounts	

Retail Settlement Variances (RSVAs)

1580 RSVA WHMS	
1582 RSVA WHMS - One Time	
1584 RSVA Network	
1586 RSVA Connection	
1588 RSVA Power (Excluding Global Adjustment)	
Total Retail Settlement Variances Accounts	
Total RCVAs and RSVAs	

31-Dec-05		
Principal	Interest	Total
73,627	2,521	76,148
138,831	7,396	146,227
212,458	9,917	222,375
5,319,996	83,363	5,403,359
898,402	64,540	962,942
52,134	(22,056)	30,078
(3,080,384)	(218,880)	(3,299,264)
(4,164,151)	(265,793)	(4,429,944)
(974,003)	(358,826)	(1,332,829)
(761,545)	(348,909)	(1,110,454)

31-Dec-06		
Principal	Interest	Total
106,705	7,396	114,101
173,014	15,704	188,718
279,719	23,100	302,819
(4,628,663)	183,772	(4,444,891)
437,418	88,902	526,320
1,410,556	(29,018)	1,381,538
(2,403,900)	(398,216)	(2,802,116)
(5,582,213)	(667,465)	(6,249,678)
(10,766,802)	(822,025)	(11,588,827)
(10,487,083)	(798,925)	(11,286,008)

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Enersource Hydro Mississauga
2008 Bill Impacts
Board Staff Interrogatory # 45 (b)

Account 1525 - Ontario Price Credit				
	Bill with Rate Rider	Bill without Rate Rider	Variance \$	Variance %
Residential				
Consumption 800 kWh 0 kW	\$ 94.55	\$ 94.54	\$ 0.00	0.00%
Consumption 1,000 kWh 0 kW	\$ 116.15	\$ 116.15	\$ 0.01	0.00%
GS < 50 kW				
Consumption 3,500 kWh 0 kW	\$ 417.57	\$ 417.59	\$ (0.02)	0.00%
Small Commercial and USL				
Consumption 300 kWh 0 kW	\$ 51.77	\$ 51.76	\$ 0.00	0.01%
GS 50 - 499 kW				
Consumption 48,700 kWh 140 kW	\$ 5,443.16	\$ 5,443.01	\$ 0.15	0.00%
GS 500 - 4999 kW				
Consumption 420,000 kWh 940 kW	\$ 42,010.26	\$ 42,009.62	\$ 0.63	0.00%
Large User > 5000 kW				
Consumption 9,200,000 kWh 15900 kW	\$ 882,805.40	\$ 882,792.51	\$ 12.89	0.00%
Streetlights				
Consumption 70 kWh 2 kW	\$ 18.49	\$ 18.49	\$ -	0.00%

Account 1592 - 2006 PILs Tax Variance			
Bill with Rate Rider	Bill without Rate Rider	Variance \$	Variance %
\$ 94.54	\$ 94.54	\$ (0.01)	-0.01%
\$ 116.14	\$ 116.15	\$ (0.01)	-0.01%
\$ 417.57	\$ 417.59	\$ (0.02)	0.00%
\$ 51.76	\$ 51.76	\$ (0.01)	-0.01%
\$ 5,442.81	\$ 5,443.01	\$ (0.20)	0.00%
\$ 42,008.79	\$ 42,009.62	\$ (0.83)	0.00%
\$ 882,775.54	\$ 882,792.51	\$ (16.97)	0.00%
\$ 18.49	\$ 18.49	\$ -	0.00%

Enersource Hydro Mississauga
2008 Bill Impacts
Board Staff Interrogatory # 45 (b)

Residential	
Consumption	800 kWh 0 kW
Consumption	1,000 kWh 0 kW
GS < 50 kW	
Consumption	3,500 kWh 0 kW
Small Commercial and USL	
Consumption	300 kWh 0 kW
GS 50 - 499 kW	
Consumption	48,700 kWh 140 kW
GS 500 - 4999 kW	
Consumption	420,000 kWh 940 kW
Large User > 5000 kW	
Consumption	9,200,000 kWh 15900 kW
Streetlights	
Consumption	70 kWh 2 kW

Account 1508 - OEB Assessed Costs			
Bill with Rate Rider	Bill without Rate Rider	Variance \$	Variance %
\$ 94.76	\$ 94.54	\$ 0.22	0.23%
\$ 116.42	\$ 116.15	\$ 0.28	0.24%
\$ 416.70	\$ 417.59	\$ (0.89)	-0.21%
\$ 52.00	\$ 51.76	\$ 0.23	0.45%
\$ 5,450.50	\$ 5,443.01	\$ 7.49	0.14%
\$ 42,040.26	\$ 42,009.62	\$ 30.63	0.07%
\$ 883,417.18	\$ 882,792.51	\$ 624.66	0.07%
\$ 18.59	\$ 18.49	\$ -	0.00%

Account 1508 - OMERS Pension Costs			
Bill with Rate Rider	Bill without Rate Rider	Variance \$	Variance %
\$ 94.86	\$ 94.54	\$ 0.32	0.33%
\$ 116.54	\$ 116.15	\$ 0.40	0.34%
\$ 416.31	\$ 417.59	\$ (1.28)	-0.31%
\$ 52.10	\$ 51.76	\$ 0.34	0.65%
\$ 5,453.78	\$ 5,443.01	\$ 10.77	0.20%
\$ 42,053.68	\$ 42,009.62	\$ 44.06	0.10%
\$ 883,690.83	\$ 882,792.51	\$ 898.32	0.10%
\$ 18.63	\$ 18.49	\$ -	0.00%

Enersource Hydro Mississauga
2008 Bill Impacts
Board Staff Interrogatory # 45 (b)

Residential	
Consumption	800 kWh 0 kW
Consumption	1,000 kWh 0 kW
GS < 50 kW	
Consumption	3,500 kWh 0 kW
Small Commercial and USL	
Consumption	300 kWh 0 kW
GS 50 - 499 kW	
Consumption	48,700 kWh 140 kW
GS 500 - 4999 kW	
Consumption	420,000 kWh 940 kW
Large User > 5000 kW	
Consumption	9,200,000 kWh 15900 kW
Streetlights	
Consumption	70 kWh 2 kW

Account 1590 - Interest on Regulatory Assets			
Bill with Rate Rider	Bill without Rate Rider	Variance \$	Variance %
\$ 94.85	\$ 94.54	\$ 0.30	0.32%
\$ 116.53	\$ 116.15	\$ 0.38	0.32%
\$ 418.81	\$ 417.59	\$ 1.22	0.29%
\$ 52.09	\$ 51.76	\$ 0.32	0.62%
\$ 5,453.27	\$ 5,443.01	\$ 10.26	0.19%
\$ 42,051.61	\$ 42,009.62	\$ 41.99	0.10%
\$ 883,648.69	\$ 882,792.51	\$ 856.18	0.10%
\$ 18.62	\$ 18.49	\$ -	0.00%

Account 1518 - RCVA Retail			
Bill with Rate Rider	Bill without Rate Rider	Variance \$	Variance %
\$ 94.57	\$ 94.54	\$ 0.02	0.02%
\$ 116.18	\$ 116.15	\$ 0.03	0.02%
\$ 417.68	\$ 417.59	\$ 0.09	0.02%
\$ 51.79	\$ 51.76	\$ 0.02	0.05%
\$ 5,443.77	\$ 5,443.01	\$ 0.76	0.01%
\$ 42,012.74	\$ 42,009.62	\$ 3.12	0.01%
\$ 882,856.06	\$ 882,792.51	\$ 63.54	0.01%
\$ 18.50	\$ 18.49	\$ -	0.00%

Enersource Hydro Mississauga
2008 Bill Impacts
Board Staff Interrogatory # 45 (b)

Residential	
Consumption	800 kWh 0 kW
Consumption	1,000 kWh 0 kW
GS < 50 kW	
Consumption	3,500 kWh 0 kW
Small Commercial and USL	
Consumption	300 kWh 0 kW
GS 50 - 499 kW	
Consumption	48,700 kWh 140 kW
GS 500 - 4999 kW	
Consumption	420,000 kWh 940 kW
Large User > 5000 kW	
Consumption	9,200,000 kWh 15900 kW
Streetlights	
Consumption	70 kWh 2 kW

Account 1548 - RCVA STR			
Bill with Rate Rider	Bill without Rate Rider	Variance \$	Variance %
\$ 94.58	\$ 94.54	\$ 0.04	0.04%
\$ 116.19	\$ 116.15	\$ 0.05	0.04%
\$ 417.74	\$ 417.59	\$ 0.15	0.04%
\$ 51.80	\$ 51.76	\$ 0.04	0.08%
\$ 5,444.27	\$ 5,443.01	\$ 1.26	0.02%
\$ 42,014.78	\$ 42,009.62	\$ 5.15	0.01%
\$ 882,897.61	\$ 882,792.51	\$ 105.10	0.01%
\$ 18.51	\$ 18.49	\$ -	0.00%

Account 1580 - RSVA WHMS			
Bill with Rate Rider	Bill without Rate Rider	Variance \$	Variance %
\$ 93.67	\$ 94.54	\$ (0.87)	-0.92%
\$ 115.06	\$ 116.15	\$ (1.09)	-0.94%
\$ 414.07	\$ 417.59	\$ (3.52)	-0.84%
\$ 50.83	\$ 51.76	\$ (0.93)	-1.80%
\$ 5,413.34	\$ 5,443.01	\$ (29.67)	-0.55%
\$ 41,888.23	\$ 42,009.62	\$ (121.40)	-0.29%
\$ 880,317.19	\$ 882,792.51	\$ (2,475.32)	-0.28%
\$ 18.10	\$ 18.49	\$ -	0.00%

Enersource Hydro Mississauga
2008 Bill Impacts
Board Staff Interrogatory # 45 (b)

Residential	
Consumption	800 kWh 0 kW
Consumption	1,000 kWh 0 kW
GS < 50 kW	
Consumption	3,500 kWh 0 kW
Small Commercial and USL	
Consumption	300 kWh 0 kW
GS 50 - 499 kW	
Consumption	48,700 kWh 140 kW
GS 500 - 4999 kW	
Consumption	420,000 kWh 940 kW
Large User > 5000 kW	
Consumption	9,200,000 kWh 15900 kW
Streetlights	
Consumption	70 kWh 2 kW

Account 1582 - RSVA WHMS One Time			
Bill with Rate Rider	Bill without Rate Rider	Variance \$	Variance %
\$ 94.65	\$ 94.54	\$ 0.10	0.11%
\$ 116.28	\$ 116.15	\$ 0.13	0.11%
\$ 418.01	\$ 417.59	\$ 0.42	0.10%
\$ 51.88	\$ 51.76	\$ 0.11	0.21%
\$ 5,446.52	\$ 5,443.01	\$ 3.51	0.06%
\$ 42,024.00	\$ 42,009.62	\$ 14.37	0.03%
\$ 883,085.62	\$ 882,792.51	\$ 293.10	0.03%
\$ 18.53	\$ 18.49	\$ -	0.00%

Account 1584 - RSVA Network			
Bill with Rate Rider	Bill without Rate Rider	Variance \$	Variance %
\$ 94.82	\$ 94.54	\$ 0.27	0.29%
\$ 116.49	\$ 116.15	\$ 0.34	0.29%
\$ 418.69	\$ 417.59	\$ 1.10	0.26%
\$ 52.05	\$ 51.76	\$ 0.29	0.56%
\$ 5,452.23	\$ 5,443.01	\$ 9.22	0.17%
\$ 42,047.35	\$ 42,009.62	\$ 37.73	0.09%
\$ 883,561.88	\$ 882,792.51	\$ 769.37	0.09%
\$ 18.61	\$ 18.49	\$ -	0.00%

Enersource Hydro Mississauga
2008 Bill Impacts
Board Staff Interrogatory # 45 (b)

Residential	
Consumption	800 kWh 0 kW
Consumption	1,000 kWh 0 kW
GS < 50 kW	
Consumption	3,500 kWh 0 kW
Small Commercial and USL	
Consumption	300 kWh 0 kW
GS 50 - 499 kW	
Consumption	48,700 kWh 140 kW
GS 500 - 4999 kW	
Consumption	420,000 kWh 940 kW
Large User > 5000 kW	
Consumption	9,200,000 kWh 15900 kW
Streetlights	
Consumption	70 kWh 2 kW

Account 1586 - RSVA Connection			
Bill with Rate Rider	Bill without Rate Rider	Variance \$	Variance %
\$ 93.99	\$ 94.54	\$ (0.55)	-0.58%
\$ 115.46	\$ 116.15	\$ (0.69)	-0.59%
\$ 415.37	\$ 417.59	\$ (2.22)	-0.53%
\$ 51.18	\$ 51.76	\$ (0.59)	-1.13%
\$ 5,424.31	\$ 5,443.01	\$ (18.70)	-0.34%
\$ 41,933.09	\$ 42,009.62	\$ (76.53)	-0.18%
\$ 881,232.04	\$ 882,792.51	\$ (1,560.47)	-0.18%
\$ 18.24	\$ 18.49	\$ -	0.00%

Account 1588 - RSVA Power			
Bill with Rate Rider	Bill without Rate Rider	Variance \$	Variance %
\$ 93.32	\$ 94.54	\$ (1.23)	-1.30%
\$ 114.61	\$ 116.15	\$ (1.53)	-1.32%
\$ 412.63	\$ 417.59	\$ (4.96)	-1.19%
\$ 50.46	\$ 51.76	\$ (1.31)	-2.53%
\$ 5,401.30	\$ 5,443.01	\$ (41.71)	-0.77%
\$ 41,838.94	\$ 42,009.62	\$ (170.69)	-0.41%
\$ 879,312.12	\$ 882,792.51	\$ (3,480.39)	-0.39%
\$ 17.94	\$ 18.49	\$ -	0.00%

Enersource Hydro Mississauga
2008 Bill Impacts
Board Staff Interrogatory # 45 (b)

45b

Residential	
Consumption	800 kWh 0 kW
Consumption	1,000 kWh 0 kW
GS < 50 kW	
Consumption	3,500 kWh 0 kW
Small Commercial and USL	
Consumption	300 kWh 0 kW
GS 50 - 499 kW	
Consumption	48,700 kWh 140 kW
GS 500 - 4999 kW	
Consumption	420,000 kWh 940 kW
Large User > 5000 kW	
Consumption	9,200,000 kWh 15900 kW
Streetlights	
Consumption	70 kWh 2 kW

2008 Test Year LV Charges				
Bill with Rate Rider	Bill without Rate Rider	Variance \$	Variance %	
\$ 94.58	\$ 94.54	\$ 0.03	0.03%	
\$ 116.19	\$ 116.15	\$ 0.04	0.03%	
\$ 417.71	\$ 417.59	\$ 0.12	0.03%	
\$ 51.78	\$ 51.76	\$ 0.01	0.02%	
\$ 5,444.93	\$ 5,443.01	\$ 1.92	0.04%	
\$ 42,022.25	\$ 42,009.62	\$ 12.63	0.03%	
\$ 883,020.64	\$ 882,792.51	\$ 228.13	0.03%	
\$ 18.51	\$ 18.49	\$ -	0.00%	

45b

LRAM			
Bill with Rate Rider	Bill without Rate Rider	Variance \$	Variance %
\$ 94.74	\$ 94.54	\$ 0.20	0.21%
\$ 116.40	\$ 116.15	\$ 0.25	0.21%
\$ 417.63	\$ 417.59	\$ 0.04	0.01%
\$ 51.76	\$ 51.76	\$ -	0.00%
\$ 5,443.03	\$ 5,443.01	\$ 0.02	0.00%
\$ 42,009.68	\$ 42,009.62	\$ 0.06	0.00%
\$ 882,792.51	\$ 882,792.51	\$ -	0.00%
\$ 18.49	\$ 18.49	\$ -	0.00%

45b

SSM			
Bill with Rate Rider	Bill without Rate Rider	Variance \$	Variance %
\$ 94.94	\$ 94.54	\$ 0.40	0.42%
\$ 116.64	\$ 116.15	\$ 0.50	0.43%
\$ 417.60	\$ 417.59	\$ 0.01	0.00%
\$ 51.76	\$ 51.76	\$ -	0.00%
\$ 5,443.56	\$ 5,443.01	\$ 0.55	0.01%
\$ 42,073.86	\$ 42,009.62	\$ 64.23	0.15%
\$ 884,620.59	\$ 882,792.51	\$ 1,828.07	0.21%
\$ 18.49	\$ 18.49	\$ -	0.00%



RATE RIDERS - ACCOUNT 1525 (Ontario Price Credit)

	Allocation to Customer Classes %	Ontario Price Credit Admin Costs	Total to be recovered over 1 year				
	Total for customer class as % of Total for all classes	\$ 23,147	\$ 23,147	kWh Forecast 2008	kW Forecast 2008	Proposed Rate Riders	Revenue from Rate Riders
RESIDENTIAL	35.82%	\$ 8,291	\$ 8,291	1,547,398,184		\$ 0.0000	\$ 8,291
General Service < 50 kW	13.82%	\$ 3,200	\$ 3,200	646,726,132		\$ 0.0000	\$ 3,200
Small Commercial	0.78%	\$ 181	\$ 181	11,905,587		\$ 0.0000	\$ 181
General Service 50 kW - 499 kW	28.85%	\$ 6,679	\$ 6,679		6,415,732	\$ 0.0010	\$ 6,679
General Service 500 kW - 4999 kW	14.55%	\$ 3,369	\$ 3,369		5,310,121	\$ 0.0006	\$ 3,369
Large Use (> 5000 kW)	5.69%	\$ 1,316	\$ 1,316		1,720,956	\$ 0.0008	\$ 1,316
Street Lighting	0.48%	\$ 111	\$ 111		115,190	\$ 0.0010	\$ 111
TOTALS	100.00%	\$ 23,147	\$ 23,147				\$ 23,147



RATE RIDERS - ACCOUNT 1592 (LCT Over Recovery)

	Allocation to Customer Classes %	LCT Over Recovery	Total to be recovered over 1 year				
	Total for customer class as % of Total for all classes	\$ (30,477)	\$ (30,477)	kWh Forecast 2008	kW Forecast 2008	Proposed Rate Riders	Revenue from Rate Riders
RESIDENTIAL	35.82%	\$ (10,917)	\$ (10,917)	1,547,398,184		\$ (0.0000)	\$ (10,917)
General Service < 50 kW	13.82%	\$ (4,213)	\$ (4,213)	646,726,132		\$ (0.0000)	\$ (4,213)
Small Commercial	0.78%	\$ (239)	\$ (239)	11,905,587		\$ (0.0000)	\$ (239)
General Service 50 kW - 499 kW	28.85%	\$ (8,794)	\$ (8,794)		6,415,732	\$ (0.0014)	\$ (8,794)
General Service 500 kW - 4999 kW	14.55%	\$ (4,436)	\$ (4,436)		5,310,121	\$ (0.0008)	\$ (4,436)
Large Use (> 5000 kW)	5.69%	\$ (1,733)	\$ (1,733)		1,720,956	\$ (0.0010)	\$ (1,733)
Street Lighting	0.48%	\$ (146)	\$ (146)		115,190	\$ (0.0013)	\$ (146)
TOTALS	100.00%	\$ (30,477)	\$ (30,477)				\$ (30,477)



RATE RIDERS - ACCOUNT 1508 (OEB Assessed Costs)

	Allocation to Customer Classes %	Deferred OEB Costs - 2005/6	Total to be recovered over 1 year				
	Total for customer class as % of Total for all classes	\$ 1,121,697	\$ 1,121,697	kWh Forecast 2008	kW Forecast 2008	Proposed Rate Riders	Revenue from Rate Riders
RESIDENTIAL	35.82%	\$ 401,789	\$ 401,789	1,547,398,184		\$ 0.0003	\$ 401,789
General Service < 50 kW	13.82%	\$ 155,051	\$ 155,051	646,726,132		\$ 0.0002	\$ 155,051
Small Commercial	0.78%	\$ 8,792	\$ 8,792	11,905,587		\$ 0.0007	\$ 8,792
General Service 50 kW - 499 kW	28.85%	\$ 323,652	\$ 323,652		6,415,732	\$ 0.0504	\$ 323,652
General Service 500 kW - 4999 kW	14.55%	\$ 163,263	\$ 163,263		5,310,121	\$ 0.0307	\$ 163,263
Large Use (> 5000 kW)	5.69%	\$ 63,784	\$ 63,784		1,720,956	\$ 0.0371	\$ 63,784
Street Lighting	0.48%	\$ 5,366	\$ 5,366		115,190	\$ 0.0466	\$ 5,366
TOTALS	100.00%	\$ 1,121,697	\$ 1,121,697				\$ 1,121,697



RATE RIDERS - ACCOUNT 1508 (OEB Deferred Pension Costs)

	Allocation to Customer Classes %	OMERS Pension Deferral 2005/6	Total to be recovered over 1 year				
	Total for customer class as % of Total for all classes	\$ 1,613,090	\$ 1,613,090	kWh Forecast 2008	kW Forecast 2008	Proposed Rate Riders	Revenue from Rate Riders
RESIDENTIAL	35.82%	\$ 577,805	\$ 577,805	1,547,398,184		\$ 0.0004	\$ 577,805
General Service < 50 kW	13.82%	\$ 222,976	\$ 222,976	646,726,132		\$ 0.0003	\$ 222,976
Small Commercial	0.78%	\$ 12,644	\$ 12,644	11,905,587		\$ 0.0011	\$ 12,644
General Service 50 kW - 499 kW	28.85%	\$ 465,437	\$ 465,437		6,415,732	\$ 0.0725	\$ 465,437
General Service 500 kW - 4999 kW	14.55%	\$ 234,785	\$ 234,785		5,310,121	\$ 0.0442	\$ 234,785
Large Use (> 5000 kW)	5.69%	\$ 91,727	\$ 91,727		1,720,956	\$ 0.0533	\$ 91,727
Street Lighting	0.48%	\$ 7,716	\$ 7,716		115,190	\$ 0.0670	\$ 7,716
TOTALS	100.00%	\$ 1,613,090	\$ 1,613,090				\$ 1,613,090



RATE RIDERS - ACCOUNT 1590 (Interest on Regulatory Assets)

	Allocation to Customer Classes %	Interest on Regulatory Assets	Total to be recovered over 1 year				
	Total for customer class as % of Total for all classes	\$ 1,537,421	\$ 1,537,421	kWh Forecast 2008	kW Forecast 2008	Proposed Rate Riders	Revenue from Rate Riders
RESIDENTIAL	35.82%	\$ 550,700	\$ 550,700	1,547,398,184		\$ 0.0004	\$ 550,700
General Service < 50 kW	13.82%	\$ 212,517	\$ 212,517	646,726,132		\$ 0.0003	\$ 212,517
Small Commercial	0.78%	\$ 12,051	\$ 12,051	11,905,587		\$ 0.0010	\$ 12,051
General Service 50 kW - 499 kW	28.85%	\$ 443,604	\$ 443,604		6,415,732	\$ 0.0691	\$ 443,604
General Service 500 kW - 4999 kW	14.55%	\$ 223,771	\$ 223,771		5,310,121	\$ 0.0421	\$ 223,771
Large Use (> 5000 kW)	5.69%	\$ 87,424	\$ 87,424		1,720,956	\$ 0.0508	\$ 87,424
Street Lighting	0.48%	\$ 7,354	\$ 7,354		115,190	\$ 0.0638	\$ 7,354
TOTALS	100.00%	\$ 1,537,421	\$ 1,537,421				\$ 1,537,421



RATE RIDERS - ACCOUNT 1518 (RCVA Retail)

	Allocation to Customer Classes %	2006 RCVA Retail	Total to be recovered over 1 year				
	Total for customer class as % of Total for all classes			kWh Forecast 2008	kW Forecast 2008	Proposed Rate Riders	Revenue from Rate Riders
		114,101	\$ 114,101				
RESIDENTIAL	35.82%	40,871	\$ 40,871	1,547,398,184		\$ 0.0000	\$ 40,871
General Service < 50 kW	13.82%	15,772	\$ 15,772	646,726,132		\$ 0.0000	\$ 15,772
Small Commercial	0.78%	894	\$ 894	11,905,587		\$ 0.0001	\$ 894
General Service 50 kW - 499 kW	28.85%	32,922	\$ 32,922		6,415,732	\$ 0.0051	\$ 32,922
General Service 500 kW - 4999 kW	14.55%	16,607	\$ 16,607		5,310,121	\$ 0.0031	\$ 16,607
Large Use (> 5000 kW)	5.69%	6,488	\$ 6,488		1,720,956	\$ 0.0038	\$ 6,488
Street Lighting	0.48%	546	\$ 546		115,190	\$ 0.0047	\$ 546
TOTALS	100.00%	114,101	\$ 114,101				\$ 114,101



RATE RIDERS - ACCOUNT 1518 (RCVA STR)

	Allocation to Customer Classes %	2006 RCVA STR	Total to be recovered over 1 year				
	Total for customer class as % of Total for all classes			kWh Forecast 2008	kW Forecast 2008	Proposed Rate Riders	Revenue from Rate Riders
		188,718	\$ 188,718				
RESIDENTIAL	35.82%	67,598	\$ 67,598	1,547,398,184		\$ 0.0000	\$ 67,598
General Service < 50 kW	13.82%	26,086	\$ 26,086	646,726,132		\$ 0.0000	\$ 26,086
Small Commercial	0.78%	1,479	\$ 1,479	11,905,587		\$ 0.0001	\$ 1,479
General Service 50 kW - 499 kW	28.85%	54,452	\$ 54,452		6,415,732	\$ 0.0085	\$ 54,452
General Service 500 kW - 4999 kW	14.55%	27,468	\$ 27,468		5,310,121	\$ 0.0052	\$ 27,468
Large Use (> 5000 kW)	5.69%	10,731	\$ 10,731		1,720,956	\$ 0.0062	\$ 10,731
Street Lighting	0.48%	903	\$ 903		115,190	\$ 0.0078	\$ 903
TOTALS	100.00%	188,718	\$ 188,718				\$ 188,718



RATE RIDERS - ACCOUNT 1580 (RSVA WHMS)

	Allocation to Customer Classes %	2006 RSVA WHMS	Total to be recovered over 1 year				
	Total for customer class as % of Total for all classes			kWh Forecast 2008	kW Forecast 2008	Proposed Rate Riders	Revenue from Rate Riders
		4,444,891	\$ (4,444,891)				
RESIDENTIAL	35.82%	1,592,148	\$ (1,592,148)	1,547,398,184		\$ (0.0010)	\$ (1,592,148)
General Service < 50 kW	13.82%	614,415	\$ (614,415)	646,726,132		\$ (0.0010)	\$ (614,415)
Small Commercial	0.78%	34,841	\$ (34,841)	11,905,587		\$ (0.0029)	\$ (34,841)
General Service 50 kW - 499 kW	28.85%	1,282,518	\$ (1,282,518)		6,415,732	\$ (0.1999)	\$ (1,282,518)
General Service 500 kW - 4999 kW	14.55%	646,952	\$ (646,952)		5,310,121	\$ (0.1218)	\$ (646,952)
Large Use (> 5000 kW)	5.69%	252,754	\$ (252,754)		1,720,956	\$ (0.1469)	\$ (252,754)
Street Lighting	0.48%	21,262	\$ (21,262)		115,190	\$ (0.1846)	\$ (21,262)
TOTALS	100.00%	4,444,891	\$ (4,444,891)				\$ (4,444,891)



RATE RIDERS - ACCOUNT 1582 (RSVA WHMS One Time)

	Allocation to Customer Classes %	2006 RSVA WHMS One Time	Total to be recovered over 1 year				
	Total for customer class as % of Total for all classes	526,320	\$ 526,320	kWh Forecast 2008	kW Forecast 2008	Proposed Rate Riders	Revenue from Rate Riders
RESIDENTIAL	35.82%	188,526	\$ 188,526	1,547,398,184		\$ 0.0001	\$ 188,526
General Service < 50 kW	13.82%	72,753	\$ 72,753	646,726,132		\$ 0.0001	\$ 72,753
Small Commercial	0.78%	4,126	\$ 4,126	11,905,587		\$ 0.0003	\$ 4,126
General Service 50 kW - 499 kW	28.85%	151,863	\$ 151,863		6,415,732	\$ 0.0237	\$ 151,863
General Service 500 kW - 4999 kW	14.55%	76,606	\$ 76,606		5,310,121	\$ 0.0144	\$ 76,606
Large Use (> 5000 kW)	5.69%	29,929	\$ 29,929		1,720,956	\$ 0.0174	\$ 29,929
Street Lighting	0.48%	2,518	\$ 2,518		115,190	\$ 0.0219	\$ 2,518
TOTALS	100.00%	526,320	\$ 526,320				\$ 526,320



RATE RIDERS - ACCOUNT 1584 (RSVA Network)

	Allocation to Customer Classes %	2006 RSVA Network	Total to be recovered over 1 year				
	Total for customer class as % of Total for all classes			kWh Forecast 2008	kW Forecast 2008	Proposed Rate Riders	Revenue from Rate Riders
		1,381,538	\$ 1,381,538				
RESIDENTIAL	35.82%	494,863	\$ 494,863	1,547,398,184		\$ 0.0003	\$ 494,863
General Service < 50 kW	13.82%	190,969	\$ 190,969	646,726,132		\$ 0.0003	\$ 190,969
Small Commercial	0.78%	10,829	\$ 10,829	11,905,587		\$ 0.0009	\$ 10,829
General Service 50 kW - 499 kW	28.85%	398,626	\$ 398,626		6,415,732	\$ 0.0621	\$ 398,626
General Service 500 kW - 4999 kW	14.55%	201,082	\$ 201,082		5,310,121	\$ 0.0379	\$ 201,082
Large Use (> 5000 kW)	5.69%	78,560	\$ 78,560		1,720,956	\$ 0.0456	\$ 78,560
Street Lighting	0.48%	6,609	\$ 6,609		115,190	\$ 0.0574	\$ 6,609
TOTALS	100.00%	1,381,538	\$ 1,381,538				\$ 1,381,538



RATE RIDERS - ACCOUNT 1584 (RSVA Connection)

	Allocation to Customer Classes %	2006 RSVA Connection	Total to be recovered over 1 year				
	Total for customer class as % of Total for all classes			kWh Forecast 2008	kW Forecast 2008	Proposed Rate Riders	Revenue from Rate Riders
		2,802,116	\$ (2,802,116)				
RESIDENTIAL	35.82%	1,003,711	\$ (1,003,711)	1,547,398,184		\$ (0.0006)	\$ (1,003,711)
General Service < 50 kW	13.82%	387,335	\$ (387,335)	646,726,132		\$ (0.0006)	\$ (387,335)
Small Commercial	0.78%	21,964	\$ (21,964)	11,905,587		\$ (0.0018)	\$ (21,964)
General Service 50 kW - 499 kW	28.85%	808,516	\$ (808,516)		6,415,732	\$ (0.1260)	\$ (808,516)
General Service 500 kW - 4999 kW	14.55%	407,847	\$ (407,847)		5,310,121	\$ (0.0768)	\$ (407,847)
Large Use (> 5000 kW)	5.69%	159,339	\$ (159,339)		1,720,956	\$ (0.0926)	\$ (159,339)
Street Lighting	0.48%	13,404	\$ (13,404)		115,190	\$ (0.1164)	\$ (13,404)
TOTALS	100.00%	2,802,116	\$ (2,802,116)				\$ (2,802,116)



RATE RIDERS - ACCOUNT 1588 (RSVA Power)

	Allocation to Customer Classes %	2006 RSVA Connection	Total to be recovered over 1 year				
	Total for customer class as % of Total for all classes			kWh Forecast 2008	kW Forecast 2008	Proposed Rate Riders	Revenue from Rate Riders
		6,249,678	\$ (6,249,678)				
RESIDENTIAL	35.82%	2,238,618	\$ (2,238,618)	1,547,398,184		\$ (0.0014)	\$ (2,238,618)
General Service < 50 kW	13.82%	863,889	\$ (863,889)	646,726,132		\$ (0.0013)	\$ (863,889)
Small Commercial	0.78%	48,988	\$ (48,988)	11,905,587		\$ (0.0041)	\$ (48,988)
General Service 50 kW - 499 kW	28.85%	1,803,267	\$ (1,803,267)		6,415,732	\$ (0.2811)	\$ (1,803,267)
General Service 500 kW - 4999 kW	14.55%	909,638	\$ (909,638)		5,310,121	\$ (0.1713)	\$ (909,638)
Large Use (> 5000 kW)	5.69%	355,381	\$ (355,381)		1,720,956	\$ (0.2065)	\$ (355,381)
Street Lighting	0.48%	29,896	\$ (29,896)		115,190	\$ (0.2595)	\$ (29,896)
TOTALS	100.00%	6,249,678	\$ (6,249,678)				\$ (6,249,678)



RATE RIDERS - 2008 Test Year LV Charges

	Allocation to Customer Classes %	LV Charges for 2008 Test Year	Total to be recovered over 1 year				
		See "LV Charges Allocation" Sheet (Allocated per Model 2, Sheet B-4)		kWh Forecast 2008	kW Forecast 2008	Proposed Rate Riders	Revenue from Rate Riders
	Total for customer class as % of Total for all classes	\$ 252,886	\$ 252,886				
RESIDENTIAL	22.32%	\$ 56,446	\$ 56,446	1,547,398,184		\$ 0.0000	\$ 56,446
General Service < 50 kW	8.41%	\$ 21,278	\$ 21,278	646,726,132		\$ 0.0000	\$ 21,278
Small Commercial	0.15%	\$ 392	\$ 392	11,905,587		\$ 0.0000	\$ 392
General Service 50 kW - 499 kW	32.86%	\$ 83,100	\$ 83,100		6,415,732	\$ 0.0130	\$ 83,100
General Service 500 kW - 4999 kW	26.61%	\$ 67,298	\$ 67,298		5,310,121	\$ 0.0127	\$ 67,298
Large Use (> 5000 kW)	9.21%	\$ 23,294	\$ 23,294		1,720,956	\$ 0.0135	\$ 23,294
Street Lighting	0.43%	\$ 1,079	\$ 1,079		115,190	\$ 0.0094	\$ 1,079
TOTALS	100.00%	\$ 252,886	\$ 252,886				\$ 252,886



RATE RIDERS - LRAM to April 30, 2007

	Allocation to Customer Classes % for LRAM	LRAM to April 30, 2007	Total to be recovered over 1 year				
	Total kWh savings per class / Total kWh savings			kWh Forecast 2008	kW Forecast 2008	Proposed Rate Riders	Revenue from Rate Riders
		\$ 370,246	\$ 370,246				
RESIDENTIAL	97.96%	\$ 362,686	\$ 362,686	1,547,398,184		\$ 0.0002	\$ 362,686
General Service < 50 kW	1.76%	\$ 6,532	\$ 6,532	646,726,132		\$ 0.0000	\$ 6,532
Small Commercial	0.00%	\$ -	\$ -	11,905,587		\$ -	\$ -
General Service 50 kW - 499 kW	0.19%	\$ 704	\$ 704		6,415,732	\$ 0.0001	\$ 704
General Service 500 kW - 4999 kW	0.09%	\$ 324	\$ 324		5,310,121	\$ 0.0001	\$ 324
Large Use (> 5000 kW)	0.00%	\$ -	\$ -		1,720,956	\$ -	\$ -
Street Lighting	0.00%	\$ -	\$ -		115,190	\$ -	\$ -
TOTALS	100.00%	\$ 370,246	\$ 370,246				\$ 370,246



RATE RIDERS - SSM to April 30, 2007

	Allocation to Customer Classes % for SSM	SSM to April 30, 2007	Total to be recovered over 1 year				
	Total kWh savings per class / Total kWh savings			kWh Forecast 2008	kW Forecast 2008	Proposed Rate Riders	Revenue from Rate Riders
		\$ 1,279,685	\$ 1,279,685				
RESIDENTIAL	56.67%	\$ 725,214	\$ 725,214	1,547,398,184		\$ 0.0005	\$ 725,214
General Service < 50 kW	0.12%	\$ 1,511	\$ 1,511	646,726,132		\$ 0.0000	\$ 1,511
Small Commercial	0.00%	\$ -	\$ -	11,905,587		\$ -	\$ -
General Service 50 kW - 499 kW	1.87%	\$ 23,974	\$ 23,974		6,415,732	\$ 0.0037	\$ 23,974
General Service 500 kW - 4999 kW	26.75%	\$ 342,322	\$ 342,322		5,310,121	\$ 0.0645	\$ 342,322
Large Use (> 5000 kW)	14.59%	\$ 186,664	\$ 186,664		1,720,956	\$ 0.1085	\$ 186,664
Street Lighting	0.00%	\$ -	\$ -		115,190	\$ -	\$ -
TOTALS	100.00%	\$ 1,279,685	\$ 1,279,685				\$ 1,279,685

**Interest Rates Used to Calculate Regulatory Deferral and Variance Accounts
For the Period from January 1, 2005 to Present**

Variance and Deferral Accounts & CWIP	2005				2006				2007			
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
Variance and Deferral Accounts												
1508 Other Regulatory Assets	5.75	5.75	5.75	5.75	5.75	4.14	4.59	4.59	4.59	4.59	4.59	5.14
1508 Other Regulatory Assets - Sub-account OEB Cost Assessments	5.75	5.75	5.75	5.75	5.75	4.14	4.59	4.59	4.59	4.59	4.59	5.14
1508 Other Regulatory Assets - Sub-account Pension Contributions	3.88	3.88	3.88	3.88	3.88	4.14	4.59	4.59	4.59	4.59	4.59	5.14
1518 Retail Cost Variance Account - Retail	6.90	6.90	6.90	6.90	6.90	4.14	4.59	4.59	4.59	4.59	4.59	5.14
1525 Miscellaneous Deferred Debits	6.90	6.90	6.90	6.90	6.90	4.14	4.59	4.59	4.59	4.59	4.59	5.14
1525 Miscellaneous Deferred Debits, Sub-account Payments to Customers	6.90	6.90	6.90	6.90	6.90	4.14	4.59	4.59	4.59	4.59	4.59	5.14
1548 Retail Cost Variance Account - STR	6.90	6.90	6.90	6.90	6.90	4.14	4.59	4.59	4.59	4.59	4.59	5.14
1550 LV Variance Account	6.90	6.90	6.90	6.90	6.90	4.14	4.59	4.59	4.59	4.59	4.59	5.14
1555 Smart Meter Capital and Recovery Offset Variance Account	-	-	-	-	-	4.14	4.59	4.59	4.59	4.59	4.59	5.14
1556 Smart Meter OM&A Variance Account	-	-	-	-	-	4.14	4.59	4.59	4.59	4.59	4.59	5.14
1562 Deferred Payments in Lieu of Taxes	6.90	6.90	6.90	6.90	6.90	4.14	4.59	4.59	4.59	4.59	4.59	5.14
1563 PILs contra account	6.90	6.90	6.90	6.90	6.90	4.14	4.59	4.59	4.59	4.59	4.59	5.14
1580 Retail Settlement Variance Account - Wholesale Market Service Charges	6.90	6.90	6.90	6.90	6.90	4.14	4.59	4.59	4.59	4.59	4.59	5.14
1582 Retail Settlement Variance Account - One-time Wholesale Market Service	6.90	6.90	6.90	6.90	6.90	4.14	4.59	4.59	4.59	4.59	4.59	5.14
1584 Retail Settlement Variance Account - Retail Transmission Network Charges	6.90	6.90	6.90	6.90	6.90	4.14	4.59	4.59	4.59	4.59	4.59	5.14
1586 Retail Settlement Variance Account - Retail Transmission Connection Charges	6.90	6.90	6.90	6.90	6.90	4.14	4.59	4.59	4.59	4.59	4.59	5.14
1588 Retail Settlement Variance Account - Power	6.90	6.90	6.90	6.90	6.90	4.14	4.59	4.59	4.59	4.59	4.59	5.14
1588 RSVA Power - Sub-account Global Adjustments	6.90	6.90	6.90	6.90	6.90	4.14	4.59	4.59	4.59	4.59	4.59	5.14
1590 Recovery of Regulatory Asset Balances	6.90	6.90	6.90	6.90	6.90	4.14	4.59	4.59	4.59	4.59	4.59	5.14
1592 2006 PILs and Taxes Variances	6.90	6.90	6.90	6.90	6.90	4.14	4.59	4.59	4.59	4.59	4.59	5.14
Construction Work in Progress Account	6.90	6.90	6.90	6.90	6.90	4.14	4.59	4.59	4.59	4.59	4.59	5.14
2055 Construction Work in Progress	6.90	6.90	6.90	6.90	6.90	4.68	5.05	4.72	4.72	4.72	5.18	5.18

Check - Did we used 6.9 for all accounts prior to q1 06 for CWIP as well. Check SM

ENERSOURCE - CDM Programs

Ref: OEB Filing Requirements for Transmission and Distribution Applications - EB-2006-0170, November 14, 2006

Program Duration					
Funding Mechanism & CDM Program	Start	End	Years	Months	Notes
All kW and kWh Impact Claims Are as of April 30, 2007. Some Programs Ended Earlier, While Others Will Continue to Exhaustion of Funds.					
3rd Tranche of MARR					
Residential and Small Commercial					
Residential					
Co-Branded Mass Market	Apr-05	Apr-06	1.0	12	Start of program deployment and end of funding (program ended).
SMART Meter Pilot	Apr-05	Dec-05	0.8	9	Denotes end of deployment of 550 Smart Meters.
Residential Load Control	Apr-05	Jul-07	2.3	27	
SMART (Electric) Avenue	Apr-05	Sep-07	1.4	17	
Social Housing	Apr-05	na	1.5	18	Duration to date. Program still in progress.
Commercial, Industrial & Institutional					
Leveraging Energy Conservation (BIP)	Apr-05	Aug-06	1.3	16	
SMART Meter Commercial	Apr-05	Jul-06	1.3	15	
Load Control Initiative (DR)	Apr-05	na	1.5	18	Duration to date. Program still in progress.
On-the-Bill (Financing) Payment Plan	Apr-05	na	1.5	18	Duration to date. Program still in progress.
Distribution Loss Reduction					
Voltage Profile Management	Apr-05	na	1.5	18	Duration to date. Program still in progress.
Distributed Energy					
Load Displacement	Apr-05	na	1.5	18	Duration to date. Program still in progress.
Stand-by Generators (DR)	Apr-05	na	1.5	18	Duration to date. Program still in progress.
Incremental Funding Approved in Rates (2nd Generation)					
Residential Sector Program					
Water Heater Tune-ups	May-06	Aug-07	1.3	15	
Seasonal LED Exchange	May-06	Dec-06	0.6	7	
CFL Bulb Drop	May-06	na	1.4	17	Duration to date. Program still in progress.

ENERSOURCE - LRAM CALCULATIONS																
Based on Cumulative CDM Savings as of April 30, 2007																
Referenced to OEB Filing Requirements for Transmission and Distribution Applications - EB-2006-0170, November 14, 2006																
Board #49		Net kWh and kW Impacts (Net of Freeriders)														
	Energy			Summer On-Peak Demand			Distribution Volumetric Rate (Energy Based)			Distribution Volumetric Rate (Demand Based)			LRAM			
Time Periods Referenced to Applicable Distribution Rates	May 1, 2005 Apr 30, 2006	May 1, 2006 Oct 31, 2006	Nov 1, 2006 Apr 30, 2007	May 1, 2005 Apr 30, 2006	May 1, 2006 Oct 31, 2006	Nov 1, 2006 Apr 30, 2007	May 1, 2005 Apr 30, 2006	May 1, 2006 Oct 31, 2006	Nov 1, 2006 Apr 30, 2007	May 1, 2005 Apr 30, 2006	May 1, 2006 Oct 31, 2006	Nov 1, 2006 Apr 30, 2007	May 1, 2005 Apr 30, 2007	May 1, 2006 Oct 31, 2007	Nov 1, 2006 Apr 30, 2008	Total (All Periods)
Funding Mechanism, CDM Program & Customer Rate Class	(kWh)	(kWh)	(kWh)	(kW)	(kW)	(kW)	(\$/kWh)	(\$/kWh)	(\$/kWh)	(\$/kW)	(\$/kW)	(\$/kW)	(\$)	(\$)	(\$)	(\$)
3rd Tranche of MARR																
Residential and Small Commercial (<50 kW)							0.0103	0.0120	0.0121							
Residential																
Co-Branded Mass Market	1,416,460	7,956,951	8,972,375	575									\$ 14,590	\$ 95,483	\$ 108,566	\$ 218,639
SMART Meter Pilot	0			0									\$ -	\$ -	\$ -	\$ -
Residential Load Control			1,526,728			909							\$ -	\$ -	\$ 18,473	\$ 18,473
SMART (Electric) Avenue			4,262			32							\$ -	\$ -	\$ 52	\$ 52
Sub-Totals	1,416,460	7,956,951	10,503,366	575	0	941	0	0	0	0	0	0	\$ 14,590	\$ 95,483	\$ 127,091	\$ 237,164
GS <50 kW							0.0136	0.0146	0.0148							
Social Housing	46,171	96,362	224,509	3	9	15							\$ 628	\$ 1,407	\$ 3,323	\$ 5,358
Leveraging Energy Conservation (BIP)	0		12,687			3							\$ -	\$ -	\$ 188	\$ 188
On-the-Bill (Financing) Payment Plan	28,618			8									\$ 389	\$ -	\$ -	\$ 389
Sub-Totals	74,789	96,362	237,197	11	9	17							\$ 1,017	\$ 1,407	\$ 3,511	\$ 5,935
Commercial, Industrial & Institutional																
GS 50~499 kW										4.0296	4.3249	4.3715				
SMART Meter Commercial	573,958				25								\$ -	\$ 108	\$ -	\$ 108
Leveraging Energy Conservation (BIP)	0	81,877	3,262	0	25	45							\$ -	\$ 106	\$ 197	\$ 303
Load Control Initiative (DR)						235							\$ -	\$ -	\$ -	\$ -
On-the-Bill (Financing) Payment Plan	418,715			60									\$ 240	\$ -	\$ -	\$ 240
Sub-Totals	992,673	81,877	3,262	60	50	45							\$ 240	\$ 214	\$ 197	\$ 651
GS 500~4999 kW										1.5267	1.6657	1.6835				
SMART Meter Commercial													\$ -	\$ -	\$ -	\$ -
Leveraging Energy Conservation (BIP)	20,615	123,688	1,439,702	14	14	172							\$ 22	\$ 24	\$ 290	\$ 335
Load Control Initiative (DR)						2,350							\$ -	\$ -	\$ -	\$ -
On-the-Bill (Financing) Payment Plan													\$ -	\$ -	\$ -	\$ -
Sub-Totals	20,615	123,688	1,439,702	14	14	172							\$ 22	\$ 24	\$ 290	\$ 335
Large Users >5000 kW										2.5109	2.7524	2.7819				
Load Control Initiative (DR)						2,500							\$ -	\$ -	\$ -	\$ -
Distribution Loss Reduction																
Voltage Profile Management													\$ -	\$ -	\$ -	\$ -
Distributed Energy																
Stand-by Generators (DR)						6,205										
50~499 kW						105							\$ -	\$ -	\$ -	\$ -
500~4999 kW						4,100							\$ -	\$ -	\$ -	\$ -
>5000 kW						2,000							\$ -	\$ -	\$ -	\$ -
Incremental Funding Approved in Rates (2nd Generation)																
Residential Sector Program							0.0103	0.0120	0.0121							
Residential																
Water Heater Tune-ups		473,105	3,710,144		22	171							\$ -	\$ 5,677	\$ 44,893	\$ 50,570
Seasonal LED Exchange			103,700			0							\$ -	\$ -	\$ 1,255	\$ 1,255
CFL Bulb Drop		392,675	2,588,073		0	0							\$ -	\$ 4,712	\$ 31,316	\$ 36,028
Sub-Totals	0	865,780	6,401,917	0	22	171							\$ -	\$ 10,389	\$ 77,463	\$ 87,853
GRAND TOTALS by Rate Class																
Residential	1,416,460	8,822,731	16,905,283	575	22	1,111							\$ 14,590	\$ 105,873	\$ 204,554	\$ 325,016
Small Commercial GS<50 kW	74,789	96,362	237,197	11	9	17							\$ 1,017	\$ 1,407	\$ 3,511	\$ 5,935
CI&I 50~499 kW	992,673	81,877	3,262	60	50	150							\$ 240	\$ 214	\$ 197	\$ 651
500~4999 kW	20,615	123,688	1,439,702	14	14	4,272							\$ 22	\$ 24	\$ 290	\$ 335
>5000 kW	0	0	0	0	0	4,500							\$ -	\$ -	\$ -	\$ -
LRAM Grand Totals:	2,504,537	9,124,657	18,585,443	660	95	10,051							\$ 15,868	\$ 107,518	\$ 208,551	\$ 331,937

Freeridership Impact:
#REF!

ENERSOURCE - SSM CALCULATIONS														
Based on Cumulative CDM Savings as of April 30, 2007														
Referenced to OEB Filing Requirements for Transmission and Distribution Applications - EB-2006-0170, November 14, 2006														
Board #49	Net Savings (Net of Freeriders)													
	Energy (Annualized Savings)			Energy (Cumulative Totals)		Summer On-Peak Demand			SSM of PILs and Freeriders					(Net
	Time Periods Referenced to Applicable Distribution Rates	May 1, 2005 Apr 30, 2006	May 1, 2006 Oct 31, 2006	Nov 1, 2006 Apr 30, 2007	Annual	Lifecycle	May 1, 2005 Apr 30, 2006	May 1, 2006 Oct 31, 2006	Nov 1, 2006 Apr 30, 2007	CDM Spending	TRC Benefit	TRC Cost	TRC Net Benefit	SSM (@ 5% of Net Benefit)
Funding Mechanism, CDM Program & Customer Rate Class	(kWh)	(kWh)	(kWh)	(kWh)	(kWh)	(kW)	(kW)	(kW)	(\$)	(\$)	(\$)	(\$)	(\$)	(\$)
3rd Tranche of MARR														
Residential and Small Commercial (<50														
Residential														
Co-Branded Mass Market	4,543,448	11,235,722	1,200,169	16,979,339	117,122,260	578			\$ 846,393	\$ 6,993,621	\$ 1,138,920	\$ 5,854,701	\$ 292,735	
SMART Meter Pilot	0			0		0			\$ 251,215	\$ -	\$ -	\$ -	\$ -	
Residential Load Control			2,173,084	2,173,084	39,115,505			909	\$ 705,111	\$ 3,405,505	\$ 1,684,749	\$ 1,720,756	\$ 86,038	
SMART (Electric) Avenue			9,471	9,471	94,710			35	\$ 223,088	\$ 23,456	\$ 338,621	\$ (315,165)	\$ (15,758)	
Sub-Totals	4,543,448	11,235,722	3,382,724	19,161,893	156,332,475	578	0	944	\$ 2,025,807	\$ 10,422,582	\$ 3,162,290	\$ 7,260,292	\$ 363,015	
GS <50 kW														
Social Housing	47,306	183,010	141,639	371,956	3,196,445	3	10	16	\$ 120,465	\$ 259,238	\$ 207,870	\$ 51,367	\$ 2,568	
Leveraging Energy Conservation (BIP)	0		23,380	23,380	147,903			4	\$ 1,123	\$ 9,469	\$ 4,843	\$ 4,626	\$ 231	
On-the-Bill (Financing) Payment Plan			37,535	37,535	187,677	4		7	\$ 6,846	\$ 14,814	\$ 15,237	\$ (423)	\$ (21)	
Sub-Totals	47,306	183,010	202,555	432,871	3,532,025	8	10	27	\$ 128,434	\$ 283,521	\$ 227,950	\$ 55,570	\$ 2,779	
Commercial, Industrial & Institutional (>50														
GS 50-499 kW														
SMART Meter Commercial		459,532		459,532	6,892,979		30		\$ 246,995	\$ -	\$ -	\$ -	\$ -	
Leveraging Energy Conservation (BIP)	0	256,120	6,011	262,131	1,658,255	0	75	76	\$ 12,586	\$ 106,166	\$ 54,297	\$ 51,869	\$ 2,593	
Load Control Initiative (DR)				0	0			235	\$ 13,959	\$ 214,806	\$ 75,128	\$ 139,678	\$ 6,984	
On-the-Bill (Financing) Payment Plan			549,186	549,186	2,745,932	36		56	\$ 100,167	\$ 216,741	\$ 222,937	\$ (6,196)	\$ (310)	
Sub-Totals	0	715,652	555,198	1,270,849	11,297,165	36	105	132	\$ 373,706	\$ 537,712	\$ 352,361	\$ 185,351	\$ 9,268	
GS 500-4999 kW														
SMART Meter Commercial				0	0				\$ -	\$ -	\$ -	\$ -	\$ -	
Leveraging Energy Conservation (BIP)	227,933	227,933	5,058,397	5,514,263	34,883,528	24	24	553	\$ 264,758	\$ 2,233,340	\$ 1,142,198	\$ 1,091,141	\$ 54,557	
Load Control Initiative (DR)				0	0			2,350	\$ 139,585	\$ 2,148,059	\$ 751,278	\$ 1,396,781	\$ 69,839	
On-the-Bill (Financing) Payment Plan				0	0				\$ -	\$ -	\$ -	\$ -	\$ -	
Sub-Totals	227,933	227,933	5,058,397	5,514,263	34,883,528	24	24	553	\$ 404,343	\$ 4,381,398	\$ 1,893,476	\$ 2,487,922	\$ 124,396	
Large Users >5000 kW														
Load Control Initiative (DR)				0	0			2,500	\$ 148,495	\$ 2,285,169	\$ 799,232	\$ 1,485,937	\$ 74,297	
Distribution Loss Reduction														
Voltage Profile Management ⁽¹⁾				0	0				\$ 627,929	\$ -	\$ -	\$ -	\$ -	NA
Distributed Energy														
Load Displacement														
GS <50 kW				0	0				\$ 34,654	\$ -	\$ 34,654	\$ (34,654)	\$ (1,733)	
GS 50-499 kW				0	0				\$ 34,654	\$ -	\$ 34,654	\$ (34,654)	\$ (1,733)	
Sub-Totals				0	0				\$ 69,307	\$ -	\$ 69,307	\$ (69,307)	\$ (3,465)	
Stand-by Generators (DR)														
GS 50-499 kW				0	0			105	\$ 25,070	\$ 95,977	\$ 38,369	\$ 57,608	\$ 2,880	
GS 500-4999 kW				0	0			4,100	\$ 978,937	\$ 3,747,677	\$ 1,498,237	\$ 2,249,440	\$ 112,472	
Large Users >5000 kW				0	0			2,000	\$ 477,530	\$ 1,828,135	\$ 730,847	\$ 1,097,288	\$ 54,864	
Sub-Totals				0	0			6,205	\$ 1,481,537	\$ 5,671,789	\$ 2,267,454	\$ 3,404,335	\$ 170,217	
Overall Program Support														
Special Events Van (totalized under Co-Branded Mass Markets)				0	0								\$ -	\$ -
Program Support - Regulatory Reporting, Other				0	0				\$ 1,360,201		\$ 1,360,201	\$ (1,360,201)	\$ (68,010)	
Sub-Totals				0	0				\$ -		\$ -	\$ -	\$ -	
3rd Tranche of MARR Portfolio Totals	4,818,687	12,362,317	9,198,873	26,379,877	206,045,192	646	139	4,156	6,619,759	23,582,171	10,132,271	\$ 13,449,900	\$ 672,495	
Note: 1) Voltage Profile Management Program is not a customer focussed initiative and therefore it does not qualify for SSM claims.														
Incremental Funding Approved in Rates (2nd Generation)														
Residential Sector Program														
Residential														
Water Heater Tune-ups		1,547,870	3,082,819	4,630,689	36,448,797		72	140	\$ 480,334	\$ 3,009,201	\$ 480,334	\$ 2,528,868	\$ 126,443	
Seasonal LED Exchange				103,700	3,111,003			0	\$ 112,711	\$ 143,220	\$ 113,837	\$ 29,383	\$ 1,469	
CFL Bulb Drop		1,353,667	1,457,315	2,810,983	12,087,228			0	\$ 252,202	\$ 721,058	\$ 252,202	\$ 468,856	\$ 23,443	
Sub-Totals	0	2,901,537	4,643,834	7,545,372	51,647,028	0	72	140	\$ 845,247	\$ 3,873,480	\$ 846,373	\$ 3,027,107	\$ 151,355	
Incremental Funding (2nd Gen.) Totals	0	2,901,537	4,643,834	7,545,372	51,647,028	0	72	140	845,247	3,873,480	846,373	\$ 3,027,107	\$ 151,355	
CDM Portfolio-Based Totals by Rate Class														
Incremental Funding - Residential	0	2,901,537	4,643,834	7,545,372	51,647,028	0	72	140	\$ 845,247	\$ 3,873,480	\$ 846,373	\$ 3,027,107	\$ 151,355	
3rd Tranche - Residential	4,543,448	11,235,722	3,382,724	19,161,893	156,332,475	578	0	944	\$ 2,025,807	\$ 10,422,582	\$ 3,162,290	\$ 7,260,292	\$ 363,015	
Small Commercial GS<50 kW	47,306	183,010	202,555	432,871	3,532,025	8	10	27	\$ 163,087	\$ 283,521	\$ 262,604	\$ 20,917	\$ 1,046	
CI&I 50-499 kW	0	715,652	555,198	1,270,849	11,297,165	36	105	237	\$ 433,430	\$ 633,690	\$ 425,384	\$ 208,306	\$ 10,415	
500-4999 kW	227,933	227,933	5,058,397	5,514,263	34,883,528	24	24	4,653	\$ 1,383,280	\$ 8,129,075	\$ 3,391,713	\$ 4,737,361	\$ 236,868	
>5000 kW	0	0	0	0	0	0	0	4,500	\$ 626,025	\$ 4,113,304	\$ 1,530,079	\$ 2,583,224	\$ 129,161	
Program Support - Regulatory Reporting, C	0	0	0	0	0	0	0	0	1,360,201	0	1,360,201	\$ (1,360,201)	\$ (68,010)	
CDM Portfolio-Based SSM Totals	4,818,687	15,263,854	13,842,707	33,925,249	257,692,220	646	210	10,501	\$ 6,837,077	\$ 27,455,651	\$ 10,978,645	\$ 16,477,007	\$ 823,850	

Co-Branded Mass Market Program - Water Heater Tune-up

Program Report
2005-2006 Summary as of Apr 30

0.772 m/C

Activities Under Program/Initiative	2004-2005 Totals	2006 Totals	Totals to-Date
Appointments commercial:	0	24	24
Appointments Residential:	1,200	397	1,597
Water heater insulation blankets size 40:	1,200	173	1,373
Water heater insulation blankets size 60:	0	176	176
Water heater insulation blanket size 100:	0	4	4
Tank Already Wrapped	0	4	4
Piping (m): ³	0	307	307
CFL Light Bulbs Installed:			
CFL-20W (75W):	0	0	0
CFL-15W (60W):	0	0	0
CFL-13W (60W):	0	0	0
CFL Light bulbs Left:			
CFL-20W (75W):	0	573	573
CFL-15W (60W):	0	56	56
CFL-13W (60W):	4,800	1,117	5,917
Aerator left:	3,600	346	3,946
Aerator installed:	0	116	116
Normal Shower Heads Installed:	0	175	175
Normal Shower Heads left:	1,200	83	1,283
Extending Shower Heads Installed:	0	50	50
Extending Shower Heads left:	0	84	84
Notes and General Comments:			374
¹ . Based on Average Annual Consumption of 10,000 kWh per Household			
² . Avoided CO ₂ Emissions are based on 974 g/kWh, the CO ₂ -kWh Equivalence for Ontario, as given in the <u>2005 OPG Sustainable Development Report</u>			
³ . OEB Measures List-Prescribed Piping Insulation Savings are per average 6'-10' per home. Say 8 ft/Tune-up. Multiplier to convert metres of insulated piping into equivalent # of 8ft lengths for savings calculation:			0.410

RESOURCE SAVINGS CALCULATIONS								
3rd Tranche Funding - to April 30, 2006 (See 2nd Gen-Supplemental for additional results)								
Savings Factors Per Unit			2006 Annual Savings			Program Savings to-Date		
Summ. On-Peak Demand Savings	Annual Energy Savings	Annual Water Savings	Summ. On-Peak Demand Savings	Annual Energy Savings	Annual Water Savings	Summer On-Peak Demand Savings	Annual Energy Savings	Annual Water Savings
(kW)	(kWh)	(L)	(kW)	(kWh)	(m3) (1,000 L)	(kW)	(kWh)	(m3) (1,000 L)
0.019	270		3.3	46,693	0	26.1	370,573	0
0.019	270		3.3	47,502	0	3.3	47,502	0
0.019	270		0.1	1,080	0	0.1	1,080	0
			0.0	0	0	0.0	0	0
/8'	76		0.6	9,553	0	0.6	9,553	0
0.000	128		0.0	0	0	0.0	0	0
0.000	104		0.0	0	0	0.0	0	0
0.000	109		0.0	0	0	0.0	0	0
0.000	128		0.0	73,115	0	0.0	73,115	0
0.000	104		0.0	5,846	0	0.0	5,846	0
0.000	109		0.0	121,798	0	0.0	645,190	0
0.002	34	3,269	0.7	11,591	1,131	7.9	132,191	12,899
0.002	34	3,269	0.2	3,886	379	0.2	3,886	379
0.039	546	26,800	6.8	95,480	4,690	6.8	95,480	4,690
0.039	546	26,800	3.2	45,285	2,224	50.0	700,005	34,384
0.039	546	26,800	2.0	27,280	1,340	2.0	27,280	1,340
0.039	546	26,800	3.3	45,830	2,251	3.3	45,830	2,251
TOTALS:	24	534,939	12,016	100	2,157,531	55,944		
Per Single Tune-up:	1,271		29	0.06	1,331	35		
Percent kWh Savings per Household	12.7%				13.3%			
Households Potentially Supplied by Savings: ¹	53				216			

Avoided CO₂ Annual Emissions:²	521 tonnes	2,101 tonnes

Quarterly Reports to OEB:

Q4-06 TOTALS:	24	534,939	12,016	100	2,157,531	55,944
Q3-06 TOTALS:	93	1,953,843	43,013	169	3,577,635	86,942
Q2-06 TOTALS:	53	1,193,888	24,435	129	2,817,680	68,364
3rd Tranche Results (to End of April)	24	534,970	12,016	101	2,158,762	55,944
Q1-06 TOTALS:	14	328,712	7,322	91	1,952,504	51,250

2005 OEB CDM Report:	1,482,000	0

Co-Branded Mass Market Program - Water Heater Tune-up

Monthly Report
Apr-06

Summary of Month:	Week 1	Week 2	Week 3	Week 4	Totals	Unit kW	On- Peak kW/unit	Unit kWh/y	Water L/y/unit	On- Peak kW	Saved kWh/y	Water L/y
Appointments commercial:	2	2	2	6	12							
Appointments Residential:	48	39	29	33	149							
Water heater insulation blankets size 40:	17	31	21	17	86		0.019	270		2	23,211	0
Water heater insulation blankets size 60:	30	14	14	19	77		0.019	270		1	20,782	0
Water heater insulation blanket size 100:	0	0	0	0	0		0.019	270		0	0	0
Tank Already Wrapped	2	2	0	0	4					0	0	0
Piping (m):	34	35	31.5	33.5	134		0.005	76		1	10,184	0
CFL Light Bulbs Installed:												
CFL-20W (75W):	0	0	0	0	0		0.000	128		0	0	0
CFL-15W (60W):	0	0	0	0	0		0.000	104		0	0	0
CFL-13W (60W):	0	0	0	0	0		0.000	109		0	0	0
CFL Light bulbs Left:												
CFL-20W (75W):	0	0	0	0	0		0.000	128		0	0	0
CFL-15W (60W):	0	0	0	0	0		0.000	104		0	0	0
CFL-13W (60W):	188	160	124	149	621		0.000	109		0	67,714	0
Aerator left:	45	33	24	37	139		0.002	34	3,269	0	4,657	454,391
Aerator installed:	2	8	7	1	18		0.002	34	3,269	0	603	58,842
Normal Shower Heads Installed:	36	32	25	33	126		0.039	546	26,800	5	68,746	3,376,800
Normal Shower Heads left:	5	3	3	6	17		0.039	546	26,800	1	9,275	455,600
Extending Shower Heads Installed:	4	6	2	0	12		0.039	546	26,800	0	6,547	321,600
Extending Shower Heads left:	1	0	0	0	1		0.039	546	26,800	0	546	26,800
TOTALS:										10.165	212,265	4,694,033
Per single Tune-up: / 161 Tune										0.063	1,318	29,155
General Comments:												
Gas Water Heaters	2	4	2	3	11							
Water Heaters Already Insulated					-							
Interested in Programmable Thermostats				1	1							
Other (specify and give numbers, if applicable)					-							
					-							
					-							
					-							
					-							
					-							

Capital Investment and Calculation of Amortization and Net Fixed Assets

Actual						
Gross Assets						Gross Assets for SMRA
Meters		2006	2007	2008	2009	Capital
2006	\$ 1,587,158	23,545	105,811	105,811	-	1,587,158
2007	\$ 8,424,082		140,401	561,605	-	8,424,082
2008	\$ 12,200,973			203,350	-	6,100,487
	\$ -	-	-	-	-	-
	\$ 22,212,213	26,453	246,212	870,766	-	16,111,727
Hardware		2006	2007	2008	2009	
2006	\$ 40,439	6,437	8,088	8,088	-	40,439
2007	\$ 214,876		10,744	42,975	-	214,876
2008	\$ -			-	-	-
	\$ -	-	-	-	-	-
	\$ 255,315	2,022	18,832	51,063	-	255,315
Software		2006	2007	2008	2009	
2006	\$ 97,230	23,858	32,410	32,410	-	97,230
2007	\$ 437,500		36,458	145,833	-	437,500
2008	\$ 43,059			3,588	-	21,530
	\$ -	-	-	-	-	-
	\$ 577,789	8,103	68,868	181,832	-	556,260
					Total	16,923,301

2006 RATE YEAR NFA			2007 RATE YR NFA		2008 NFA	Cumulative	
2006	2006 in 2007	2006 in 2008	2007	2007 in 2008	2008	2007 NFA	
1,563,613						1,563,613	2006
	1,457,802		8,283,681			9,741,483	2007
		1,351,992		7,722,075	5,897,137	14,971,204	2008
34,002						34,002	2006
	25,914		204,132			230,046	2007
		17,826		161,157	-	178,983	2008
73,372						73,372	2006
	40,962		401,042			442,004	2007
		8,552		255,208	17,941	281,702	2008
						-	
1,670,987	1,524,679	1,378,370	8,888,855	8,138,441	5,915,078	27,516,409	

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FINANCIAL MARKETS MONTHLY

July 2007

Back-to-back losses for Canadian and U.S. bond holders

Canadian and U.S. bond markets posted losses for the second consecutive month as investors grappled to get a handle on the true momentum of the two economies. After yields rose to multi-year highs mid-month, sellers of Canadian bonds took a breather and interest rates edged down in the second half of June. U.S. Treasury yields faded back as well after bursting higher in early June but remain at the high end of this year's trading range. Uncertainty about the depth of the U.S. housing market slowdown and the implications for the broader U.S. economy and a run of slightly softer Canadian data saw investors reassess the outlook for central bank policy this year.

Our forecast is little changed. We look for the Bank of Canada to raise the overnight rate to 5% by year-end and 5.25% in early 2008, more than is currently priced into the market. The Federal Reserve is expected to hold the funds rate at 5.25% this year with the next move likely to be a rate hike in early 2008, which is also a more aggressive forecast than is priced into financial markets. Yields are expected to trend higher in the second half of 2007 with the 10-year Canadian yield forecast to rise to 5.15% and the 10-year U.S. Treasury rate to 5.50%.

Global central banks to keep rates moving up

The Bank of England and the European Central Bank (ECB) are expected to continue to push interest rates higher as strong domestic growth keeps risks to the inflation outlook to the upside. RBC Economics now expects the Bank of England to raise the policy rate to 5.75% in July with another 25 basis-point hike likely in November.

The ECB appears to be determined to shift policy out of its current accommodative stance and we expect they will continue with their quarter-point-per-quarter hiking regime until the middle of 2008 when the rate reaches 5.00% from 4.00% currently.

Central bank watch

Short-term bias



Even the mixed tone in economic data will not be enough to deter the Bank of Canada from raising rates this month given the elevated level of core inflation.



The U.S. economy likely rebounded in the second quarter, but housing remains a downside risk although some signs of stability are starting to emerge. Even the moderation in the core inflation rate will not be enough to jar the Fed out of its steady-as-she-goes policy stance.



The Bank of Japan expects the economy to continue to expand and inflation to return to zero in the near-term. Both will have to occur before a rate increase will be announced.



Recent hawkish statements from the Bank of England point to rates moving up in July as policymakers work to prevent another uptick in inflation.



Comments from members of the ECB characterize policy as accommodative, providing support to our view that the quarter-per-quarter rate hike campaign will continue until mid-2008.

Highlights

▲ Sellers of Canadian bonds take a breather as economic data for April and May present mixed picture.

▲ Canadian data reports show headline weakness, but underlying details still indicate that the economy has good momentum.

▲ Even the core inflation rate faded in May, but the reprieve will likely be short-lived and won't deter the Bank of Canada from raising interest rates.

▲ Canada's policy rate is below its neutral setting and will need to become slightly restrictive if the 2% inflation target is to be met.

▲ We expect 75 basis points of rate increases by the Bank of Canada this year and 25 basis points in 2008 — a more aggressive forecast than is priced into the futures market.

▲ Canadian bond yields will continue to grind higher in 2007 and peak around 5.40% in mid-2008.

Canada's economy still has solid momentum

Canada's economy enjoyed strong momentum going into the second quarter, but mixed data for April and May resulted in a downward revision to the market's forecast for the degree of monetary policy tightening in the pipeline. The pace of job creation paused in April and May, although the unemployment rate held at its 33-year low and wage growth firmed, signalling that labour market conditions are tight. April's headline numbers in the manufacturing, retail and wholesale reports were disappointing, although manufacturing and retail activity actually firmed in the month after adjusting for price changes; only wholesalers saw a big dip in sales.

Real GDP growth flattened out in April compared to the rapid gains in February and March, but even with only a modest pick-up in May and June the economy is on track to grow at close to its potential rate in the second quarter. After the strong increase in the first quarter and with the economy already operating in a state of excess demand, a trend-like increase in the second quarter spells no relief from the upward pressure being exerted on prices. This means that the Bank will have to raise the overnight rate if the medium-term inflation target is to be met.

Canada's inflation reprieve likely to be short-lived

Canada's core inflation rate edged back down to 2.2% in May after hitting a four-year high of 2.5% in April. The monthly core rate increase of 0.3% was below the rapid 0.5% increase recorded last May, but faster than April's 0.2% rise and almost double the average monthly pace in the core rate in the past two years, indicating that upward price pressures are not abating. Even if the CPIX goes up by the average rate that it increased during the past seven Junes, the year-over-year core inflation rate would be 2.6% — the fastest pace of increase since March 2003 and reaching toward the 3% upper limit of the Bank of Canada's 1% to 3% control target band.

Bank of Canada to push overnight rate above neutral to ensure inflation meets target

With Canada's core inflation rate holding above the mid-point of the 1% to 3% target band, and the economy showing solid growth momentum, the Bank of Canada would like to lift its policy rate above the current 4.25% to a less neutral stance to ensure that inflation heads back down to the 2% target in the medium-term. An estimate of Canada's neutral policy rate can be derived as the sum of the economy's potential output growth rate plus inflation. In its April *Monetary Policy Report*, the Bank of Canada re-estimated the economy's potential growth rate to 2.6% for the period from 2004 to 2006. This was a downgrade from their previous assumption that the economy's speed limit was closer to 3%, reflecting weaker-than-expected productivity growth. Combined with a 2% inflation rate, Canada's neutral policy rate is estimated at 4.5%, meaning that the current overnight rate stands on the easier side of neutral. If productivity growth were to strengthen, an even higher neutral policy rate would be implied.

Canadian bond yields to trend higher this year and first half of 2008

With the Bank set to restart its rate hiking regime this month, we expect that yields on government bonds will resume their upward march. The market is priced for two 25 basis-point increases, but we think that there will be three hikes before the end of 2007. We forecast that two-year yields will end 2007 at 5.10% with 10-year rates at 5.15%. Another increase in the overnight rate in early 2008 to 5.25% will give yields another upward push and we forecast that two-year bond yields will peak at around 5.40% in the middle of next year and that the 10-year rate will rise to 5.45%.

U.S. economy showing signs of life

The U.S. economy is showing signs of a solid rebound after the first-quarter's disappointing performance. The ISM surveys are pointing to strengthening business activity and consumers are still spending, albeit at a somewhat slower pace than in the six months spanning late 2006 to early 2007. Our tracking of the U.S. economy points to a solid 3.5% annual rate increase in second-quarter GDP, a marked improvement from the first-quarter's 0.7% pace. Labour market conditions remain tight and the number of jobs created perked up again in May. Employment growth slowed in 2007 compared to the strong gains reported in 2006, but the softening has not been dramatic enough to moderate wage growth or to put very much upward pressure on the unemployment rate. This means that one of the key supports for consumer spending remains in place.

The U.S. housing market, however, remains soft. The level of existing home sales is low, inventories of unsold units high and home prices continue to decline. The NAHB's index of homebuilder sentiment also weakened further in the second quarter. Still, the May new home sales report showed some tentative signs that the weakness may be easing as the average level of sales so far this quarter is higher than the first-quarter average and inventories are down from the recent peak. The housing starts data also showed signs of bottoming out with starts having firmed in the April and May period compared to the first-quarter average, pointing to a quarterly increase for the first time in the past five quarters.

Housing market uncertainty boosts financial market volatility

The ups and downs in the housing market data injected volatility into financial markets — the VIX index jumped back up to a four-month high in June — on worries about the flow-through to other areas of the economy or spinoffs into credit markets. We still view housing-sector weakness as likely to remain confined to the housing market alone and believe that the downward pressure will ease later this year and into 2008. Against this backdrop, we see little scope for U.S. policymakers to ease up on interest rates and are holding to our forecast that the Fed will raise the funds target to 5.75% early next year.

Core inflation slows, but upside risks remain

Core inflation slowed during the past three months with the core CPI easing to 2.2% in May, well down from the recent peak of 2.9% in September 2006, although holding at the higher end of what is presumed to be the Fed's target range. To be sure, policymakers may take some comfort from the recent moderation in core price inflation. However, indications that input prices remain elevated, with the prices paid indices in the business surveys elevated and wages growing at a healthy clip, will likely keep the Fed focussed on the upside risks to the inflation outlook, especially given the improvement in second-quarter growth prospects.

Fed to shift to slightly restrictive policy in 2008

For now, we expect that the cross currents in the economy will keep the Fed on the sidelines. U.S. interest rates have come off their recent highs as investors repriced their expectations that the Fed will lower the funds rate later this year. The market now gives about a 20% chance of a 25 basis-point rate cut this year. In contrast, we expect that the Fed will keep the funds rate at 5.25% in 2007 as the economy accelerates and inflation risks persist. Two 25 basis-point hikes to 5.75% are likely in the first half of 2008 as the Fed brings monetary policy to the tight side of its neutral range. We have made modest upward revisions to our forecast for U.S. market interest rates, with two-year rates expected to hit 5.40% in the final quarter of 2007 and 10-year rates rising to 5.50%. We look for the peak in yields about the middle of 2008 (two-year and 10-year yields at 5.8%), but then for rates to drift down to 5.55% in the two-year maturity with the 10-year rate at 5.75%.

Highlights

▲ The U.S. economy is showing signs of a solid rebound after the first-quarter's disappointing performance.

▲ Our tracking of the U.S. economy points to a solid 3.5% annual rate increase in second-quarter GDP, a marked improvement from the first-quarter's 0.7% pace.

▲ Core inflation has moderated, but upside risks exist.

▲ The Fed is assessing whether the housing market weakness will remain isolated or whether it presents a risk to the overall economy or other credit markets.

▲ We believe that the problem is restricted to the housing market and that there will be limited flow-through effects.

▲ The Fed is likely to keep rates steady this year but will increase the funds target rate by 50 basis points in the first half of 2008 as concerns about the housing market ease.

Interest rate outlook

%, end of period

		Actual		Forecast					
		07Q1	07Q2	07Q3	07Q4	08Q1	08Q2	08Q3	08Q4
Canada	Overnight	4.25	4.25	4.75	5.00	5.25	5.25	5.25	5.25
	Three-month	4.17	4.43	4.80	5.05	5.20	5.30	5.30	5.30
	Two-year	3.98	4.61	4.90	5.10	5.30	5.40	5.25	5.20
	Five-year	4.02	4.58	5.00	5.15	5.30	5.45	5.40	5.30
	10-year	4.13	4.59	5.00	5.15	5.30	5.45	5.45	5.40
	30-year	4.21	4.51	4.85	5.10	5.25	5.45	5.45	5.45
United States	Fed funds	5.25	5.25	5.25	5.25	5.50	5.75	5.75	5.75
	Three-month	4.92	4.69	5.00	5.25	5.45	5.75	5.70	5.65
	Two-year	4.60	4.93	5.20	5.40	5.65	5.80	5.65	5.55
	Five-year	4.55	4.97	5.35	5.45	5.65	5.80	5.75	5.60
	10-year	4.65	5.06	5.35	5.50	5.65	5.80	5.80	5.75
	30-year	4.83	5.16	5.45	5.60	5.75	5.90	5.85	5.80
Japan	Call	0.50	0.50	0.75	0.75	1.00	1.25	1.25	1.25
	Two-year	0.84	1.05	1.00	1.15	1.25	1.50	1.50	1.40
	10-year	1.66	1.87	2.00	2.25	2.25	2.25	2.35	2.35
United Kingdom	Repo	5.25	5.50	5.75	6.00	6.00	6.00	6.00	6.00
	Two-year	5.43	5.77	6.00	6.10	6.15	6.15	6.00	5.85
	10-year	4.94	5.44	5.45	5.45	5.60	5.60	5.65	5.65
Eurozone	Minimum bid	3.75	4.00	4.25	4.50	4.75	5.00	5.00	5.00
	Two-year	4.00	4.45	4.65	4.75	4.95	5.00	4.90	4.80
	10-year	4.05	4.55	4.65	4.70	4.90	4.95	4.95	4.90
Australia	Cash target rate	6.25	6.25	6.25	6.50	6.75	6.75	6.75	6.75
	Two-year	6.30	6.40	6.50	6.60	6.70	6.60	6.50	6.50
	10-year	5.88	5.95	6.10	6.50	6.85	6.90	6.80	6.70
New Zealand	Cash target rate	7.50	8.00	8.25	8.25	8.25	8.25	8.25	8.25
	Two-year	6.91	7.35	7.45	7.50	7.50	7.40	7.40	7.40
	10-year	5.92	6.40	6.70	6.90	7.05	7.10	7.00	6.80

Inflation watch

		Measure	Current period	Month ago	Year ago	3-month trend	6-month trend
Canada	Bank of Canada core CPI ¹		May	0.3	2.2	2.6	2.2
United States	Core PCE ²		May	0.1	1.9	2.5	1.9
United Kingdom	All-items CPI		May	0.3	2.5	2.8	2.8
Eurozone	All-items CPI		May	0.2	1.9	1.9	1.9
Japan	All-items (excl. fresh food)		May	0.1	-0.1	-0.2	0.0
Australia	Trimmed mean		2007Q1	0.5	2.9	NA	NA
New Zealand	CPI		2007Q1	0.5	2.5	NA	NA

¹Seasonally adjusted measurement

²Personal consumption expenditures less food and energy price indices

Central bank policy rates

		Current	Last			Current	Last
United States	Fed funds	5.25%	5.00%	June 29, 2006	Eurozone	Min. bid rate	4.00% 3.75%
Canada	Overnight rate	4.25%	4.00%	May 24, 2006	Australia	Cash rate	6.25% 6.00%
Japan	Call rate	0.50%	0.25%	Feb 21, 2007	New Zealand	Cash rate	8.00% 7.75%
United Kingdom	Repo rate	5.50%	5.25%	May 10, 2007			

Currency outlook

%, end of period

	Actual		07Q3	07Q4	08Q1	08Q2	08Q3	08Q4
	07Q1	07Q2						
Canadian dollar	1.15	1.06	1.04	1.06	1.08	1.09	1.10	1.12
Euro	1.33	1.36	1.37	1.38	1.35	1.35	1.34	1.33
U.K. pound sterling	1.96	2.01	2.04	2.03	1.99	1.99	1.94	1.93
New Zealand dollar	0.71	0.75	0.82	0.79	0.77	0.75	0.73	0.72
Japanese yen	118.3	122.0	124.0	126.0	125.0	123.0	121.0	120.0
Chinese renminbi	7.73	7.62	7.45	7.35	7.30	7.25	7.15	7.10
Australian dollar	0.81	0.83	0.87	0.89	0.88	0.86	0.85	0.84
Mexican peso	11.00	10.90	11.10	11.15	11.20	11.22	11.27	11.30

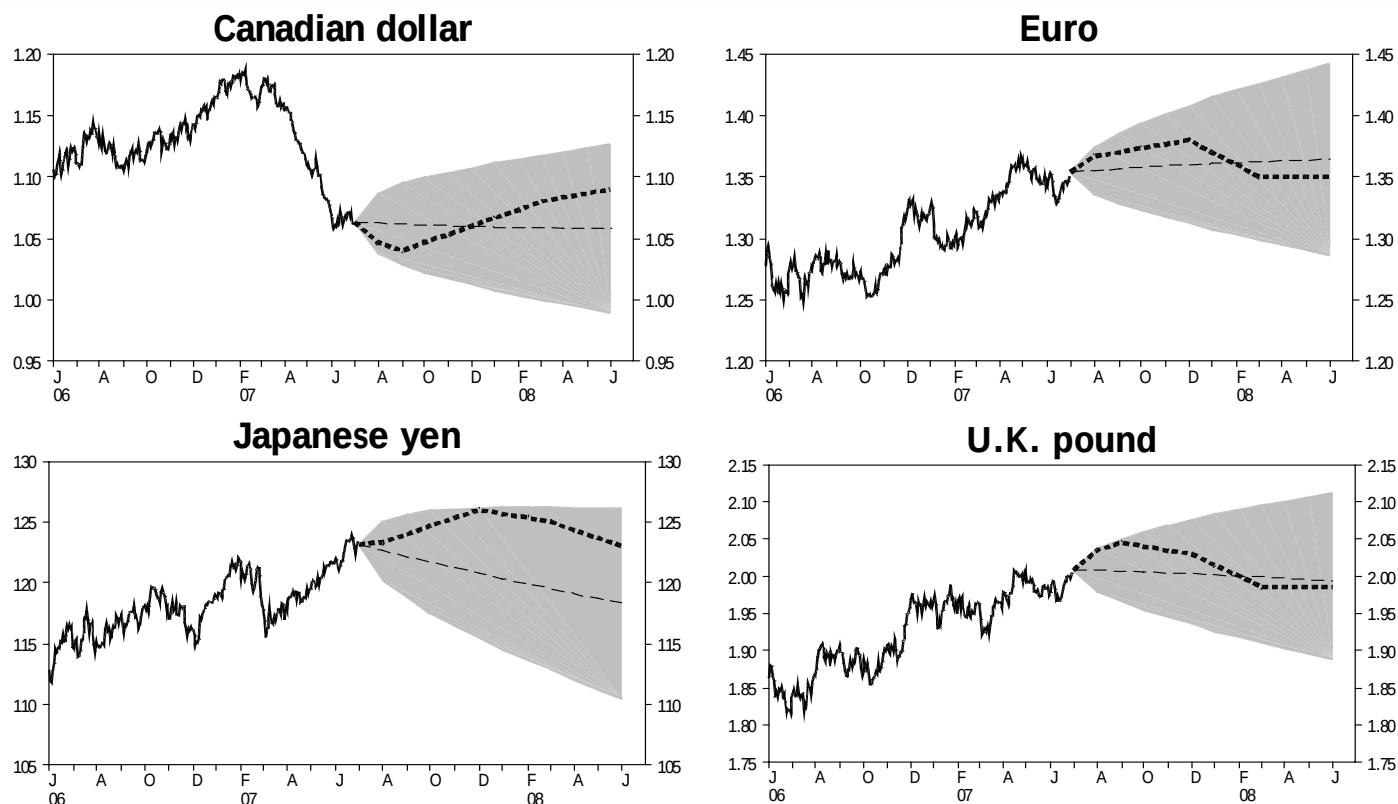
Canadian dollar cross-rates

	07Q1	07Q2	07Q3	07Q4	08Q1	08Q2	08Q3	08Q4
EUR/CAD	1.54	1.44	1.42	1.46	1.46	1.47	1.47	1.49
GBP/CAD	2.26	2.14	2.13	2.15	2.14	2.16	2.14	2.16
NZD/CAD	0.82	0.80	0.85	0.84	0.83	0.82	0.80	0.81
CAD/JPY	102.4	115.1	119.2	118.9	115.7	112.8	110.0	107.1
AUD/CAD	0.93	0.88	0.90	0.94	0.95	0.94	0.94	0.94

Rates are expressed in currency units per US\$ and currency units per CDN\$, except the euro, UK pound , Australian dollar and New Zealand dollar, which are expressed in US\$ per currency unit and CDN\$ per currency unit.

RBC Economics outlook relative to the market

These charts track historical exchange rates plus the forward rate (dashed line) relative to the RBC Economics forecast (dotted line) out one year. The cone for the forecast period frames the forward rate with confidence bounds using implied option volatilities as of the date of publication.



Central bank watch

Policy bias tighter ↗ easier ↘ neutral ↔

Bank of Canada

3M

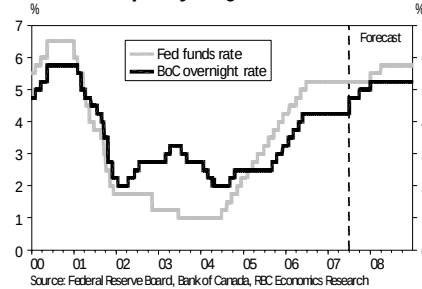


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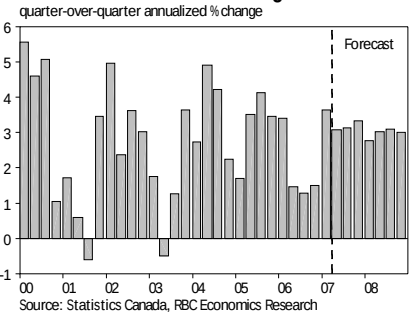


- The risk that inflation will remain in the upper end of the Bank of Canada's target band will put policymakers back into rate hike mode in July.
- We expect the Bank to boost the policy rate to 5.25% to ensure that growth slows enough to curtail upward inflation pressures.

Canadian and U.S. central bank policy target rates



Canadian real GDP growth



Federal Reserve

3M

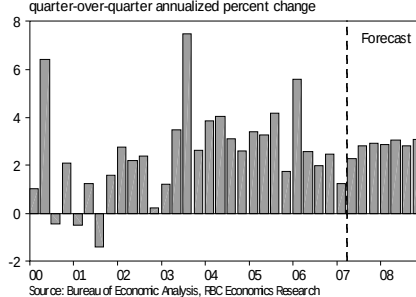


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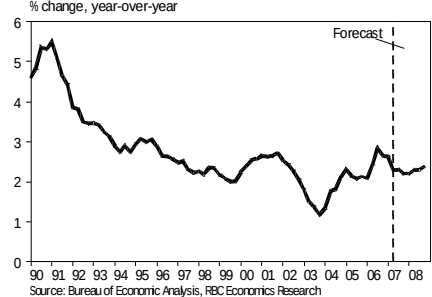


- Although core inflation has moderated, strong wage growth along with elevated input prices will keep the Fed on the sidelines this year.
- A stronger U.S. economy and persistent upward inflation pressures will likely see the Fed hike rates early next year.

U.S. real GDP growth



U.S. core CPI inflation



Bank of Japan

3M

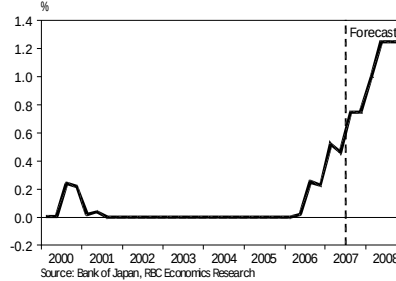


12M



- Once inflation moves back above zero, the Bank of Japan is likely to start hiking rates again.
- Policymakers will deliberately keep the pace of rate increases slow in order to ensure that the economy remains on a firm path

Japan overnight call rate



Japan core CPI inflation*



European Central Bank

3M

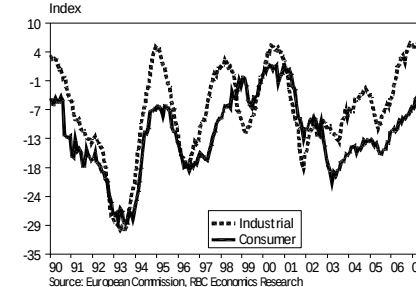


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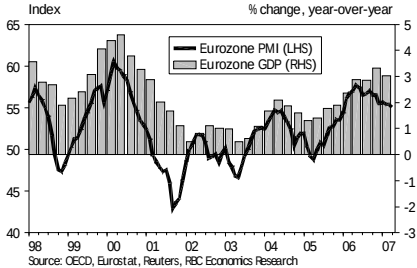


- The ECB is expected to continue to raise rates as inflation risks are skewed to the upside and monetary policy remains stimulative.
- We expect that policymakers will raise the policy rate to 5% by mid-2008 to nip upward inflationary pressures in the bud.

Eurozone confidence



Eurozone purchasing managers index with GDP



Bank of England

3M



12M

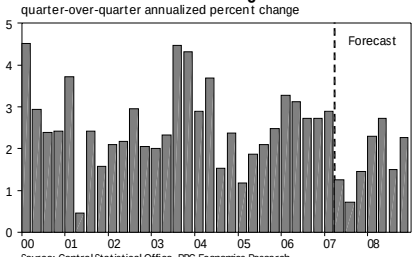


- The Bank of England has adopted a more aggressive tone and we now expect a 25 basis-point rate hike in July with another boost likely in November.
- Inflation is expected to settle at 2% in 2008 with the policy rate holding at 6%.

U.K. nationwide house prices



U.K. real GDP growth



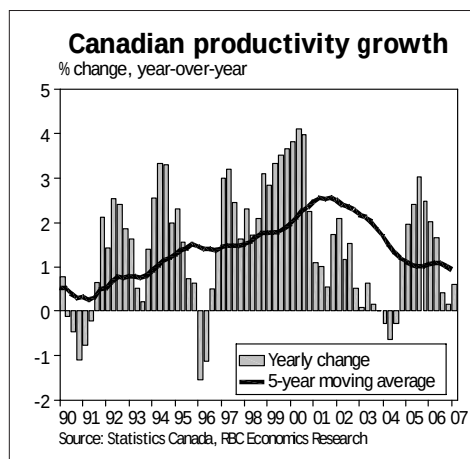
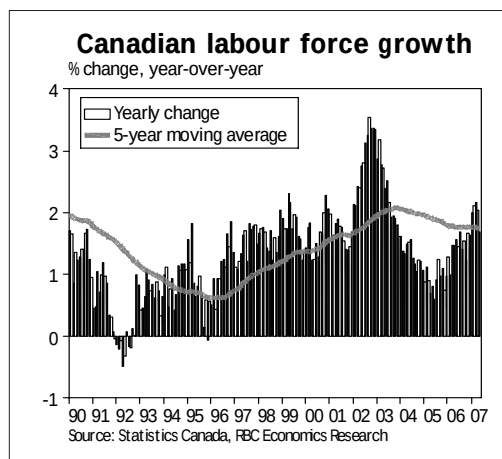
Forecast of key indicators

	Real GDP				Inflation			
	2005	2006	2007	2008	2005	2006	2007	2008
Canada	3.1	2.8	2.6	2.9	2.2	2.1	2.4	2.2
United States	3.2	3.3	2.2	2.9	3.4	3.2	2.8	2.8
Japan	1.9	2.2	2.1	2.2	-0.3	0.2	0.2	0.5
United Kingdom	1.8	2.8	2.2	1.9	1.9	2.6	2.0	2.0
Eurozone	1.7	2.5	2.8	2.2	2.2	2.2	2.2	2.0
Australia	2.8	2.7	3.6	3.7	2.7	3.5	2.1	2.8
New Zealand	2.2	1.5	2.7	2.9	3.0	3.4	2.2	2.7

Canadian real rates still historically low

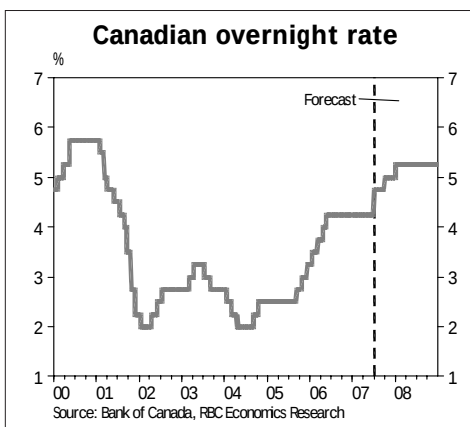
The robust growth in Canada's labour force is likely to slow given record-high participation rates and demographic factors...

... while productivity growth is expected to ramp up after four years of strong investment.



Real short-term interest rates in Canada are relatively low, fuelling strong consumer spending and business investment activity.

The Bank of Canada wants to shift the overnight rate to a more restrictive level to make sure that inflation heads back toward the 2% mid-point of the target band.



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Consumers Council of Canada Interrogatories

Interrogatory

A/S12/T7

#1. Please provide the 2006 Board Approved Rate Base levels for 2006.

Response

Please see attached excel spreadsheet which includes Approved 2006 EDR Rate Base.
Please note that 2006 EDR application was based on 2004 actuals as Enersource filed on a historical test year basis.

Interrogatory

B/S1/T1/p.2

#2. The evidence states that Enersource is forecasting late payment charges of \$420,000. Please provide the actual late payment revenue for the last 5 years. Please explain, in detail, how the forecast was derived.

Response

Enersource has forecasted the 2008 late payment charges based on the expected level of customers that will fail to pay their bills on time. The 2008 Test Year amount was held constant to the 2007 forecast. The actual late payment percentage charged is based on the current OEB approved rate of 1.5% / month. Enersource has subtracted the estimated late payment revenue from the 2008 Revenue requirement collected through distribution rates. The amount collected from late payment charges for 2004-2008 is set out below (all amounts in 000's):

	2004		2005		2006		2007		2008
\$	404	\$	363	\$	351	\$	420	\$	420

Interrogatory

B/S2/T1/p.2

#3. Enersource has assumed a 1% average growth rate for the number of customers based, in part, on the City of Mississauga's economic planning forecasts and past experience. Please provide evidence to support the use of the City's economic planning forecast as the basis for forecasting customer growth. In effect, please demonstrate that this data is a good indicator of electricity customer growth. Please provide forecast and actual growth rates developed by the City for the past 5 years.

Response

Please refer to the response to CCC interrogatory # 9; it provides information on the accuracy of Enersource's load forecast. The evidence reference provided notes that Enersource relies on the City of Mississauga's economic planning forecast issued by the City's Planning and Building Department in combination with Enersource's past experience to forecast number of customers. Enersource does not have information on the accuracy of the City's economic planning forecast as a basis for forecasting number of customers.

Interrogatory

B/S2/T1/p.2

#4. Please explain, specifically, how the 1% average growth rate was determined.

Response

This is based on past trend analysis and the City of Mississauga's economic planning forecast. Please see the attached spreadsheet, from 2004 onward Enersource has experienced approximately 1% growth rate in number of customers which aligns with the City of Mississauga economic planning forecasts.

Interrogatory

B/S2/T1/p. 2 and T2/p.2

#5. Enersource is projecting an additional 3315 residential customers residing in condominium units. Please explain, specifically, how this forecast was developed and how it is used to develop the overall load forecast. What is the average use assumed for these customers? Does it differ from other residential customers? If so, how does it differ? If not, why not?

Response

In 2008, Enersource proposes to install meters as follows:

- 2,100 in newly constructed condominium units; and
- 4,020 retrofitted condominium units

The average (based on monthly assumed additions per installed smart meters) of these customers for the 2008 test year is 3,155; this amount was added to Enersource's customer growth projections for the residential customer class.

The average use assumed for these customers is 500 kWh / month.

Yes, it is somewhat lower than the average residential customer's monthly consumption of approximately 800 kWh.

Interrogatory

B/S2/2/p.2

#6. Please describe, in detail, how the energy forecast has been adjusted to “explicitly incorporate the effect of the initiatives underway to create a Conservation Culture.” What process did the CDM Staff go through to provide estimates of the energy savings anticipated in 2008?

Response

[Please see the response to Board Staff interrogatory # 20.](#)

Interrogatory

B/S2/T5b

#7. With respect the schedule “Specific Service Charges 2006-2008” please provide the Board approved amounts for 2006.

Response

Attached is a list of Board approved Specific Service Charges. The Board approves the amount per charge, not the amount of revenue earned from the charges. The forecasted amount of revenue earned from these charges is and was subtracted from Enersource’s distribution revenue requirement in 2006 and in the 2008 test year.

See Attached spreadsheet as per 2006 EDR.

Interrogatory

B/S3/T1

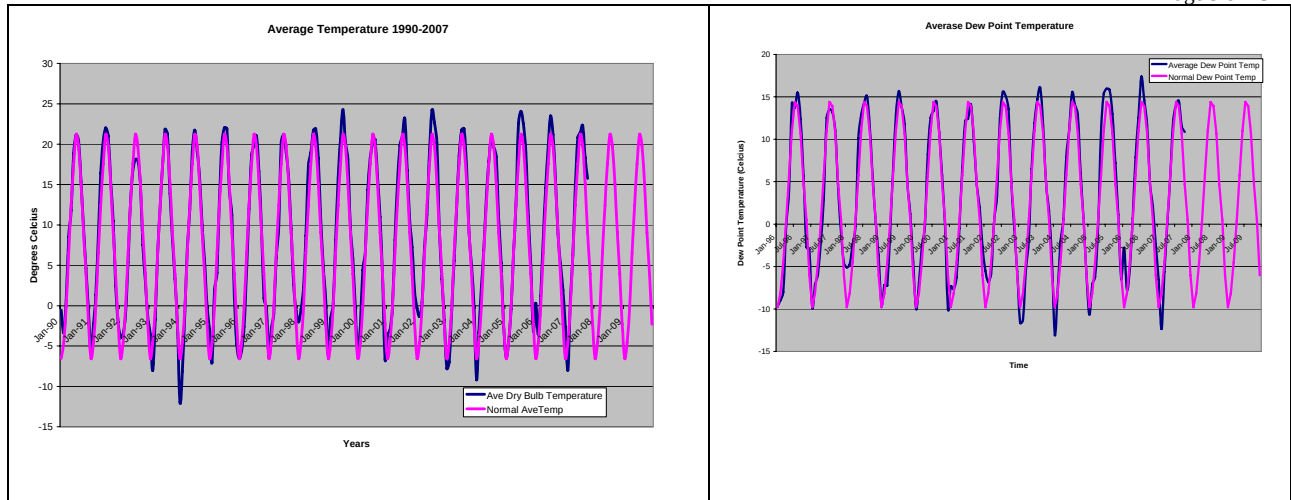
#8. Please provide data which demonstrates how the Enersource weather normalization methodology has performed over the years in which it has been in place.

Response

Enersource's short term load forecast requires normal weather scenario of temperature and dew point data. Temperature of the air is measured in degrees Celsius. Dew point temperature is a measure of the humidity of the air, and is also expressed in degrees Celsius. Since 1990, the average actual temperature was 8.58 Celsius and the normal weather temperature was 7.74 Celsius. The average actual dew point temperature was 3.18 and the normal weather dew point temperature was 2.73 Celsius.

Year	Ave Temp	Normal Ave Temp	Diff %
1990	8.86	7.74	13%
1991	9.03	7.74	14%
1992	7.23	7.74	-7%
1993	7.45	7.74	-4%
1994	7.46	7.74	-4%
1995	7.94	7.74	3%
1996	7.32	7.74	-6%
1997	7.77	7.74	0%
1998	10.26	7.74	25%
1999	9.58	7.74	19%
2000	8.37	7.74	8%
2001	9.7	7.74	20%
2002	9.52	7.74	19%
2003	8	7.74	3%
2004	8.36	7.74	7%
2005	9.13	7.74	15%
2006	9.85	7.74	21%
2007	8.55	7.74	9%
Average	8.58	7.74	10%

Year	Ave Dew Point	Normal Ave Dew Point	Diff (%)
1990	3.84	2.73	29%
1991	3.59	2.73	24%
1992	2.88	2.73	5%
1993	2.57	2.73	-6%
1994	2.42	2.73	-13%
1995	2.89	2.73	6%
1996	2.73	2.73	0%
1997	2.24	2.73	-22%
1998	4.44	2.73	39%
1999	3.08	2.73	11%
2000	2.92	2.73	7%
2001	3.11	2.73	12%
2002	3.46	2.73	21%
2003	2.75	2.73	1%
2004	3.29	2.73	17%
2005	4.03	2.73	32%
2006	4.44	2.73	39%
2007	2.65	2.73	-3%
Average	3.18	2.73	14%



Interrogatory

B/S3/T2

#9. With respect to the Short-Term Load Forecast please indicate how long Enersource has been using this methodology. Please provide data which demonstrates how the methodology has performed relative to actual results.

Response

Enersource has been utilizing this Load Forecasting methodology since 2004. From inception, the forecasts were found to be within 0.73% relative to actual results.

2004	Actual System Load	Original Forecast	% Diff		2005	Actual System Load	Forecasted (Nov 2004)	% Diff
Jan	714,721	693,184	3.01%		Jan	721,089	701,604	2.70%
Feb	653,440	647,166	0.96%		Feb	639,696	637,829	0.29%
Mar	671,003	665,011	0.89%		Mar	686,331	673,481	1.87%
April	617,225	614,215	0.49%		April	616,175	626,412	-1.66%
May	626,305	618,705	1.21%		May	628,104	636,357	-1.31%
June	647,295	649,179	-0.29%		June	748,571	660,600	11.75%
July	693,708	717,841	-3.48%		July	793,725	725,370	8.61%
Aug	689,063	688,030	0.15%		Aug	766,858	706,976	7.81%
Sept	661,766	629,170	4.93%		Sept	674,420	642,469	4.74%
Oct	632,873	634,224	-0.21%		Oct	644,954	645,802	-0.13%
Nov	645,704	658,130	-1.92%		Nov	649,772	669,728	-3.07%
Dec	690,680	683,370	1.06%		Dec	695,311	695,129	0.03%
Total 2004	7,943,783	7,898,226	0.57%		Total 2005	8,265,006	8,021,757	2.94%

2006	Actual System Load	Forecasted (Dec 2005)	% Diff		2007	Actual System Load	Forecasted (Aug 2006)	% Diff
Jan	691,202	727,864	-5.30%		Jan	710,722	739,010	-3.98%
Feb	640,334	653,568	-2.07%		Feb	669,216	661,762	1.11%
Mar	684,468	697,484	-1.90%		Mar	683,985	703,626	-2.87%
April	600,552	627,393	-4.47%		April	630,841	637,217	-1.01%
May	650,068	650,074	0.00%		May	653,094	659,165	-0.93%
June	696,319	675,351	3.01%		June	718,881	680,528	5.34%
July	784,045	733,847	6.40%		July	730,505	747,023	-2.26%
Aug	738,473	720,626	2.42%		Aug	769,492	730,082	5.12%
Sept	635,356	647,567	-1.92%		Sept	667,057	653,015	2.11%
Oct	643,460	658,296	-2.31%		Oct		671,725	
Nov	649,601	671,568	-3.38%		Nov		680,434	
Dec	671,816	711,464	-5.90%		Dec		717,789	
Total 2006	8,085,693	8,175,104	-1.11%		YTD 2007	6,233,794	6,211,428	0.36%

Interrogatory

C/S1/T1/p.1

#10. The evidence states that, “Enersource has relied on its traditional budgeting methodology and its long-standing business practices to identify the required capital spending that will occur during the 2008 test year. For the years 2000-2006 please provide Enersource’s capital budget and actual capital spending in the same format as Exhibit C/S3/T3.

Response

[Please see the attached table.](#)

Interrogatory

C/S2/T2.1/p.2

#11. Please provide a detailed explanation as to how Enersource developed the typical energy and demand per added customer. Please provide a schedule setting out forecast and actual energy and demand per customer for each class for the years 2000-2006.

Response

Enersource develops the typical energy and demand per added customer as follows:

- o Commercial / Industrial customers: Enersource uses 60% of the transformer's rated capacity as a proxy of the load; please note that the transformer's size is determined by device and usage pattern information provided by the customer, this information is collected and evaluated on a customer specific basis.
- o Residential customers/Small Commercial: Enersource uses the average consumption per customer of the prior period. The average consumption used in the analysis was reviewed in 2006 and better reflects actual consumption of Residential and Small Commercial Customers.

Estimate of average energy per added customer (monthly kWh)

<i>Customer Class</i>	<i>2001-2005</i>	<i>2006</i>
Residential	964	840
Small Commercial	491	479
General Service < 50kW	3,123	3,123

Enersource will review this data in 2008.

Interrogatory

C/S2/T2.1/p.3

#12. For the purposes of conducting the NPV calculation for expansions and connections Enersource uses the average OM&A of \$129.23/per customer/per year. What is the basis of that calculation?

Response

The \$129.23 is based on the incremental yearly average operating costs per customer. The actual calculation is based on historical operating cost data and is only factored into the economic evaluation of an expansion project.

Interrogatory

C/S2/T3/p.1

#13.The evidence states that the SPL CIS solution was the lowest cost proposal. Please provide evidence to support that statement. Please provide a detailed account of the process THESL and Enersource underwent prior to contracting with SPL. Of the \$7.914 million of Enersource's costs please explain how that allocation was determined.

Response

Please refer to answer to SEC interrogatory number # 28 for the:

- CIS Project Plan;
- CIS RFP Evaluation document;
- RFP Cost Comparison; and
- CIS Budget.

Please also refer to the response to SEC interrogatory #30.

Interrogatory

C/S2/T3/p.3

#14. The evidence states that, “A joint CIS implementation with Toronto Hydro provides several benefits to Enersource including lower costs and reduced implementation risk.” Please provide detailed evidence to support why this is the case relative to other alternatives that were considered by Enersource. How will the risk be shared between THESL and Enersource?

Response

Please refer to answer to SEC interrogatory number # 28 for the:

- CIS Project Plan;
- CIS RFP Evaluation document;
- RFP Cost Comparison; and
- CIS Budget.

Please also refer to the response to SEC interrogatory #30.

Interrogatory

D/S1/T1

#15. With respect to Distribution OM&A please indicate to what extent Enersource has included cost savings associated with the Smart meter initiative. Please specifically identify cost savings expected in 2008.

Response

In 2008, Enersource has not incorporated any cost savings associated with the Smart meter initiative. The Smart meter roll-out will occur over four years and the costs saving and rate impacts are unknown.

Interrogatory

D/S1/T6

#16. Please provide a detailed break-out of the \$270,000 forecast for legal and consulting regulatory costs. Please include all assumptions. For the past 5 years please provide actual legal and regulatory costs incurred.

Response

The requested break out is provided below:

Legal Services	\$175,000
Intervenor Costs	\$ 45,000
<u>Consultants</u>	<u>\$ 50,000</u>
Total	\$270,000

	2002	2003	2004	2005	2006
Legal and Regulatory costs	-	-	360,405	14,301	27,035

Enersource began tracking legal and consulting regulatory costs separately from 2004. Prior to that, these costs would have been included as part of total legal and other professional service costs for Enersource Hydro Mississauga. In 2002 and 2003 total legal and other professional service costs were \$84,000 and \$146,000 respectively.

Interrogatory

D/S1/T10/p.3

#17. Will Enersource agree to withdraw its request to gross up for taxes the SSM amount set out in its application, in light of the OEB's Decision to reject Toronto Hydro's request to do the same. If not, why not?

Response

Enersource will withdraw its request to gross up for taxes.

Interrogatory

D/S1/T10/p.3

#18. Will Enersource agree to withdraw its proposal to include free-riders in its LRAM calculation, in light of the OEB's Decision to reject Toronto Hydro's request to do the same? If not, why not?

Response

Enersource will withdraw its proposal to include free-riders in the Lost Revenue Adjustment Mechanism calculation.

Interrogatory

D/S1/T10/p.3

#19. With respect to Enersource's calculations of the SSM amount and the LRAM amount please indicate the extent to which they complied with the Board's TRC Guide. If values were used other than those set out in the TRC Guide please identify those values and provide an explanation as to why they were used.

Response

Enersource's claimed Shared Savings Mechanism award and claimed Lost Revenue Adjustment Mechanism claim rely on the Board's Total Resource Cost Guide. All Enersource's programs related to mass markets and are the subject of the Board's Total Resource Cost Guide. Enersource did not offer any custom programs and as a result has not relied on data from a source other than the Board's Total Resource Cost Guide.

Interrogatory

D/S2/T1

#20. Please provide the Board approved OM&A amounts for the year 2006 in the same format as Exhibit D/S2/T1 and D/S2/T2.

Response

[Please see the response to Board Staff interrogatory #30.](#)

Interrogatory

H/S2/T4

#21. The evidence states, “Enersource also proposes to recover and recognize the costs incurred to install Smart Meters during the 2008 Test Year”. With respect to SM costs:

- a. Please provide a schedule setting out how all SM costs are to be recovered in 2008 (rate adder, through rates etc.);
- b. Please indicate how Enersource plans to reconcile the SM costs recovered through the \$.57 rate adder and the actual costs incurred;
- c. Please provide a detailed explanation as to how the \$.57 rate adder was determined;
- d. Please confirm that all SM cost recovery is related to minimum functionality. If the costs are not related to minimum functionality please provide the required business cases to support expenditures beyond the minimum functionality.
- e. How does Enersource plan to recover costs related to the MDMR in 2008?
- f. Please indicate if Enersource plans to communicate with its customers regarding the SM implementation and if so, how the costs of such communication will be recovered in 2008;
- g. Does Enersource accept the principle that all actual smart meter costs (to the extent they are prudently incurred) should be recovered from ratepayers?
- h. Please provide a schedule setting out all SM costs incurred to date and all revenue recovered from customers related to Enersource’s SM plan. Please include the actual number of meters installed.
- i. Please provide a schedule setting out Enersource’s planned expenditures for SMs for the period 2008-2010.

Response

Please refer to Exhibit G/ Schedule 2/ Tab 6.

a. Enersource seeks to recover 2008 Smart Meter costs through a Smart Meter Rate Adder ("2008 SMRA") of \$0.57/metered-customer/month. This is detailed at Exhibit G/ Schedule 2/ Tab 6.

b. Please refer to Exhibit G/ Schedule 2/ Tab 6.

c. The detailed explanation of how the SMRA was determined can be found in Exhibit G/ Schedule 2/ Tab 6. The detailed derivation of the proposed 2008 SMRA of \$0.57 is provided at Exhibit G/ Schedule 2/ Tab 7.

d. See response to Board Staff interrogatory #56 b.

e. Enersource does not have any knowledge of the costs related to MDM/R and none are dealt with in this application. When these costs are known Enersource will propose an appropriate recovery mechanism.

f. Enersource has developed a communication program and the recovery of these operating costs is included in the proposed Smart Meter Rate Adder.

g. Yes

h.

Activity to September 30, 2007 (000's)	
Smart Meters Installed to Date	47,804
Smart Meter Costs incurred to Date	\$5,553
Operating Expenses	\$1,027
Disposal	\$1,339
Smart Meter Revenue	\$1,855

i. Enersource's planned capital expenditures are as follows:

Smart Meter Expenditures 2008-2010 (000's)		
2008	2009	2010
\$ 12,243	\$ 13,287	\$ 15,735

CCC Interrogatories

Index of Attachments

1. #1 CCC.pdf
2. #4 CCC.pdf
3. #7 CCC.pdf
4. #10i CCC.pdf

RATE BASE (000's)

Property, Plant & Equipment	EDR 2006	Test 2008	Bridge 2007	Actual 2006
<u>DISTRIBUTION ASSETS:</u>				
Land and Buildings	\$ 17,216	\$ 19,882	\$ 18,639	\$ 18,392
TS Primary Above 50	\$ -	\$ -	\$ -	\$ -
DS	\$ 59,279	\$ 67,941	\$ 65,898	\$ 63,673
Poles, Wires	\$ 488,408	\$ 593,896	\$ 565,674	\$ 539,021
Line Transformers	\$ 69,807	\$ 67,654	\$ 68,539	\$ 69,342
Services and Meters	\$ 31,196	\$ 36,762	\$ 34,731	\$ 32,976
General Plant	\$ -	\$ -	\$ -	\$ -
Equipment	\$ 17,041	\$ 27,269	\$ 23,233	\$ 20,511
IT Assets	\$ 9,300	\$ 13,208	\$ 8,442	\$ 6,726
CDM Assets	\$ 2,793	\$ -	\$ -	\$ -
Other Distribution Assets	\$ 14,401	\$ 14,852	\$ 14,112	\$ 14,488
Contributions and Grants	\$ (42,230)	\$ (53,858)	\$ (52,760)	\$ (51,926)
Construction Work In Progress	\$ -	\$ 5,182	\$ 9,182	\$ 8,464
TOTAL DISTRIBUTION ASSETS	\$ 667,211	\$ 792,787	\$ 755,691	\$ 721,665
<u>Total Distribution Assets (as above) - LESS:</u>				
Construction Work In Progress	\$ -	\$ (5,182)	\$ (9,182)	\$ (8,464)
Accumulated Amortization	\$ (278,088)	\$ (378,678)	\$ (350,221)	\$ (324,439)
NET FIXED DISTRIBUTION ASSETS	\$ 389,123	\$ 408,928	\$ 396,287	\$ 388,762
<u>Allowance for Working Capital</u>				
TOTAL COST OF POWER	539,291	601,101	564,470	557,590
Operation (Working Capital)	11,077	17,279	16,468	14,395
Maintenance (Working Capital)	2,048	2,557	2,530	2,630
Billing and Collection (Working Capital)	(151)	5,286	5,103	4,311
Community Relations (Working Capital)	0	0	0	0
Community Relations - CDM (Working Capital)	1,525	0	2,600	1,906
Administrative and General Expenses (Working Capital)	16,365	14,431	12,394	9,001
Insurance Expense (Working Capital)	800	0	0	0
Bad Debt Expense (Working Capital)	959	1,575	1,875	2,580
Advertising Expenses	0	0	0	0
Charitable Contributions	11	0	0	0
Other Distribution Expenses	0	949	918	639
TOTAL EXPENSES	32,633	42,076	41,889	35,461
Total for consideration of Working Cash Allowance	\$ 571,924	\$ 643,178	\$ 606,359	\$ 593,051
Working Cash Allowance (15% COP & Expenses)	\$ 85,789	\$ 96,477	\$ 90,954	\$ 88,958
RATE BASE	\$ 474,912	\$ 505,404	\$ 487,241	\$ 477,720

CCC#10
Enersource Hydro Mississauga
2000-2006 Capital Budget and Actual Capital Spending

	2000 Capital Budget	2000 Actual Spent	2001 Capital Budget	2001 Actual Spent	2002 Capital Budget	2002 Actual Spent	2003 Capital Budget	2003 Actual Spent
LAND	-	-	-	-	-	-	-	-
SUBSTATION EQUIPMENT	5,550,000	9,939,655	4,950,000	4,703,306	3,750,000	2,063,132	2,400,000	2,514,089
SUPERVISORY CONTROL EQUIPT.	2,000,000	5,017,527	1,900,000	696,662	1,800,000	202,646	1,500,000	1,324,726
O/H PRIMARY	7,395,000	13,933,976	8,005,000	7,390,489	8,110,000	6,806,122	7,600,000	6,784,671
U/G PRIMARY	9,350,000	17,778,193	9,700,000	10,213,140	13,100,000	10,053,784	11,300,000	10,911,517
METERS	1,300,000	2,061,811	1,135,000	993,334	1,000,000	943,594	1,000,000	746,843
GENERAL OFFICE EQUIPMENT	460,000	724,746	560,000	443,793	750,000	727,301	566,500	259,871
ROLLING STOCK & EQUIPMENT	1,771,000	476,395	1,600,000	800,415	900,000	962,303	935,000	78,865
MAJOR TOOLS & INSTR.	100,000	176,479	150,000	134,206	150,000	145,967	175,000	109,146
COMPUTER EQUIPMENT	360,000	537,300	390,000	386,294	645,000	538,335	1,750,000	1,388,798
SOFTWARE	1,208,000	2,624,386	1,446,000	7,173,357	3,433,000	6,048,285	1,596,000	1,893,312
WATER HEATERS	382,000	172,923	326,000	295,623				
OTHER	1,000,000		2,400,000		1,500,000			
	30,876,000	53,443,391	32,562,000	33,230,619	35,138,000	28,491,469	28,822,500	26,011,838

	2004 Capital Budget	2004 Actual Spent	2005 Capital Budget	2005 Actual Spent	2006 Capital Budget	2006 Actual Spent
LAND	-	-	-	-	-	-
SUBSTATION EQUIPMENT	2,400,000	2,732,276	2,400,000	2,842,996	2,875,000	3,311,437
SUPERVISORY CONTROL EQUIPT.	1,400,000	775,147	1,500,000	1,193,162	1,120,000	1,550,572
O/H PRIMARY	7,100,000	7,939,822	8,100,000	8,367,564	8,925,000	8,299,060
U/G PRIMARY	12,050,000	11,690,677	12,550,000	12,547,720	13,475,000	14,393,069
METERS	1,000,000	1,238,404	1,000,000	1,248,761	1,350,086	1,254,816
GENERAL OFFICE EQUIPMENT	1,145,000	1,060,512	1,380,000	1,604,167	1,113,500	989,770
ROLLING STOCK & EQUIPMENT	1,580,000	2,356,769	1,766,000	1,817,907	1,725,000	1,622,595
MAJOR TOOLS & INSTR.	150,000	145,330	150,000	201,986	150,000	142,507
COMPUTER EQUIPMENT	1,740,000	659,322	1,975,000	480,870	2,650,000	2,035,154
SOFTWARE	1,208,500	1,315,609	897,000	1,008,038	4,704,000	1,044,313
TOTAL	29,773,500	29,913,868	31,718,000	31,313,171	38,087,586	34,643,293

CONSERVATION & DEMAND MANAGEMENT (Funded through 3rd Tranche)	-	-	-	1,146,661	4,358,000	1,874,097

CCC #4.

RATE CLASS	Average Number of Customers (Connections)							
	2004	2005	2005	2006	2006	2007	2007	2008
	Actual	Actual	% Inc	Actual	% Inc	Forecast	% Inc	Forecast
Residential	154,721	157,564	1.8%	159,692	1.4%	161,217	1.0%	163,670
Less than 50 kW	15,848	15,705	-0.9%	15,764	0.4%	15,946	1.2%	16,081
Small Commercial	3,158	3,370	6.7%	3,245	-3.7%	3,265	0.6%	3,288
GS 50-499 kW	3,903	3,995	2.4%	3,920	-1.9%	3,960	1.0%	3,986
GS 500-4999 kW	409	435	6.4%	461	6.0%	466	1.1%	470
Large User	9	8	-11.1%	9	12.5%	9	0.0%	9
Street Lighting	47,027	47,514	1.0%	47,588	0.2%	47,981	0.8%	48,255
TOTALS	225,075	228,591	1.6%	230,679	0.9%	232,844	0.9%	235,759

Enersource Hydro Mississauga Inc.

ED-2003-0017 (RP-2005-0020, EB-2005-0360)

November 30, 2005. (Revision #1)

5-2 SPECIFIC SERVICE CHARGES (Input)

[to Overview](#)

Rate Code	Description	Standard Amount (Rate) \$	Applicable?	Updated Amt. (if applic.) \$	2002 Volume	2003 Volume	2004 Volume	Test Year Volume (3 yr. avg.)	Calc'd. Amt. - Std. Formula \$	Alternate Amount (if applic.) \$	Calc. Method (attach. calc. & justification)	Amount for Rate Calculations \$
1	Arrears certificate	15.00	Y	15.00	402	360	441	401	6,015.00		Standard	6,015.00
2	Statement of account	15.00	N					0	0.00		Standard	0.00
3	Pulling post dated cheques	15.00	N					0	0.00		Standard	0.00
4	Duplicate invoices for previous billing	15.00	N					0	0.00		Standard	0.00
5	Request for other billing information	15.00	Y	15.00			1,176	1,176	17,640.00		Standard	17,640.00
6	Easement letter	15.00	N					0	0.00		Standard	0.00
7	Income tax letter	15.00	Y	15.00	65	46	88	66	995.00		Standard	995.00
8	Notification charge	15.00	N					0	0.00		Standard	0.00
9	Account history	15.00	N					0	0.00		Standard	0.00
10	Credit reference/credit check (plus credit agency costs)	15.00	Y	15.00			3,515	3,515	52,725.00		Standard	52,725.00
11	Returned cheque charge (plus bank charges)	15.00	Y	12.50	4,496	4,141	2,906	3,848	48,095.83		Standard	48,095.83
12	Charge to certify cheque	15.00	N					0	0.00		Standard	0.00
13	Legal letter charge	15.00	N					0	0.00		Standard	0.00
14	Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	30.00	Y	30.00	2,316	2,888	3,407	2,870	86,110.00		Standard	86,110.00
15	Special meter reads	30.00	Y	30.00				0	0.00		Standard	0.00
16	Collection of account charge - no disconnection	30.00	Y	9.00	18,271	16,196	16,829	17,099	153,888.00		Standard	153,888.00
17	Collection of account charge - no disconnection - after regular hours	165.00	N					0	0.00		Standard	0.00
18	Disconnect/Reconnect at meter - during regular hours	65.00	Y	20.00	827	1,055	360	747	14,946.67		Standard	14,946.67
19	Install/Remove load control device - during regular hours	65.00	N					0	0.00		Standard	0.00
20	Disconnect/Reconnect at meter - after regular hours	185.00	N					0	0.00		Standard	0.00
21	Install/Remove load control device - after regular hours	185.00	N					0	0.00		Standard	0.00
22	Disconnect/Reconnect at pole - during regular hours	185.00	Y	185.00	20	20	20	20	3,700.00		Standard	3,700.00
23	Disconnect/Reconnect at pole - after regular hours	415.00	Y	415.00	5	5	5	5	2,075.00		Standard	2,075.00
24	Meter dispute charge plus Measurement Canada fees (if meter found correct)	30.00	Y	10.00	18	12	14	15	146.67		Standard	146.67
25	Service call - customer-owned equipment	30.00	N					0	0.00		Standard	0.00
26	Service call - after regular hours	165.00	N					0	0.00		Standard	0.00
27	Temporary service install & remove - overhead - no transformer	500.00	Y	400.00	144	141	136	140	56,133.33		Standard	56,133.33
28	Temporary service install & remove - underground - no transformer	300.00	N					0	0.00		Standard	0.00
29	Temporary service install & remove - overhead - with transformer	1,000.00	N					0	0.00		Standard	0.00
30	Specific Charge for Access to the Power Poles \$/pole/year	22.35	Y		12,489	12,443	12,709	12,547	280,425.45		Standard	280,425.45
Additional Charges - Please be Specific												
31	First Additional Charge	N/A	N					0	0.00		addnl. chrg	0.00
32	Second Additional Charge	N/A	N					0	0.00		addnl. chrg	0.00
33	Account set up charge/change of occupancy charge (plus credit agency costs if applicable) - Residential	N/A	Y	20.00	16,500	23,373	19,655	19,843	396,853.33		addnl. chrg	396,853.33
34	Interval Meter Request Charge	N/A	Y	40.00	7	3	1	4	146.67		addnl. chrg	146.67
35	Credit reference/credit check (plus credit agency costs) - Gen. Service - See section 2.4.11 b of DSC	N/A	Y	25.00			39	39	975.00		addnl. chrg	975.00
36	Standby Charges	N/A	Y	200.00			12	12	2,400.00		addnl. chrg	2,400.00
Total Specific Service Charge Revenue									1,123,270.95			1,123,270.95

Energy Probe Interrogatories

Interrogatory

1. Ref: Exhibit A/Schedule 11/Tab 1.1

Background:

In the RP-2005-0020/EB-2005-0360 Decision With Reasons, in respect of the Applicant's 2006 Rates Case, the Board examined unfilled vacancies at Page 5, Tier 1 adjustment – Unfilled Vacancies. In that proceeding Enersource requested \$1,131,601 be included in distribution rates in order to reflect the existence of 23 vacant positions that were over the normal number of vacant positions of 15. The Board did not approve the Applicant's request for \$1,131,601.

The evidence in this proceeding describes 48 vacancies listed under the Enersource Corporation Organization Chart, 43 of which relate to the Applicant, the other 5 relating to Enersource Corporation.

Questions:

- a) What is the normal number of vacant positions for Enersource Hydro Mississauga for 2006 and 2007 that is comparable to the normal number of vacant positions of 15 for 2004 quoted in the Board's Decision With Reasons in RP-2005-0020/EB-2005-0360?**
- b) Please provide the ratio of vacant to active positions for Enersource Hydro Mississauga in the 2004 headcount in the RP-2005-0020/EB-2005-0360 proceeding, and the same statistic for 2006 and 2007.**

Response

Please note that Enersource's proposed Tier 1 adjustment for unfilled vacancies was subsequently approved by the Board (EB-2006-0109).

- a) Enersource family of companies' normal vacancy rate for 2006 and 2007 is 20 positions for an average of 10 weeks per year. Enersource Hydro Mississauga proportionate share of vacancies is 17.

b)

	2004/2006 EDR	2006	2007
Vacant	29	13	17
Active	264	287	306
Total	293	300	323
	11%	5%	6%

Interrogatory

2. Ref: Exhibit A/Schedule 11/Tab 1.1

Background:

The evidence in this Schedule consists of a chart, the Enersource Corporation Organization Chart, which portrays a headcount of 47 listed under the Enersource Corporation, 5 of which are vacant, all of which appear to be involved in duties supporting functions of the Applicant. In the chart a headcount of 8 relates to the Executive function.

Questions:

- a) Please identify the management functions at the level of vice president and above which are outsourced from Enersource Hydro to the Enersource Corporation.**
- b) Please identify the president and the CEO of Enersource Hydro, and indicate whether they are employees of the Applicant or if the functions are outsourced.**
- c) Please advise the economies, if any, achieved by this arrangement for residential customers of Enersource Hydro.**

Response

a. The President and CEO, General Counsel, CFO, Vice President Human Resources, Vice President Safety are employees of Enersource Corporation.

b. The President and CEO of Enersource Hydro is Craig Fleming, who is an employee of Enersource Corporation. Enersource Hydro's organization chart is provided at Exhibit A/ Schedule 11/ Tab 1; it indicates that the most senior position within Enersource Hydro is the Executive Vice President and Chief Operating Officer.

c) Enersource Corporation provides Enersource Hydro with Executive management services, including Human Resources, Finance, Legal and Chief Executive Officer Services. Enersource Hydro pays a Management Fee to Enersource Corporation that represents a portion of the costs for these services. Because Enersource Hydro pays a portion of the costs incurred, rather than the full cost, all customers including residential customers pay rates that are lower than they would be on a full cost basis or if each company had its own set of executive employees.

Interrogatory

3. Ref: Exhibit A/Schedule 11/Tab 1.1

Background:

The evidence in this Schedule consists of a chart, the Enersource Corporation Organization Chart, which portrays a headcount of 14 listed under the Enersource Corporation, 1 of which is vacant, all of which appear to be involved in duties supporting functions of the Applicant in respect of Human Resources, Administration, Communications and Legal Counsel.

Questions:

- a) Please confirm that no personnel of the Applicant are involved duties supporting functions of the Applicant in respect of Human Resources, Administration, Communications and Legal Counsel.**
- b) Please advise the economies, if any, achieved by this arrangement for residential customers of Enersource Hydro.**

Response

a) Enersource Hydro confirms that it does not employ any staff involved in the provision of Human Resources, Communications or Legal Counsel Services, or the Administrative Support associated with the provision of these services. All administrative support and services related solely to Enersource Hydro are provided within Enersource Hydro.

b) Enersource Corporation provides Enersource Hydro with Executive management services, including Human Resources, Finance, Legal and Chief Executive Officer Services. Enersource Hydro pays a Management Fee to Enersource Corporation that represents a portion of these costs for these services. Because Enersource Hydro pays a portion of the costs incurred, rather than the full cost, all customers including residential customers pay rates that are lower than they would be on a full cost basis or if each company had its own set of executive employees.

Interrogatory

4. Ref: Exhibit A/Schedule 11/Tab 1.1

Background:

The evidence in this Schedule consists of a chart, the Enersource Corporation Organization Chart, which portrays a headcount of 29 listed under the Enersource Corporation, 4 of which are vacant, all of which appear to be involved in duties supporting functions of the Applicant in respect of Finance.

Questions:

- a) Please confirm that no personnel of the Applicant are involved duties supporting functions of the Applicant in respect of Finance.**
- b) Please advise the economies, if any, achieved by this arrangement for residential customers of Enersource Hydro.**
- c) Has Enersource Hydro ever had an internal Finance department?**

Response

- a) Enersource Hydro confirms that it does not employ any staff involved in the provision of Finance and related services.
- b) Enersource Corporation provides Enersource Hydro with Finance and related services. Enersource Hydro pays a Management Fee to Enersource Corporation that represents a portion of these costs for these services. Because Enersource Hydro pays a portion of the costs incurred, rather than the full cost, all customers including residential customers pay rates that are lower than they would be on a full cost basis.
- c) Enersource Corporation was incorporated in 2000. Enersource Hydro was incorporated in 2001. The Finance Department was transferred from Hydro Mississauga to Enersource Corporation in 2001.

Interrogatory

5. Ref: Exhibit A/Schedule 11/Tab 1.1

Background:

The evidence in this Schedule consists of a chart, the Enersource Corporation Organization Chart, which portrays a headcount of 47 listed under Enersource Hydro, 7 of which are vacant, all of which appear to be involved in duties supporting functions of the Applicant in respect of Information Services.

Questions:

- a) Please confirm that no personnel of the Enersource Corporation are involved duties supporting functions of the Applicant in respect of Information Services.**
- b) Do Enersource Corporation personnel supporting functions of the Applicant in respect of Finance use hardware, software and expertise of the Applicant's Information Services function in order to perform their duties?**
- c) Are these Enersource Corporation personnel entirely devoted to the Applicant's Finance function, or are they also performing duties in respect of the Finance function of the Enersource Corporation?**

Response

a) Enersource Hydro confirms that no personnel employed by Enersource Corporation are involved in duties or functions of Enersource Hydro related to the provision of Information Services.

b) Enersource Hydro provides Information Services to Enersource Corporation and it, in turn, relies on these services to be able to provide Finance related services to Enersource Hydro. Enersource Hydro allocates Information Services support costs based on headcount to all of its affiliates.

c) Enersource Corporation's Finance staff provides services to Enersource Corporation and all its affiliates.

Interrogatory

6. Ref: Exhibit A/Schedule 14/Tab 1

Background:

The evidence in the form of a Services Agreement between Enersource Hydro Mississauga Inc. and Enersource Corporation provides at Article 3.2 Performance Standards.

Questions:

- a) Please advise the penalties, other than right of termination by Enersource Hydro Mississauga Inc., that could be assessed against Enersource Corporation for failure to perform in the top quartile of industry standards as described.**
- b) Have any complains been filed by Enersource Hydro Mississauga Inc. in respect of a failure to perform?**
- c) In respect of Article 3.4, please advise the penalties, other than right of termination by Enersource Hydro Mississauga Inc., that could be assessed against Enersource Corporation for failure to comply with the listed covenants.**
- d) Please provide the last time that Enersource Hydro Mississauga Inc. compared or assessed the economic benefits of having the services described in the Services Agreement performed within the regulated utility versus outsourcing these services to Enersource Corporation. Please provide the results of this assessment and provide any report containing the assessments.**

Response

- a) Article 9 of the Services Agreement between Enersource Hydro and its affiliate's states:
"The remedies in this section are expressly in lieu of any or all of the remedies, which may be available to each of the Non-Regulated Affiliates and WIRESCO in respect of or under this Agreement resulting from the furnishing, the failure to furnish or the quality of any Services."
- b) Enersource Hydro has not filed any complaints against an affiliate related to a failure to perform.
- c) Please see the response provided to part a).

d) These services are core corporate services and would be shared service and would have the same cost regardless of whether they were provided by Enersource Corporation or Enersource Hydro. The costs of these services are predominately labour costs. The Human Resources group within Enersource Corporation monitors the labour market in the Greater Toronto Area to ensure that the Enersource family of companies is able to attract and retain an appropriately skilled and experienced work force and that its compensation package is competitive. Enersource Hydro also believes that due to the specialized nature of the industry, confidentiality, complexity and scale of its operations outsourcing any of the specialized functions will not provide any economic benefits.

Interrogatory

7. Ref: Exhibit D/Schedule 1/Tab 5

Background:

The evidence describes the Bad Debt experience of the Applicant and its efforts to improve its collections process.

Questions:

- a) Does the Applicant track Bad Debt experience due to “grow op” activities within its franchise area?**
- b) If it does track those losses, has there been an upward trend over the last 3 years?**

Response

a. Any “grow op” related activities in Enersource’s service area constitute theft of power. As such, the undetected electricity consumption of “grow ops” acts to increase distribution system losses. Any detected “grow op” consumption of power is billed to the account holder for that premise. Any consumption billed but not paid by the premise holder is incorporated in Enersource’s normal bad debt expense.

b. Enersource’s distribution losses for 2002 – 2006 range from 3.31%-4.54% and are provided at Exhibit D/ Schedule 2/ Tab 9.

EB-2007-0706

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

**AND IN THE MATTER OF an Application by Enersource
Hydro Mississauga Inc. for an Order or Orders
approving or fixing just and reasonable rates and other
charges for the distribution of electricity commencing
May 1, 2008.**

**INTERROGATORIES
OF THE
SCHOOL ENERGY COALITION**

School Energy Coalition Interrogatories

Interrogatory

#1. [Ref: A/8/2, p.5] Please estimate the additional annual volumes (energy or demand, depending on the rate class affected) and revenues that will be experienced by the Applicant in each of years 2008, 2009 and 2010 as a result of:

- a. The industrial development in the North 27.6 system;**
- b. The new water and waste water treatment plant; and**
- c. The additional residential loads in the western and central portions of the city.**

Response

Enersource's estimate of the additional annual volumes and revenues attributable to the three identified loads is included in its load forecast. Enersource does not estimate incremental customer specific loads and associated revenues but, rather estimates customer class loads that reflect the net effect of all underlying factors (eg., new customer growth, the effect of government programs, price elasticity responses).

- a. Based on Enersource's review of developer's site plans the following load increases are forecasted:

2008	10 MWs
2009	8 MWs
2010	5 MWs

- b. Region of Peel is expanding their existing water and wastewater plants in the south area of the city. Also the Lorne Park Pumping Station will be upgraded next year and the Clarkson Waste Water Treatment Plant is planned to be upgraded the year after. This development is all driven by the Region of Peel in order to meet demands from new customers. Based on available information, Enersource forecasts the following load increases:

2008	12 MWs
2009	8 MWs
2010	5 MWs

- c. Existing commercial buildings upgrades in the Meadowvale area, as well as, new industrial / commercial projects are also planned for this area (eg. refrigeration building, data centre). Enersource forecasts the following load increases:

2008	15 MWs

2009 10 MWs
2010 5 MWs

Interrogatory

#2. [Ref: A/8/5] Please file the load transfer plan referred to, if currently available.

Response

Enersource will develop the requested plan shortly and will file it with the Board on or before December 31, 2007, per the Distribution System Code. At this time, Enersource plans to connect those customers situated in its Service Area who are presently served by another distributor to Enersource's distribution system. Enersource is not able to speak to the plans of neighbouring distributors for the customers within their respective service areas that are provided with distribution service from Enersource's distribution system.

Interrogatory

#3. [Ref: A/11/1, Attach.] Please file a headcount chart in the form set out on page 51 for actuals as of July 2006, and forecast as of July 2008.

Response

[Please refer to the attached spreadsheets.](#)

Interrogatory

#4. [Ref: A/12/2] Please file the most recent audited financial statements and Annual Report for Enersource Corporation.

Response

Enersource Corporation's audited financial statements is available at <http://www.sedar.com/>.
Enersource Corporation's annual report is available at www.enersource.com.

Interrogatory

#5. [Ref: A/12/2] Please file the most recent Strategic Plan or similar document of the Applicant, and any part of the most recent Strategic Plan of Enersource Corporation that refers to the utility operations or finances.

Response

[Please see the attached document.](#)

Interrogatory

#6. [Ref: A/12/2] The Statement on Auditing Standards requires auditors to communicate reportable conditions to the audit committee. A reportable condition is a significant deficiency in the design or function of internal control that could adversely affect the organization's ability to record, process, summarize, and report financial data.

- a. Please advise whether Enersource's Audit Committee is aware of any reportable conditions.
- b. Please advise whether any reportable conditions have ever been noted by Enersource's external auditor during the past 3 years.
- c. If yes, please provide a copy of each communication by the Applicant's auditors of "Internal Control related matters noted in an audit" issued to the Audit Committee.

Response

- a. None were noted.
- b. None were noted.
- c. Not applicable.

Interrogatory

#7. [Ref: A/12/2, p. 18]. Please provide a copy of the actuarial valuation of the benefits liabilities done on March 2, 2007.

Response

[Please see the response to Board Staff interrogatory 28.](#)

Interrogatory

#8. [Ref: A/12/2, p. 24]. Please provide a copy of the agreement with Enerpower for the \$7.6 million of construction work. Please provide a breakdown of the work done, and the accounting and ratemaking treatment for all amounts. Please advise the location of Enerpower within the corporate structure chart on page 49 of the Applicant's evidence.

Response

Enerpower Corporation is 10% owned by Enersource Corporation and is not an affiliate. Enersource Corporation has entered into a Shareholder Agreement relating to this ownership, but this Agreement does not contain any operational commitments or exclusivity arrangements that are in effect.

Enerpower provides offer to connect work for customers and underground system rebuild services for Enersource Hydro. All work performed by Enerpower is governed through purchase orders with Enersource's standard terms and conditions. Competitive quotations are obtained.

The costs relating to offer to connect services provided are capitalized based upon a capital contribution formula. This methodology is applied to all new customer capital amounts, regardless of the company providing the service. All rebuild work provided by Enerpower is fully capitalized.

Interrogatory

#9. [Ref: A/12/5, Attach1, p.2] Please reconcile the annual capital spending estimate of \$50 million including \$9 million for smart meters, covering the consolidated corporate group, with the capital spending of about \$45 million plus smart meters in the Application.

Response

The capital spending referenced at Exhibit A/ Schedule 12/ Tab5 was based on the 2007 budget for Enersource Corporation and all of its affiliates. The amount included in the Application is the 2007 forecast and 2008 budget for Enersource Hydro only.

Interrogatory

#10. [Ref: A/12/5, Attach 1, p.6] Please advise whether the \$290 million of bonds held by Borealis Infrastructure Trust are subject to any early repayment (either voluntary or mandatory) provisions and, if so, provide a summary of those provisions including any penalties associated with them.

Response

The \$290 million of bonds held by Borealis Infrastructure Trust do have an optional prepayment provision. This provision provides for a formulaic prepayment of all interest and principal discounted at an appropriate rate.

Interrogatory

#11. [Ref: A/12/5, Attach 1, p.8] Please explain why OM&A/avg.customer jumped 8.1% in 2006. Please provide calculations of OM&A/avg. customer for each of 2007 (forecast) and 2008 (budget applied for) calculated on a comparable basis.

Response

Enersource notes that these calculations were made by the Dominion Bond Rating Service.

Interrogatory

#12. [Ref: A/12/5] Please provide the transcript and audio tape of any investor conference call or similar investor relations communication by the Applicant or its parent company during 2007.

Response

Enersource Hydro does not keep transcripts and audio tapes of any investor conference call or similar investor relations communication. There are no transcripts or audio tapes of investor conference calls or similar investor relations communication by the Applicant or its parent company during 2007.

Interrogatory

#13. [Ref: A/12/5, Attach. 2, p.2] Please provide the source, if known, of the rating agency's statement "Enersource's residential and commercial distribution rates are among the lowest in the province". Please provide evidence that this statement is correct.

Response

Enersource is unable to provide the requested information as the source of the information that forms the basis of the statement is unknown.

Interrogatory

#14. [Ref: A/12/5, Attach.2, p3] Please provide any information in the possession of the Applicant or its parent company with respect to any increase in interest rate on the 6.29% bonds at the time of issuance as a result of the fact that “Enersource’s higher risk and competitive-based unregulated businesses modestly weaken an otherwise excellent business risk profile”.

Response

At the time of the bond issue, Enersource Corporation’s unregulated businesses did not have a material impact on its financial profile. As such, there would have been no significant impact on the bond rate resulting from any unregulated operations.

Interrogatory

#15. [Ref: A/13/1, p.1] Please provide any memoranda, policy statements, operating manuals, or other documents that included instructions to business units or their personnel on how to prepare the 2007 Bridge Year or the 2008 Test Year budget.

Response

The budget process described in the evidence reference is accurate. There are no memoranda, policy statements, operating manuals or instructions on business unit budgeting. Each business unit was reviewed by Finance, the manager responsible and divisional lead.

Interrogatory

#16. [Ref: A/14/1] On page 1 of A/S14/T1, it was stated that the non-regulated affiliates are charged a cost based rate for the use of Enersource Hydro Mississauga Inc. (EHM) assets (trucks and other vehicles). In Sch B of the Service Agreement (page 128 of Pre-filed Evidence), Other Services Fees for services provided by EHM to its non-regulated affiliates “shall be calculated and charged on a cost basis”. Section 5.1 of the Service Agreement (page 118 of pre-filed Evidence), “the non-regulated affiliates shall pay to WIRESCO (EHM) the fees and charges set out in Schedule B which fees and charges have, where applicable, been calculated so as to allow WIRESCO a rate of return that is the higher of the bank prime rate and the regulated rate of return set for WIRESCO by the OEB”. In Sch B of the Amended Service Agreement (page 156 of pre-filed Evidence), Facilities and Property Usage fees “shall be calculated on a cost plus mark-up basis.” In light of this, please advise:

- a. For services provided by EHM to its non-regulated affiliates, are the non-regulated affiliates charged on a rate that is entirely cost based or a rate that includes a return? If EHM’s fees do include a mark-up or return, what is the amount and how is it calculated? Please provide any source documents detailing how the amount, percentage, or formula for any markup or return was initially established.
- b. Please provide a summary of amounts charged by EHM to its non-regulated affiliates for 2005-2008 by service category, separating cost and mark-up, with actuals for 2005 and 2006, forecast for 2007, and budget for 2008.

Response

- a. Please see the response to VECC interrogatory #9.
- b. Please refer to attached spreadsheet.

Interrogatory

#17. [Ref: A/15/1, H/3/1, and G/2/5, p.1] With respect to the existing and proposed rates for schools in the Applicant's franchise area:

- a. Please advise the number of schools that are customers of the Applicant, divided between those in Rate Class GS<50 and those in Rate Class GS>50, as well as those in other classes, if any.
- b. Please confirm that, given the assumptions in the first two lines below, the calculations in the following table are correct:

	Small School (GS<50)	Large School (GS>50)
Assumed average monthly consumption (kwhr)	16,000	
Assumed average monthly demand (KW)		380
2007 Distribution Cost-Fixed	\$359.16	\$890.88
2007 Distribution Cost –Volumetric (excl. Reg. Assets)	\$2,860.80	\$20,018.40
2007 Distribution Cost –Fixed plus Volumetric	\$3,219.96	\$20,909.28
2008 Distribution Cost-Fixed	\$388.92	\$990.48
2008 Distribution Cost –Volumetric (excl. Reg. Assets)	\$3,244.80	\$22,645.87
2008 Distribution Cost –Fixed plus Volumetric	\$3,633.72	\$23,636.35
Dollar Increase	\$413.76	\$2,727.07
Percentage Increase	12.85%	13.04%
2008 Distribution Cost at 100% Cost Allocation Factor per CAR-IF	\$3,198.70	\$18,777.67
Excess of proposed rates over 1:1 allocation	\$435.02	\$4,858.68

Response

- a. Enersource maintains customer class information based on consumption rather than the nature of the customer, consistent with the Board's class-based approach to rate-making.
- b. Enersource has not been able to replicate the data provided in the original table.

Interrogatory

#18. [Ref: B/2/1, B/2/2 and B/2/3] Please extend the tables on pages 378, 380, and 384 of the Application to include the years 2002 through 2005 inclusive.

Response

Please see the response to Board staff interrogatory #16.

Interrogatory

#19. [Ref: B/2/4] Please explain why the rates used are different from the approved rates set forth in A/15/1. If the latter rates are correct, please file a corrected version of B/2/4.

Response

The rates provided at ExhibitA/Schedule15/Tab1 include the Board authorized 2007 Smart Meter Rate Adder and the rates relied on at ExhibitB/Schedule2/Tab4 do not.

Interrogatory

#20. [Ref: B/2/5] EHM has indicated that it has recently introduced new payment mechanisms and may experience a reduction in revenues from Late Payment Charges in 2008 test year.

- a. Please describe in detail the newly introduced payment mechanisms.
- b. Please advise whether the bad debt expense and customer collection costs for 2008 test year and beyond will be reduced as a result of the introduction of the new payment mechanisms. Please identify the amount of any such reductions, and show where they have been taken into account in the calculation of the revenue requirement.
- c. Please identify and quantify any changes to the working capital calculations resulting from these new payment mechanisms.

Response

- a. To compliment our existing e-billing and pre-authorized debit programs, we are investigating the payment option of allowing customers to make payments via the Web, over the phone, or through a Customer Service Representative using Visa or MasterCard. This payment option will provide CSR assisted emergency payments, web-based one-time consumer payments and real-time account validation.
- b. The introduction of these new payment mechanisms have been deferred to late 2008. Bad debts and customer collection costs have not been reduced given the uncertainty in measuring the impact of introducing these new payment mechanisms and the timing of when the introduction would occur.
- c. No changes have been made or are anticipated from these new payment mechanisms.

Interrogatory

#21. [Ref: B/3/2] Please provide Tables 1 and 3 of this exhibit on a weather normalized basis.

Response

[Please see the response to Board staff interrogatory #21.](#)

Interrogatory

#22. [Ref: B/3/3] With respect to the load forecast:

- a. Please confirm that the effect of the actuals and forecasts of annual peak demand on pages 423 and 421 respectively of the Application produce the following chart:

Year	Annual Peak Demand	% Inc(- Dec.)
2000	1226	
2001	1358	10.77%
2002	1509	11.12%
2003	1505	-0.27%
2004	1427	-5.18%
2005	1570	10.02%
2006	1610	2.55%
2007	1512	-6.09%
2008	1531	1.26%
2009	1549	1.18%
2010	1567	1.16%
2011	1582	0.96%

- b. Please extend Figure 8 on page 14 of this Exhibit to cover the period 1982-2031, ie. the previous 25 years as well as the forecast 25 years already included.
- c. Please provide 2007 year to date actual figures corresponding with the forecasts in Table 14.

Response

- a. Please see the table below. Corrections have been made to the normal peaks for 2000 and 2001. Please note that Normal Weather Peak Demand Forecast is one component and that an extreme weather forecast completes the table.

Year	Annual Peak Demand + Normal Weather Forecast	% Inc.(- dec.)	Annual Peak Demand + Extreme Weather Forecast	% Inc.(- dec.)
1999*	1344		1344	

2000*	1305	-2.90%		1305	-2.90%
2001*	1477	13.18%		1477	13.18%
2002*	1509	2.17%		1509	2.17%
2003*	1505	-0.27%		1505	-0.27%
2004*	1427	-5.18%		1427	-5.18%
2005*	1570	10.02%		1570	10.02%
2006*	1610	2.55%		1610	2.55%
2007	1512	-6.09%		1635	1.55%
2008	1531	1.26%		1666	1.90%
2009	1549	1.18%		1685	1.14%
2010	1567	1.16%		1703	1.07%
2011	1582	0.96%		1717	0.82%

* Denotes actual annual peak demand.

Please note that this is only an observation that was included in [Ref: Exhibit B/ Schedule 3/ Tab 3]. For forecasting purposes two scenarios are utilized:

- Normal Weather Scenario; and
- Extreme Weather Scenario.

b. The data set relied on is provided by the City of Mississauga and does not extend to 2031. Please see the data below.

Year	Population
1991	482,700
1992	499,600
1993	516,500
1994	533,300
1995	550,200
1996	563,785
1997	582,164
1998	599,809
1999	616,587
2000	632,384
2001	647,105
2002	660,677
2003	673,047
2004	684,182
2005	694,068
2006	702,714
2007	710,146
2008	716,414
2009	721,584
2010	725,746
2011	729,008

2012	731,499
2013	733,368
2014	734,785
2015	736,198

c. Please see 2007 YTD figures below.

Monthly Peak Demand - Normal Weather

Month	Actual Peak Demand	Forecast (Normal Weather) Peak Demand	% Diff
Jan	1,217	1,402	-15%
Feb	1,235	1,390	-13%
Mar	1,160	1,340	-16%
Apr	1,093	1,265	-16%
May	1,296	1,293	0%
Jun	1,553	1,436	8%
July	1,551	1,512	3%
Aug	1,557	1,488	4%
Sep		1,370	
Oct		1,239	
Nov		1,297	
Dec		1,372	
Annual Peak	1,557	1,512	3%

Monthly Peak Demand - Extreme Weather

Month	Actual Peak Demand	Forecast (Extreme Weather) Peak Demand	% Diff
Jan	1,217	1,317	-8%
Feb	1,235	1,351	-9%
Mar	1,160	1,308	-13%
Apr	1,093	1,466	-34%
May	1,296	1,439	-11%
Jun	1,553	1,543	1%
July	1,551	1,635	-5%
Aug	1,557	1,634	-5%
Sep		1,625	

Oct		1,473	
Nov		1,283	
Dec		1,394	
Annual Peak	1,557	1,635	-5%

Interrogatory

#23. [Ref: C/1/1] Please confirm that EHM does not add any cost associated with a capital project to rate base until the project's assets have been put into service.

Response

Enersource does not add any cost associated with a capital project to rate base until the project's assets have been put into service. Please see Exhibit C / Schedule 3 / Tab 2 / Note 5.

Interrogatory

#24. [Ref: C/1/3] Please provide a detailed breakdown of the IT capital budget by line item, with comparables for 2006 (actual) and 2007 (forecast).

Response

[Please see attached spreadsheet.](#)

Interrogatory

#25. [Ref: C/1/6} Please advise the number of office personnel using the “office area of 72,000 square feet” at 3240 Mavis Road on a daily basis, breaking that number down by employees of the Applicant, employees of affiliates, and others. Please advise the net square feet per employee of office space, and compare to industry standards, if known. Please advise the total of all OM&A, amortization, and cost of capital amounts proposed to be charged to ratepayers in the Test Year for the use and occupation of the office space at 3240 Mavis Road, and the total of all such amounts to be paid by affiliates (directly or through overhead or other markups) or by others.

Response

The net square feet per employee of office space compared to industry standards are not known.

	Headcount
Enersource Hydro	323
Enersource Affiliates'	66
Total Headcount	389

All Enersource employees are based at 3240 Mavis Road.

Actual Square Feet	130,131
Garage	59,771
Other/Office Space	70,360

OM&A				
Costs	\$			1,948
Amortization	\$			215
Average Building + Land	\$	8,633	7.464%	\$ 644

Total Cost of 3240 Mavis Road	\$	2,807
Return on Assets	-	122
Facilities Recoveries	-	335
Charged to Ratepayers	\$	2,350

Interrogatory

#26. [Ref: C/1/7] Please file the original business case for the SCADA system when approved. Please quantify the savings in operating costs and capital expenses in the Bridge Year and the Test Year as a result of the SCADA system, and compare those figures to the forecasts of savings in the original business case. Please identify where (at as detailed a level as possible) those savings are reflected in the Bridge Year forecasts and Test Year budgets for OM&A and capital spending.

Response

Enersource's SCADA system has been in place for several years and the savings have been realized. There are no incremental savings that will be realized in the 2007 Bridge Year or in the 2008 Test Year.

Interrogatory

#27. [Ref: C/2/2, p.2] The Applicant has filed the System Capacity Report for 2007, dated September 2006. Please file the Applicant's System Capacity Report and Load Duration Curves Report for 2008.

Response

Enersource's 2008 System Capacity Report dated October 5, 2007 was prepared after the subject Application was filed and is attached to this response. Enersource will be able to provide observed 2008 load duration curves in early 2009.

Interrogatory

#28. [Ref: C/2/2, p. 3] Please provide the “detailed implementation plan”, the “detailed project schedule”, and the “detailed budget” for each of the CIS project and the Integrated Operating Model project.

Response

CIS

Please refer to attached files: Project Plan (Image), CIS RFP Evaluation document, RFP Cost Comparison and CIS Budget. Note that the Cost Comparison shows a total implementation cost of \$6.9 million for SPL 2 (Enersource & TH 50/50 split). This was the original budget. With the contingency funds of \$1 million, the total budget became \$7.9 million. Over time, additional costs resulted in a current budget estimate of \$10.8 million.

PROJECT DESCRIPTION INTEGRATED OPERATING MODEL

The Integrated Operating Model (IOM) Project, which will integrate the Automated Mapping/Facilities Management/Geographical Information System (AM/FM/GIS), and the Supervisory Control and Data Acquisition (SCADA) systems, is estimated to require \$2.3 million in funding. The project budget includes all hardware, software, implementation services, training, documentation, and internal costs.

The project is scheduled to begin in July, 2007 with a completion schedule of 18 months. A budget of \$1.2 million was proposed for 2007, with the remaining \$1.1 million required in 2008. The 2007 budget was prepared in September, 2006 and approved by the Enersource Hydro Mississauga (Enersource) Executive, and then the Enersource Corporation Board of Directors, as part of the Capital Budget approval process. The 2008 capital budget approval process is underway. A discussion of the business drivers and a brief technical description of the project follow.

The AM/FM/GIS and SCADA installations are mature, with a number of applications in use throughout both the Operations and Engineering areas. Many improvements to business processes have been realized over the past several years, and Enersource’s reliability, safety, and productivity records are excellent. However, continuous improvement is an important corporate objective if we want to continue to be a leader in the industry. Over time, a number of issues have been identified, that once resolved, will allow us to be even more successful.

The Enersource Operating personnel must work with several sources of information in order to have a complete view of the details of the distribution system. These sources include the

SCADA system, the AM/FM/GIS, and paper schematic maps, all of which are briefly described below:

SCADA

The SCADA system provides remote monitoring and control as well as historical data archiving and trending capability for 68 substations and 176 pole-mounted and pad-mounted automated switches located throughout the electrical distribution system. It also provides remote monitoring of the system status at 10 Hydro One TS's supplying the Enersource distribution system.

AM/FM/GIS

The AM/FM/GIS captures both geographical and facility information about Enersource's plant in the field. A map of the City of Mississauga showing the streets and lots is overlaid with equipment information reflected in its approximate location. Non-plant items such as municipal addresses and easements are also captured. In total, Enersource has information regarding 872,000 items. An intelligent "connectivity model" is maintained in the system such that each item of plant recognizes its upstream and downstream devices.

Paper-Based Operating Schematics

Although the AM/FM/GIS model is heavily utilized by the System Control Centre (SCC), the maps do not reflect the real-time electrical network status. SCADA, which provides monitoring and control of field devices, has a limited data set. Therefore, the SCC utilizes operating schematic maps, which reflect a view of the same equipment already represented in some way, on the other two systems.

The maps are hung on swing panels at which point coloured pins are placed to show the most current status of the devices in Enersource's distribution system. In effect, the information on the maps becomes real-time with the placement of the pins.

There are a number of consequences resulting from the need to work with so many data sources. First of all, the inconvenience of working with several map products and systems slows down all aspects of the decision-making process and impacts the efficiency of the SCC. During periods of heavy activity, such as storm conditions, the extra time needed to make decisions may also lead to reliability and safety concerns.

Secondly, the non-integrated nature of the data impacts other departments such as System Planning, Engineering Design, and Construction. When a decision can be made quickly, and with a substantial and accurate data set, the quality of the decision is enhanced. It is reasonable to believe that the multi-step process required for planning and design, is resulting in some cost inefficiencies.

A third impact of the multiple data sets is the number of resources that must be assigned to the task of keeping them up-to-date. Along with the obvious inefficiencies this implies, it is certain

that over time, the data sets will diverge. More productivity will be lost as end-users of the three map products have to investigate which version truly reflects the field conditions.

The fact that the Operations group does not completely rely on the AM/FM/GIS data impacts the overall quality of that data. If it is not their primary data source, there is less impetus for them to seek out and identify errors in it, and the full benefits of their involvement with the model are not realized throughout the rest of the engineering departments. The significant investment that has been made in data collection and maintenance on AM/FM/GIS should be fully leveraged.

Finally, and perhaps most critically, there is risk of losing the real-time switch status if there is an SCC emergency, or if the building itself becomes inaccessible. The SCC pinned maps cannot be reproduced easily. In fact, even the loss of one pin location can create a safety risk for our crews and the public.

These business issues and the determination to resolve them have led to the initiation of the IOM project. Its primary objectives are to:

- Establish a single Interface to operate the distribution system;
- Use the AM/FM/GIS connectivity model to build the IOM and for the ongoing updates of the IOM;
- Eliminate the swing board paper maps in the System Control Centre;
- Establish a workflow for accurately managing distribution network updates.

Meeting these objectives will enable Enersource's personnel to manage and operate the distribution system more effectively and efficiently. Improved tools for analyzing system conditions will assist the SCO's and the engineering and design departments in their decision-making processes, both under normal and emergency conditions. The resources required to maintain the various map products can be more appropriately deployed. The risk of losing our real-time status information will be eliminated by having the status of devices stored in a database.

Interrogatory

#29. [Ref: C/2/2.1] Please reconcile the figure of \$129.23 OM&A per customer to the 2006 actuals, the 2007 forecast, or the 2008 budget for OM&A.

Response

[Please see the response to CCC interrogatory #12.](#)

Interrogatory

#30. [Ref: C/2/3] EHM has stated that its existing CIS is 8 years old and is fully depreciated, so is being replaced. With respect to the proposed new CIS:

- a. What is the current customer billing system that EHM is using?
- b. What should be the average useful life of the CIS system within the industry? If the industry average useful life of the CIS system is longer than 8 years, please explain why did EHM choose a CIS system with a below-average expected life.
- c. Please describe the circumstances that resulted in the vendor of the existing CIS ceasing to support it after two years.
- d. What is the expected useful life of the new CIS system? What is the depreciation rate that will be applied to the new CIS system?
- e. On page 3 of C/S2/T3, it was stated that “in the future Enersource’s cost per customer may be lower because of the ability to share development costs related to regulatory charges”. Please explain.
- f. On page 3 of C/S2/T3, it was stated that “there is the potential for the continued reduction of on-going costs as the other interested LDCs join Toronto Hydro and Enersource in implementing the core CIS Ontario Market Ready solution”.
 - i. Please provide details on CIS Ontario Market Ready solution.
 - ii. If other interested LDCs jointly participate in implementing the core CIS Ontario Market Ready solution, how would that contribute to Enersource’s ability to reduce its on-going costs?
- g. Please provide a copy of the RFP for the new system.
- h. Please provide a copy of the detailed budget for the new CIS, broken down between amounts to be paid by Enersource and amounts to be paid by Toronto Hydro, and further broken down between spending in 2007 and 2008.
- i. Please provide copies of any communications from EnWin, Horizon, London Hydro or Powerstream explaining their reasons for not joining with Enersource and Toronto Hydro in the purchase of the new CIS.
- j. Toronto Hydro has stated in its evidence (THESL Evidence D1/T10/S2-4/pg4) that one of “the main benefits of moving to a core SPL CC&B CIS solution and partnering with EHM is to reduce future overall costs per customer, facilitate regulatory compliance, improve customer service, increase productivity”.

- iii. **Please advise whether similar benefits are achievable at EHM. Please quantify those benefits.**
- iv. **Please provide EHM's current customer billing & customer service cost per customer.**
- v. **Please provide EHM's future expected customer billing & customer service cost per customer after the SPL CIS system is put in service.**
- k. **What is the estimated salvage value of the CIS system being replaced?**
- l. **What is the tax treatment of the replacement of the old CIS with the new CIS? Please calculate the amount of the CCA tax shield associated with the entry into service of the new CIS, and show where it is reflected in the PILs calculation for the Test Year filed as part of this Application.**

Response

a. Enersource uses an Orcom E-CIS that has been extensively modified for the de-regulated Ontario market.

b. Enersource does not have any information regarding the average useful life of a CIS system within the industry. Enersource applied a depreciation rate of 5 years consistent with the depreciable life authorized in the Accounting Procedures Handbook. Enersource's decision to purchase a new CIS was not based on cost benefit but on business issues relating to the future requirement to support time of use billing and the risks associated with the fact that the existing Orcom E-CIS has not been supported by the vendor since 2000. Changes that are required to the current CIS are made with the assistance of an external programming team which is familiar with the Orcom E-CIS. Although the programmers supporting the application are still available and continue to work for us as required, the organization through which we had contracting services went bankrupt in 2005. In addition, market requirements have exceeded the functionality of the existing CIS (eg., it cannot support Time of Use commodity rates).

c. Enersource purchased the current CIS with the intention of obtaining a system that worked in de-regulated markets and was supported by the vendor (eg., who would adopt and support new capabilities as technologies improved).

The current Customer Information System (CIS) was purchased from Orcom Solutions and implemented in 1999 as a year 2000 compliance project. The new requirements for the open electricity market in Ontario were issued within 12 months of implementation. The CIS had to be heavily modified to meet the new regulatory requirements.

Because of the changes required to support retailer transactions, the CIS has not been supported by Orcom since the year 2000. Orcom was approached to make the necessary changes for Market Opening, but Enersource and Orcom were unable to come to agreement about the cost of making the changes and the way the changes would be delivered and implemented.

When the CIS was purchased it was not Enersource Hydro Mississauga's intention to implement an in-house supported custom application, particularly when changing regulation requires continual significant upgrades. Enersource prefers to rely on a vendor supported application in order to acquire the continuous improvements that a vendor normally provides through a maintenance agreement.

d. The CC&B system is part of Oracle's Utility Application Suite. The system is one of the leading utility billing systems in the world. Enersource plans to adopt the upgrades provided by Oracle on a timely basis and continue using CC&B or its successor products indefinitely. A depreciation rate of 5 years will be applied to the new CIS system.

e. Currently, Enersource bears all the costs of supporting and modifying the existing CIS. By implementing a CIS jointly with Toronto Hydro, Enersource and Toronto Hydro will be able to share these costs.

During implementation Enersource and Toronto Hydro are sharing cost of vendor implementation, configuration of common business practices, common customization, common interfaces, test scripts, training materials and documentation of common business practices.

Some level of customization is always required in a complex "mission critical" application. Enersource and Toronto Hydro have committed to have 95% alignment of business processes. Post go-live if both organizations require the same customization, then Enersource and Toronto Hydro will share the costs. This will reduce the costs of customization by one half.

If Enersource were not involved in a joint implementation with Toronto Hydro then Enersource would need to pay for implementation, configuration, customization, test script development, training materials development and documentation on its own.

f. i. The CIS Ontario Market Ready solution is Oracle's CC&B application configured and customized to meet Ontario regulatory requirements and business practices, upgraded by the vendor to meet regulatory requirements as they change over time.

f. ii. Enersource expects that as other interested LDCs join in implementing the core CIS Ontario Market Ready solution that the associated fixed costs will be spread over more participants thereby lowering each participant's average responsibility for these fixed costs.

g. Please refer to attachment.

h. Please refer to SEC #28.

i. There are no written records that explain why these distributors decided not to join.

j. i. The benefits were not explicitly quantified but it is expected that future costs associated with regulatory compliance and customer service will be avoided. Enersource expects that by participating with THESL in moving to a core SPL CC&B CIS solution that its overall cost per customer will be lower than it would have been if Enersource had implemented this solution on its own.

j. ii.	2006	2007	2008
Customer Service & Billing Operations	7,256	8,597	9,058
# of Connections	230,679	232,844	238,914
Cost per Connection	\$ 31.45	\$ 36.92	\$ 37.91

j. iii. Enersource's future expected billing & customer service cost per connection after the SPL CIS system will be the same. The cost of the CIS will be included in rate base.

k. The CIS currently in place has no salvage value.

l. In the filed rates application the new CIS was put into class 45 of the Capital Cost Allowance for the PIL's calculation, which has a 45% allowance rate. Upon further investigation, it was discovered that the nature of the asset lends itself more to class 10 and not class 45. Class 10 has a 30% cost allowance rate, which is more in line with the life expectancy of the asset used in our depreciation calculation.

The revised CCA for 2008 and 2009 would be as follows:

CCA for the first two years are:

CCA 2008 (\$7,914@30%/2) =	\$1,187
CCA 2009 (\$7,914 - \$1,187)@30% =	\$2,018

Depreciation is over 5 years starting in January 2008 as well.

Depreciation for the first two years are:

Depreciation 2008 (\$7,914/5/2) =	\$791
Depreciation 2009 (\$7,914/5) =	\$1,583

Interrogatory

#31. [Ref: C/2/4] With respect to metering capital expenditures:

a. Please complete the following table:

		2006 Historical	2007 Bridge	2008 Test
A	Capital Budget per Wholesale Meter	\$18,660.00	\$55,175.00	\$72,500.00
B	Number of Wholesale Meters	8	14	2
C	Capital Budget per Conventional Meter	\$322.88	\$1,525.26	\$1,587.31
D	Number of Conventional Meters *	3,424	550	560
A*B+ C*D	Total Capital Budget - Meters	\$1,254,816.00	\$1,611,345.00	\$1,033,895.00
	Addition to Rate Base (C/S3/T3)	\$1,254,816.00	\$1,611,345.00	\$1,033,895.00

* - Excludes new condo's customer metering.

b. Please provide the historical average capital cost per conventional meter and historical average capital cost per wholesale meter under this program.

- i Historical Average Capital Cost for Wholesale Meters is \$18,660.00
- ii Historical Average Capital Cost for Conventional Meters is \$322.88

c. Please explain any significant variance between budget and historical average capital cost for both conventional meter and wholesale meter.

For the calendar year 2006, Enersource completed meter only upgrades for 8 wholesale meters located at one Transmission Station Yard. The meter only upgrades were completed on Measurement Canada approved Instrument Transformers and thus met the IESO Market Rules and Measurement Canada regulations. In 2007, Enersource completed meter only upgrades for 6 wholesale meters located at two separate Transmission Station Yards. The six wholesale meter only upgrades were completed on Measurement Canada approved Instrument Transformers and thus met the IESO Market Rules and Measurement Canada regulations. Also in 2007, Enersource completed full wholesale metering installations to comply with IESO Market Rules and Measurement Canada regulations. The 8 full wholesale meters were installed for separate Transmission Stations feeders and each installation required new instrument transformers, metering enclosures and new wholesale meters to meet the IESO Market Rules and Measurement Canada regulations. In 2008 calendar year, Enersource forecasts installation of new full wholesale metering equipment (two meters) at one Transmission Station.

In regard to conventional meters, Enersource installed residential 2,928 conventional meters in 2006. As a result of the smart metering, Enersource now installs smart meters on all new

residential meters and thus no residential conventional meters are included in the 2007 and 2008 figures.

Interrogatory

#32. [Ref: C/3/2 and C/3/3] Please extend these two tables to cover the period 2002-2008.

Response

[Please refer to the attached spreadsheet.](#)

Interrogatory

#33. [Ref: C/3/4] With respect to the capital expenditures budget:

- a. For 2007 bridge year capital expenditure budget, please restate each capital line item by separating January-September 2007 actual spending and October-December 2007 forecast spending.
- b. For each of the three years set out in the Schedule, please show the amount closed to rate base, and the amount carried forward to a future year.
- c. With respect to smart meters:
 - vi. Please file EHM's 2007-2008 smart meter implementation plan.
 - vii. Please provide all smart metering costs by component: meter purchase, meter installation, WAN, AMCC, AMRC, and Other.
 - viii. Please calculate smart metering capital unit cost.
 - ix. Please describe and list all cost savings during the Test Year as a result of the Smart Meter Initiative, both in capital budget and OM&A expenses.

Response

- a. Please refer to the attached spreadsheet.
- b. Please refer to the attached spreadsheet.
- c.
 - i. The original 2006 SMIP remains the relevant document with updates stated in Exhibit G / Schedule 2 / Tab 6.
 - ii. Due to confidentiality issues, Enersource is unable to provide the requested information of capital costs.
 - iii. EHM unit costs for Residential, Small Commercial, and General Service less than 50 kW customers for 2008 is \$193.95.
 - iv. Please see the response to CCC interrogatory #15.

Interrogatory

#34. [Ref: C/4/1] With respect to the 2007 System Capacity Report:

- a. Please explain the difference between the figure of \$30,557 capital budget for 2007 on page 3 of this report, and the reported forecast of \$43,488 for the Bridge Year. Please provide a detailed reconciliation of the two figures.
- b. P.7. Please describe how the Applicant is taking government and utility demand response programs into account in forecasting peak demand.
- c. P.14. For each of the “continuation of” projects referred to, please provide the multi-year details on the project, including both past and future years, and a description of the current status of the project.
- d. P.16. Please explain why a spare transformer is required. Please identify operational differences between the prior period, without a spare transformer, and the proposed future period. Please confirm that, until brought into service, the spare transformer will not be added to rate base.
- e. Please confirm that the chart below correctly sets out certain of the recommended projects and their forecast impacts:

Project	Cost	Payback	Annual Loss Savings	Annual Customer Savings - \$	Annual Customer Savings - Min
Falconer Drive Phase 2	\$1,150,000	9.3	\$2,500	\$105,000	21,000
Argentia 58F2	\$500,000	4.0	\$1,500	\$125,000	25,000
Council Ring Road Phase 2	\$1,000,000	3.6	\$1,500	\$275,000	55,000
Pheasant Run Phase 2	\$1,000,000	4.0	\$1,500	\$250,000	50,000
Burnhamthorpe/Pony Trail Phase 1	\$1,000,000	5.7	\$1,500	\$175,000	35,000
Garnetwood Chase	\$800,000	5.3	\$1,500	\$150,000	30,000
Bloor/Central Parkway	\$500,000	1.4	\$1,500	\$350,000	70,000
Feeder Overhauls	\$375,000	2.1	\$5,000	\$175,000	35,000
Overhead Rebuilds	\$900,000	4.0	\$2,000	\$225,000	45,000
Primary Distribution Equipment Replacement	\$600,000	2.2	\$0	\$275,000	55,000
Underground Cable & Splice Replacement	\$1,400,000	2.8	\$6,000	\$500,000	100,000
Underground Transformer Replacement	\$400,000	2.6	\$2,000	\$150,000	30,000
Overhead Transformer Replacement	\$200,000	2.6	\$2,000	\$75,000	15,000
TOTALS	\$9,825,000		\$28,500	\$2,830,000	566,000

- f. Please confirm that these projects are expected to reduce customer minutes of interruption by 11.7% in the Test Year relative to 2006 actuals. Please identify where this substantial reliability improvement is reflected in operating costs or other impacts in the Application.**
- g. Please identify where the savings in losses is reflected in the loss factor for the Test Year.**
- h. Please describe the decision-making process for project inclusion or exclusion, and in particular the importance, if any, of payback period. Please describe why projects as diverse as 1.4 years payback and 9.3 years payback would be recommended under the same criteria.**
- i. P.30 Please provide a chart similar to the chart on page 542 of the Application showing Rolling Stock replacements, including vintages, for each of 2005 and 2006. Please provide a chart forecasting Rolling Stock replacements, including vintages, for the Test Year. Please advise how many light vehicles are being retained although having been in service longer than 3 years. Please reconcile the 3 year replacement in this chart with the 3-5 years in C/5/1, p. 64, and the 4 year amortization period for accounting purposes.**

Response

- a. The capital spending referenced in the System Capacity Report pertains to distribution infrastructure only. The \$43.488 million is Enersource Hydro's total capital spending in 2007.
- b. To date, utility demand response programs have not had any discernable effect on peak demand. Enersource expects that in 2008 it may be able to reduce peak demand by 10 to 15 MW through these programs.
- c. Other type of equipment that is part of a multi-year replacement project is Remote Telemetering Unit ("RTU") replacement. For automation, we are in our second year of a five year plan to replace 100 pole top RTUs. To date, we have replaced 20 and we will replace the remaining 80 over the next 3.5 years. The majority of the RTUs have reached end of their useful life. Further, our Substation RTUs are being replaced as they are also approaching the end of their useful life. To date, we have replaced/installed 6 substation RTUs and we still need to replace 45 units. It is estimated that it will take the next 7 years to replace all remaining station RTUs.
- d. A spare transformer is required to prevent prolonged customer outages. This may occur if a transformer fails and the potentially affected customers:
 - cannot be served by another substation transformers; or

- may require a long time period to be moved to another substation transformer, subtransmission circuit and or Hydro One TS transformer in order to avoid overloading.

The spare transformer is added to rate base when it is placed into service the first time.

e. These are estimates based on past experience. Accurate pricing requires that the project be full designed. Please note that recent materials prices and labour rates increases, and soil conditions (eg., constructing in shale) can dramatically affect cost on a project.

f. If all other factors were to remain constant these projects, on their own, are projected to reduce customer minutes by 566,000 or 11.7% of Enersource's total customer minutes from 2006. This reliability improvement will act to avoid future incremental maintenance costs.

g. Enersource's overall projected loss factor for 2008 incorporates the assumed benefits of the identified investments. Enersource does not estimate the distribution system loss benefits at a project specific level.

h. Please refer to the response to VECC interrogatory #18.

i. The attached spreadsheet provides the 2005, 2006, 2007 and 2008 Budgeted Rolling Stock Replacements. Enersource retains 28 light vehicles that are older than 3 years. The 3 year replacements are executive cars and are being replaced to comply with employee contracts. With respect to the amortization period, rolling stock is treated as identifiable assets. These assets are booked individually with all the necessary details such as asset cost, acquisition date, asset life, depreciation rate and other information. Thus, when these assets are disposed of or replaced the undepreciated balance and remaining life are readily identifiable.

Interrogatory

#35. [Ref: C/5/1] With respect to the business cases for major capital projects:

- a. Please provide the business case for the Integrated Operating Model.
- b. P.7 Please reconcile the forecast of 2.6% load growth over the next few years with the estimates used in the Application.
- c. P. 40 Please reconcile the statement “Typical life expectancy for underground cable is approximately 35 years” with the many recommendations in the System Capacity Report to replace underground cable after 30 years.
- d. P.51 Please provide the Applicant’s latest comparisons of SAIDI and SAIFI “to similar utilities”. Please list the utilities to whom the comparison was made.
- e. P. 68 Please provide the actual business case used in the approval process for the Grounds and Buildings spending.
- f. P.63 Please provide the actual business case used in the approval process for the CIS system.

Response

- a. Please see the response to SEC interrogatory #28.
- b. The reference cited refers to load growth on the 44kV system and not on the overall system. Over the next few years, Enersource’s peak demand growth is forecasted to be greater than the forecasted energy consumption growth (please see Exhibit B/ Schedule 3/ Tab 2/ pages 2 and 3). Enersource forecasts that demand in the area of Winston Churchill Blvd and Hwy 403 as a high growth area forecasted to continue growth in the next few years.
- c. Underground primary cables can start to experience consistent failures as early as 20 years or they may last as many as 40 years without experiencing any failures. There is no proven method for testing underground cables to predict failures or remaining life. Although age is considered, the best indicator for replacement remains the number of failures. Areas are considered for replacement only once they have started experiencing failures. For some areas the failures becomes unacceptable when they are between 25 and 30 years old, which is less than the typical

35 year life expectancy. Many areas are older than the 35 years typical life expectancy and have not experience failures necessitating replacement.

- d. The comparisons are taken from the Canadian Electrical Association's 2006 Annual Service Continuity Report on Distribution System Performance in Electrical Utilities. This is a voluntary reporting process for Canadian Utilities, where the data is distributed to all participants provided they agree to keep the data confidential.
- e. Grounds and Building spending is determined on a case by case basis and is approved following standard corporate policies and procedures.

Please see the response to Board staff interrogatory #1.

- f. The decision to implement a CIS jointly with Toronto Hydro was a strategic decision and was not based solely on a cost benefit analysis. In-house maintenance of a 'mission critical' application requiring constant change in response to changing regulations is not prudent for Enersource. A new CIS was required to support the future requirement of time of use billing. Partnering with another utility to implement a leading application supported by Oracle reduces risk to Enersource and to our customers, improves functionality and reduces the costs of customization and regulatory change over time.

Please see the response to SEC interrogatory # 28.

Interrogatory

#36. [Ref: D/1/2. p.3] Please complete the following table Please confirm that the insulator washing program is a standard program and is carried out in a similar fashion by other Ontario LDCs.

		2006 Actual	2007 Bridge	2008 Test
Operating Stats	Distribution & sub-transmission circuits (km)		1,620	
	Poles (#)		26,000	
	Switches (#)		16,000	
	Transformers (#)		5,600	
C=A*B	Insulator Washing Program (\$K)			
A	Unit Cost- Insulator Washing (\$/unit)			
B	# of Unit-Insulator Washing (#)			
	Percentage of New Insulators / Total Insulators			
F=D*E	Infrared Survey of Lines Program (\$K)			
D	Unit Cost- Infrared Survey of Lines (\$/unit)			
E	# of Unit-Infrared Survey of Lines (#)			
G	Other (\$K)			
C+F+G	Total Overhead Maintenance & Repairs (\$K) (D/S2/T2)	1,645	1,976	1,997
	Total Spending Increase %		20% increase	1% increase

Response

Enersource's insulator washing program is similar to that of some other Ontario LDCs, although we are not certain if all Ontario LDCs have a similar program. Enersource requires a substantial program because there are several 400 series highways that run through Mississauga as well as many heavily traveled municipal and regional roads. The primary focus of the program is to remove road salt and other contamination from the overhead insulators. Insulator washing is weather dependent. If contamination is not removed during mild and moist winter conditions the system will be highly susceptible to pole fires which generally results in significant damage to plant and outages. In 2006 conditions were not favourable for washing insulators during the winter and also did not put us at significant risk for poles fires. As a result we spent only a small portion of the budget. In 2007 we will be slightly under budget as our system was not exposed to the snow and resulting salt until late January.

		2006 Actual	2007 Bridge	2008 Test
Operating Stats	Distribution & sub-transmission circuits (km)		1,620	
	Poles (#)	***	26,000	***
	Switches (#)	***	3,300	***
	Transformers (#)	***	5,600	***
C=A*B	Insulator Washing Program (\$K)	34	90 (forecast actuals)	135
A	Unit Cost-Insulator Washing (\$/hr)	195	250	268
B	# of Unit-Insulator Washing (hr)	175	357	504
	Insulators	55%	60%	65%
F=D*E	Infrared Survey of Lines Program (\$K)	13	16.7	20
D	Unit Cost- Infrared Survey of Lines (\$/day)	\$650/Day	\$670/day	\$715/day
E	(This is an daily contract which is typically 20 Days to scan all of Enersource Overhead System & 5 to 10 days of trouble shooting problem areas) of Unit-Infrared Survey of Lines (#)	20 days	25 days	28 days
days				
G	Other (\$K)	1,598	1,869	1,873
C+F+G	Total Overhead Maintenance & Repairs (\$K) (D/S2/T2)	1,645	1,976	1,997
	Total Spending increase		20% increase	1% increase

*** do not have this data

Interrogatory

#37. [Ref: D/1/2/, p.6-8] Spending on Substations operations include 2 major work programs: corrective maintenance (to respond to emergency and corrective maintenance work requirement), and planned maintenance (to maintain the entire substation on a 5 year cycle and auto-switches on a 2 year cycle). On page 8 of D/S1/T2, EHM has indicated that “costs are increasing due to the need to increase maintenance on power transformers to reverse an observed trend of increased failures”.

- a. Please provide any historical data EHM has available with respect to “trend of increased failures” of power transformers. What are the major causes for those failures?
- b. Why was such trend of increased power transformer failures not acted on earlier and spending increased earlier?
- c. Please complete the following table.
- d. Please explain and comment on any significant unit cost year over year variation. Please separately identify labour escalation factor.
- e. If the entire substation system is progressively maintained on a 5-year cycle and the automated switches on a 2-year cycle, what is the rationale for the jump in costs in 2007?

Response

a. There is no increase in power transformer failure at Enersource. The claimed trend has been observed by the industry. The industry is forecasting an increasing amount of power transformer failure due to lack of:

- on-line monitoring;
- maintenance; and
- power transformer life assessments.

b. In order to ensure that this does not become a problem at Enersource, we are using preventative measures such as increasing station maintenance, enhancing oil testing (eg., water content and furan analysis) of our power transformers and performing transformer life assessments.

c. Please see the table below.

		2006 Actual	2007 Bridge	2008 Test
A	Corrective Maintenance (\$K)	268	315	330

	Cost Driver			
	Unit Cost (\$/unit)			
B	Planned Maintenance (\$K)	450	900	954
	Cost Driver			
	Unit Cost (\$/unit)			
C (Property taxes and Grounds & Buildings)		\$670	\$750	\$760
A+B+C	Total Substations Operation (\$K)	1,388	1,965	2,044
	Yr/Yr Increase (\$ & %)		\$577K, or 41.6%	\$79K, or 4%

d. The major reason for the increase in costs is related to labour, specifically the hiring of apprentices for the substation department. Further, Enersource will retain a consultant to assist with transformer life assessments.

e. Please see the response to part d.

Interrogatory

#38. [Ref: D/1/2, p. 12/13]. Please identify in the Application the amounts and locations of the savings in OM&A or capital costs arising out of the fleet management system.

Response

OM&A costs arising out of the fleet management system are recovered through fleet recovery rates. Please refer to Exhibit D / Schedule 2 / Tab 1 in the 2008 Rate Application and to the response to VECC interrogatory #9.a.

Interrogatory

#39. [Ref: D/1/2, p. 15] Please advise how many transformers the Applicant has that were installed on or before December 31, 1981. Please advise the normal service life of a transformer in this category.

Response

It is our estimate that there are 12,500 transformers that were installed prior to December 31, 1981. The normal service life of a transformer is 25 years. The actual life will vary considerably depending on what the transformer was exposed to during its life.

Interrogatory

#40. [Ref: D/1/3] With respect to customer care:

- a. **P. 3. Please provide a copy of the previous outsourcing contracts. Please provide a copy of a business case or other analysis at the time forming the basis for the decision to bring those services in-house, and/or forming the basis for the decision not to renew or replace the existing outsourcing arrangements.**
- b. **P.7 Please provide estimates of all cost savings the Applicant will experience in the Bridge Year and in the Test Year as a result of IVR and e-commerce offerings to customers (such as electronic bill presentment and payment). Please file prior year business cases with respect to IVR and e-commerce projects, and compare current estimates of savings to forecasts used in those business cases.**
- c. **P. 10. Please provide the headcount for the Customer Care Management Group, and a breakdown of their budget, with similar figures for 2006 and 2007.**

Response

a. Enersource declines to provide the requested contracts. The pricing and terms and conditions are considered competitive and hence confidential.

b. Enersource did not rely on formal business cases to support the implementation of IVR and e-commerce offerings. These services were evaluated from a cost minimization perspective. These innovations have been available to customers for several years. As a result any savings attributable to these services have been achieved and are incorporated in Enersource's projected expenses.

c. Information on the head count in the Customer Care Management group is provided at Exhibit A/ Schedule 11/ Tab 1. Information on the budget of this group is provided at Exhibit D/ Schedule 1/ Tab 3.

	2006	2007	2008
Headcount	74	76	77
	Actual	Forecast	Budget
CUSTOMER SERVICES ADMIN	1,613	1,705	1,864
SETTLEMENTS	624	903	928
CUSTOMER ACCOUNTS	3,789	4,611	4,769
CUSTOMER BILLINGS	523	493	517
METERING	707	885	980
Total	7,256	8,597	9,058

Interrogatory

#41. [Ref: D/1/6] Please provide a copy of the Applicant's Incentive Compensation Plan, together with any documents setting forth the performance metrics for the Bridge Year and the Test Year.

Response

1) Description

The incentive compensation plan for Enersource Hydro Mississauga is based on the following performance measures:

- Reliability
- Safety
- Performance Based Regulation
- Enersource Net Income

2) Performance Measures

List of specific performance measures:

RELIABILITY: Annual Average Outage per Customer

- SAIDI [System Average Interruption Duration Index] [in minutes]
- SAIFI [System Average Interruption Frequency Index] [in quantity]

SAFETY:

Number of Preventable Lost Time Injuries

PERFORMANCE BASED REGULATION: Service Quality PBR Indicators

Customer Service

- Incoming calls answered by Customer Service Representative within 30 seconds

Connection of New Services

- <750 volts connected within 5 working days from the day on which all conditions of service are satisfied
- >750 volts connected within 10 working days from the day on which all conditions of service are satisfied

Underground Cable Locates

- Completion within 5 working days of a customer's request

Appointments

- Appointments at customer's premises met within appointed time

Written Response to Inquiries

- Written response to inquiries from customer or agent of customer, within 9 working days following receipt of request

Emergency Response

- Emergency trouble calls response within 60 minutes.

ENERSOURCE NET INCOME BEFORE TAXES

Identification of Stakeholder Who Benefits:

- Reliability – Rate Payer
- Safety – Rate Payer/Employees
- Performance Based Regulation – Rate Payer
- Enersource Net Income – Shareholder – Self Funding (Not included in 2008 rate application expenses)

Interrogatory

#42. [Ref: D/1/9, p.3] Please quantify the savings in OM&A and/or capital costs associated with the computerized load flow program, and identify where those savings are reflected in the Application.

Response

Please see Exhibit C/ Schedule 1/ Tab 5/ page 6. At this time, Enersource's computerized load flow program is not fully implemented; comprehensive calibration to Enersource's distribution system is required, hence not all potential savings have been realized. Enersource relies on the program to model the effect of switching operations on the distribution system to ensure that the impact on the system is understood as well as possible. In this respect the program allows Enersource to minimize switching operation costs and customer interruptions are minimized.

Interrogatory

#43. [Ref: D/1/11] Please provide a detailed breakdown of amounts to be paid to or received from affiliates during the Test Year, including in each case a) the total amount of each expenditure being allocated between the utility and non-utility affiliates; b) the cost driver for each line item (and the numeric breakdown of that cost driver, e.g. relative headcounts), and c) with respect to both the totals being allocated and the utility allocation, the 2006 actuals and 2007 forecast figures.

Response

Please see attachment for amounts paid.

Please see the response to SEC interrogatory #16(b) for amounts received.

Interrogatory

#44. [Ref: D/1/11] Please identify where in the Application the expenses of the utility relative to its Board of Directors, or that of its parent company, can be found. Please provide a chart showing a breakdown of those expenses, by category and by year, from 2002 to 2008.

Response

The Management Fee charged by Enersource Corporation recovers Enersource Hydro's share of the Enersource Corporation's Board of Directors.

Items Paid to/Received from
affiliates

	02-'08 Alloc %	2008 Test Yr	2007 Bridge Yr	2006 Actual	2005 Actual	2004 Actual	2003 Actual	2002 Actual
<u>Enersource Hydro</u>								
<u>Mississauga:</u>								
Corporate Governance/Board of Directors	90.00%	189	270	391	371	282	222	243

Interrogatory

#45. [Ref: D/2/2] With respect to proposed OM&A Expenditures:

a. Please confirm that the data in the following table is correct:

OM&A Expenses (Ex D/S2/T2)							
	06 Actual	07 Forecast	08 Budget	07 vs. 06		08 vs. 07	
		\$'000		\$'000	%	\$'000	%
Control System	1,707	1,672	1,837	35	-2.1%	165	9.9%
Corporate Records	585	792	908	207	35.4%	116	14.6%
Grounds & Buildings	1,539	1,785	1,946	246	16.0%	161	9.0%
Substation Operations	1,388	1,965	2,044	577	41.6%	79	4.0%
System Planning	205	292	372	87	42.4%	80	27.4%
Trouble Truck	102	107	106	5	4.9%	1	-0.9%
Cable Locates	570	639	656	69	12.1%	17	2.7%
UG Mtce & Repairs	2,073	2,215	2,275	142	6.8%	60	2.7%
OH Mtce & Repairs	1,645	1,976	1,997	331	20.1%	21	1.1%
Tree Trimming	694	765	770	71	10.2%	5	0.7%
Garage (Fleet)	1,523	1,612	1,694	89	5.8%	82	5.1%
OH Construction	685	764	805	79	11.5%	41	5.4%
Industry/Commercial Inspections	884	775	799	109	-12.3%	24	3.1%
Stores	843	975	1,128	132	15.7%	153	15.7%
<i>Total Operations</i>	<i>14,443</i>	<i>16,334</i>	<i>17,337</i>	<i>1,891</i>	<i>13.1%</i>	<i>1,003</i>	<i>6.1%</i>
Customer Services Admin	1,613	1,705	1,864	92	5.7%	159	9.3%
Settlements	624	903	928	279	44.7%	25	2.8%
Customer Accounts	3,789	4,611	4,769	822	21.7%	158	3.4%
Customer Billings	523	493	517	30	-5.7%	24	4.9%
Metering	707	885	980	178	25.2%	95	10.7%
<i>Total Customer Services</i>	<i>7,256</i>	<i>8,597</i>	<i>9,058</i>	<i>1,341</i>	<i>18.5%</i>	<i>461</i>	<i>5.4%</i>
<i>Admin</i>	<i>3,580</i>	<i>4,216</i>	<i>4,539</i>	<i>636</i>	<i>17.8%</i>	<i>323</i>	<i>7.7%</i>
<i>IT Support</i>	<i>3,896</i>	<i>4,682</i>	<i>5,275</i>	<i>786</i>	<i>20.2%</i>	<i>593</i>	<i>12.7%</i>
Total OM&A	29,175	33,829	36,209	4,654	16.0%	2,380	7.0%

b. For each highlighted OM&A expense item year over year variance, please identify cost driver(s), and explain cost variances.

- c. **Please list and quantify any portion of OM&A expenses by each line item from 2006-2008 that was accrued and not paid out in the year in which it is recorded.**
- d. **For 2007 bridge year OM&A spending, please restate each OM&A line item by separating January-September 2007 actual spending and October-December 2007 forecast spending, including and excluding accrued portion.**

Response

- A) Yes the table is correct. Please see the response to Board staff interrogatory #31.
- B) Highlighted Items – (Please see Board staff interrogatory #31 for more information)
 - a. Corporate Records – Cost Driver – Headcount
 - b. Grounds and Buildings – Cost Drivers – Age of Buildings and usage – Repairs and Maintenance
 - c. System Planning – Cost Driver – Headcount
 - d. Industry/Commercial Inspections – Manpower – Vacancies and cost allocations
 - e. Stores – Cost Driver – Headcount
 - f. Settlements – Cost Driver – Headcount
 - g. Customer Accounts – Cost Driver – Headcount and inflation (Bill delivery)
 - h. Customer Accounts – Cost Driver – Headcount – Vacancies and new positions
 - i. Metering – Cost Driver – Headcount
 - j. Admin – Cost Driver – Headcount
 - k. IT Support – Cost Driver – Headcount and IT support costs
- C) In preparing its financial statements, Enersource follows GAAP. GAAP prescribes that any product or service received in the accounting period for which no invoice has been received, an accrual must be made.

In preparing forecasted financial statements, accrued items on Enersource's balance sheet include major items where it is known that an invoice will not have been received at year end, most notably, the IESO invoice. Due to the nature and complexity of the regulated business operations, it is too difficult to make an estimation of OM&A goods and services received prior to year end but not yet invoiced. As such, a breakdown of accrued OM&A costs is not available for forecasted years and the requested information cannot be provided.

- D) Due to the discussion in part C), this answer cannot be provided.

Interrogatory

#46. [Ref: D/2/3.1] Please complete the following table, and explain the material variances from 2006 to 2007, and from 2007 to 2008:

	2006 Actual	2007 Bridge	2008 Test
# of bills (D/S2/T3.1)	1,197,222	1,217,586	
# of customers (D/S2/T3.1)	179,187	182,277	
% Increase of Bills		1.7%	
% increase of customers		1.7%	
Customer Billing (\$K) (D/S2/T2)	\$523K	\$493K	\$517K
% increase (-decrease) in customer billing spending		-5.7%	
Cost per bill (\$/bill)			

Response

	2006 Actual	2007 Bridge	2008 Test
# bills	1,197,222	1,217,586	1,251,990
# customers	179,187	182,277	187,745
% increase in # bills	n/a	1.70%	2.83%
% increase in # customers	n/a	1.72%	3.00%
customer billing cost \$*	\$523,000	\$493,000	\$517,000
% increase (-decrease) in customer billing spending	n/a	-5.74%	4.87%
Cost per bill (\$/bill)	\$0.437	\$0.405	\$0.413

The variance in spending is due to staffing changes.

*Please note this captures the costs for one business unit only and not the total costs of Customer Service Department.

Interrogatory

#47. [Ref: D/2/5 and 6] Please confirm that the only costs that went down in 2007 and 2008 were “Usual Vacant Rate” of \$218,000 in 2008 and “Other” of \$38,000 in 2008. Please describe what these cost reductions were. Please provide the dollar figures for D/2/6.

Response

The usual vacant rate is a calculation based on an average of number of positions vacant by the average number of weeks the positions are vacant. The “Other” decrease in 2008 is caused by a decrease in some repair, maintenance and electrical expenses in 2008 over 2007.

Interrogatory

#48. [Ref: D/2/8.1] With respect to depreciation rates:

- a. Please file a copy of the Applicant's latest Depreciation Study.
- b. Please provide the depreciation rates used by the Applicant, for each of the categories listed on this Schedule, for each year from 2002 through 2007. Where any changes to depreciation rates have occurred during this period, please describe the quantum and reason for each such change.
- c. Please explain why Overhead & Underground Distribution Lines and Feeders have a 25 year life, when in C/5/1, p.40 the Applicant accepts that the normal life of such assets is 35 years. Please recalculate the 2008 Depreciation Expense on the assumption that the 35 year assumption is employed for that category of assets.
- d. Please explain why software is assumed to have a 2 year useful life.

Response

- a. Enersource has not performed a depreciation study. Enersource utilizes the amortization rates as set out in the OEB's 2006 Electricity Distribution Rate Handbook, Appendix B.
- b. Please refer to rate application Exhibit D/ Schedule 2/ Tab 8.1. There are no changes to depreciation rates during this period.
- c. Enersource utilizes the amortization rates as set out in the OEB's 2006 Electricity Distribution Rate Handbook, Appendix B.
- d. Operating software is depreciated over a 5 year term. "Out of the box" software is depreciated over a two year term, consistent with the treatment of CCA Class 45.

Interrogatory

#49. [Ref: G/2/5]

Please recalculate the chart in H/2/1 on the assumption: That no customer class would have a revenue to cost ratio of greater than 110%; and

- a. That no customer class would have a revenue to cost ratio of greater than 105%;
and**
- b. That all customer classes would have a revenue to cost ratio of 100%.**

Response

Enersource declines to provide the requested information on the grounds that the Cost Allocation Review – Informational Filing does not provide an adequate analytical tool to support the determination of cost responsibility.

Interrogatory

#50. Please explain why, with costs increasing, the Applicant has not proposed to increased its Other Regulated Charges to increase revenue from this source.

Response

Enersource has not proposed to increase its other regulated charges as these charges are aligned with the OEB standard charges authorized in the 2006 EDR process and are believed to appropriately inhibit bad customer behaviour.

Enersource is currently working with Board staff which has initiated a consultation process (EB-2007-0722) regarding issues associated with the provision of service by electricity distributors and the manner in which electricity distributors apply certain charges. The objective of this project is to develop, and codify where appropriate, Board policies relating to issues associated with the provision of service and application of charges by electricity distributors, with a view to ensuring consistent and fair treatment of electricity consumers across all electricity distributors. While this process is underway Enersource considers it premature to seek changes to other regulated charges.

SEC Interrogatories

Index of Attachments

1. #3 SEC 2006.pdf
2. #3 SEC 2008.pdf
3. #5 SEC EHM Strategic Plan Summary.pdf
4. #16 SEC.pdf
5. #24 SEC.pdf
6. #27 SEC System Capacity Report 2008.pdf
7. #28 SEC CIS Analysis.pdf
8. #28 SEC CIS Budget.pdf
9. #28 SEC CIS RFP Evaluation summary.pdf
10. #28 SEC Project Plan.pdf
11. #30 SEC Addendum #1-6.pdf
12. #30 SEC CIS RFP.pdf
13. #32 SEC Ex C Sch 3 Tab 2.pdf
14. #33a SEC.pdf
15. #33b SEC.pdf
16. #34 SEC Fleet budgets 2005 to 2008.pdf
17. #43 SEC.pdf

**ENERSOURCE CORPORATON
ORGANIZATION CHART
SUMMARY OF HEADCOUNT AS OF JULY 31, 06**

DIVISION	ENERSOURCE CORPORATION		ENERSOURCE HYDRO MISSISSAUGA		Total Active Union		Total Non Union		Total Vacant Union		Grand Total	
	CO.# 20		REGULATED CO. # 10									
	ACTIVE	VACANT	ACTIVE	VACANT	Inside	Outside	Active	Vacant	Inside	Outside	Active	Vacant
Executive	4	0	3	1	0	0	9	1	0	0	9	1
HR/ADMIN/SFT/COMM/COUNSEL	12	1			0	0	12	1	0	0	12	1
Finance	25	1			16	0	9	1	0	0	25	1
Rates & Reg. Affairs and Conservation			4	0	0	0	4	0	0	0	4	0
CD - Conservation			5	1	1	0	4	1	0	0	5	1
Customer Service & Billing Operations			61	4	37	11	13	3	1	0	61	4
Information Services			41	1	12	7	22	1	0	0	41	1
Distribution & Standards			65	5	5	52	8	0	1	4	65	5
Construction & Logistics			37	3	7	25	5	0	1	2	37	3
Customer Engineering			29	2	8	16	5	0	1	1	29	2
System Operations			31	2	2	20	9	1	0	2	31	3
System Planning			5	1	2	0	3	0	0	2	5	2
TOTAL	41	2	281	20	90	131	103	9	4	11	324	24

NU = 3 Active (exclude VP, and NW)
IN = 4 Active
OT = 11 Active

Total 18

11/12/07

**ENERSOURCE COPORATION
ORGANIZATION CHART
FORECASTED SUMMARY OF HEADCOUNT
AS OF JULY 2008**

DIVISION	ENERSOURCE CORPORATION		ENERSOURCE HYDRO MISSISSAUGA				Total Active Union		Total Non -Union		Total Vacant Union		Grand Total	
	CO.# 20		REGULATED CO. # 10											
	ACTIVE	VACANT	ACTIVE	VACANT			Inside	Outside	Active	Vacant	Inside	Outside	Active	Vacant
Executive	4		4				0	0	8	0	0	0	8	0
HR/ADMIN/SFT/COMM/COUNSEL	14						0	0	14	0	0	0	14	0
Finance	29						16	0	13	0	0	0	29	0
Rates & Reg. Affairs and Conservation			10				1	0	9	0	0	0	10	0
Customer Service & Billing Operations			77				42	12	23	0	0	0	77	0
Information Services			47				12	7	28	0	0	0	47	0
Distribution & Standards			76				7	61	8	0	0	0	76	0
Construction & Logistics			31				7	20	4	0	0	0	31	0
Customer Engineering			29				10	14	5	0	0	0	29	0
System Operations			41				2	28	11	0	0	0	41	0
System Planning			8				2	2	4	0	0	0	8	0
Enersource HM Services														
TOTAL	47	0	323	0			99	144	127	0	0	0	370	0

Note: Enersource has an average vacancy rate of 20 positions for an average of 10 weeks per year



ENERSOURCE HYDRO MISSISSAUGA

STRATEGIC PLAN SUMMARY

Prepared by: Roland Herman,
Executive Vice President & C.O.O.
December 2006



Strategy Overview

- To own, operate, build and maintain a growing electricity distribution business that performs to high operational standards of reliability, customer service, employee and community safety and cost effectiveness;
- Maximizes the economy of scale benefits of growth and achieves the size required to become one of the few expected large distribution companies to remain in Ontario;
- Earns a sustainable rate of return within the framework of a regulated environment and provides shareholders with consistent and predictable annual dividends.



Strategic Initiatives

- Capital Restructuring
- Organizational Restructuring
- Regulatory/OEB Focus
- Culture Shift
- Growth/Mergers/Acquisitions
- Operational Excellence
- Special Projects

Answers to SEC question 16 B

Facilities and Information Systems Recoveries: Received from Enersource Corporation and Hydro Mississauga Services

	2008 Test Yr	2007 Bridge Yr	2006 Actual	2005 Actual
Facilities costs to Enersource Hydro Mississauga	\$ 1,948	\$ 1,785	\$ 1,539	\$ 1,369
Information Systems costs to Enersource Hydro Mississauga	\$ 3,067	\$ 2,838	\$ 2,139	\$ 1,928

Driver

HEADCOUNT:

Enersource Hydro Mississauga	323	317	279	276
Enersource Telecom	-	-	-	15
Enersource Corporation	47	47	41	40
Enersource Hydro Mississauga Services	20	15	17	10
	390	379	337	341

Facilities Costs Recoveries Allocated to Affiliates	\$ 335	\$ 292	\$ 265	\$ 261

Information Systems Costs Recoveries Allocated to Affiliates	\$ 527	\$ 464	\$ 368	\$ 368

Return on Assets: Received from Enersource Corporation and Hydro Mississauga Services

	2008 Test Yr	2007 Bridge Yr	2006 Actual	2005 Actual
	CO#10	CO#10	CO#10	CO#10
Assets values to be allocated	27,935	18,356	16,083	20,766

Driver

HEADCOUNT:

Enersource Hydro Mississauga	323	317	279	276
Enersource Telecom	-	-	-	15
Enersource Corporation	47	47	41	40
Enersource Hydro Mississauga Services	20	15	17	10
	390	379	337	341

Total Return/Markup Recovered from Affiliates	\$358	\$224	\$166	\$261

ENERSOURCE HYDRO MISSISSAUGA**2008 BUDGET****CAPITAL EXPENDITURES**

Enersource Hydro Mississauga Inc.

EB-2007-0706

2008 Electricity Distribution Rates Application

Filed: November 12, 2007

Exhibit C

Schedule 3

Tab xxx

Note: all amounts in \$000'S

CATEGORY	2007	2006
	Bridge Year	Historic Actual
Integrated Operating Model	1,200,000	-
SCADA upgrade	250,000	867,496
Engineering Document Management Software	650,000	-
Hardware	695,000	1,126,890
JDE Upgrade	-	133,823
Mainframe Upgrade	-	266,013
Software	687,000	458,498
Photocopier Upgrade	-	96,112
CIS	4,000,000	89,105
CIS Fieldworker Integration	-	36,812
People Soft HR Implementation	-	4,717
	7,482,000	3,079,467

SEC#27



System Capacity Report

2008

SYSTEM PLANNING DEPARTMENT

Version 2.0
October 5, 2007

DOCUMENT ACCEPTANCE and RELEASE NOTICE

This is version 2.0 of the System Capacity Report 2008.

The System Capacity Report is a managed document. For identification of amendments each page contains a release number and a page number. Changes will only be issued as a complete replacement document. Recipients should remove superseded versions from circulation. This document is authorised for release once all signatures have been obtained.

PREPARED: _____ DATE: ____/____/____
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ACCEPTED: _____ DATE: ____/____/____
(for review) (Paul Sidhu, P.Eng,)

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1. Executive Summary

The Enersource Hydro Mississauga (EHM) System Capacity Report provides a discussion of EHM's anticipated capital developments for the year 2008. The projects that are recommended in this report are related to the reinforcement of a number of areas in the City of Mississauga.

Significant growth has occurred in a number of new housing, industrial and commercial service developments over the last three years. Extensive industrial development is continuing to occur within the North 27.6kV system and this trend is expected to continue over the next three to five years. A major water and waste water treatment plant (26MW) is expected to be fully operational by 2008 and will be fed by the South 27.6kV system. The 44kV system continues to serve predominantly residential and commercial loads and will be further stressed by significant residential loads that are planned and under construction in the western and central portion of the city over the next 2 to 3 years. It is projected that an additional 30MW will be added to the EHM grid in these areas in the next two years. It is clear that EHM's system will have to be expanded in the medium term, to effectively and reliably serve its customers.

The year to-date system peak for 2006 was 1610 MW on August 1st 2006. This system peak, has surpassed our previous system peak record of 1570 MW set back in July 2005, an increase of 2.55%. The Enersource Hydro Mississauga system peak is almost entirely weather driven, and the summer of 2006 marked some of the hottest stretches of days in recent history.

The summer of 2005 overall was much hotter overall than the summer of 2006; this was seen with improved reliability numbers for 2006 compared to 2005. EHM customers experienced an average of 27.2 minutes of power interruption for 2006; which is a decrease of 4.5 minutes (14.2%) from 2005.

2. Introduction

Electrical power in the City of Mississauga originates from 10 Hydro One Transformer Stations (TS). The power is transformed at these TS's from 230 kV down for municipal use to subtransmission voltages of 44 kV and 27.6 kV and to primary distribution voltage of 16.0/27.6 kV. The subtransmission voltages of 44 kV and 27.6 kV are further transformed at the Municipal Substations (MS) owned by Enersource Hydro Mississauga, to primary distribution voltages of 8.0/13.8 kV and 2.4/4.16 kV.

The prime study area (see Figure 2A) identified in the report is broken down into six study regions:

- Meadowvale 44/13.8
- Erindale 44/13.8
- Tomken 44/13.8
- Bramalea-Woodbridge 44/13.8
- North 27.6
- South 27.6/4.16

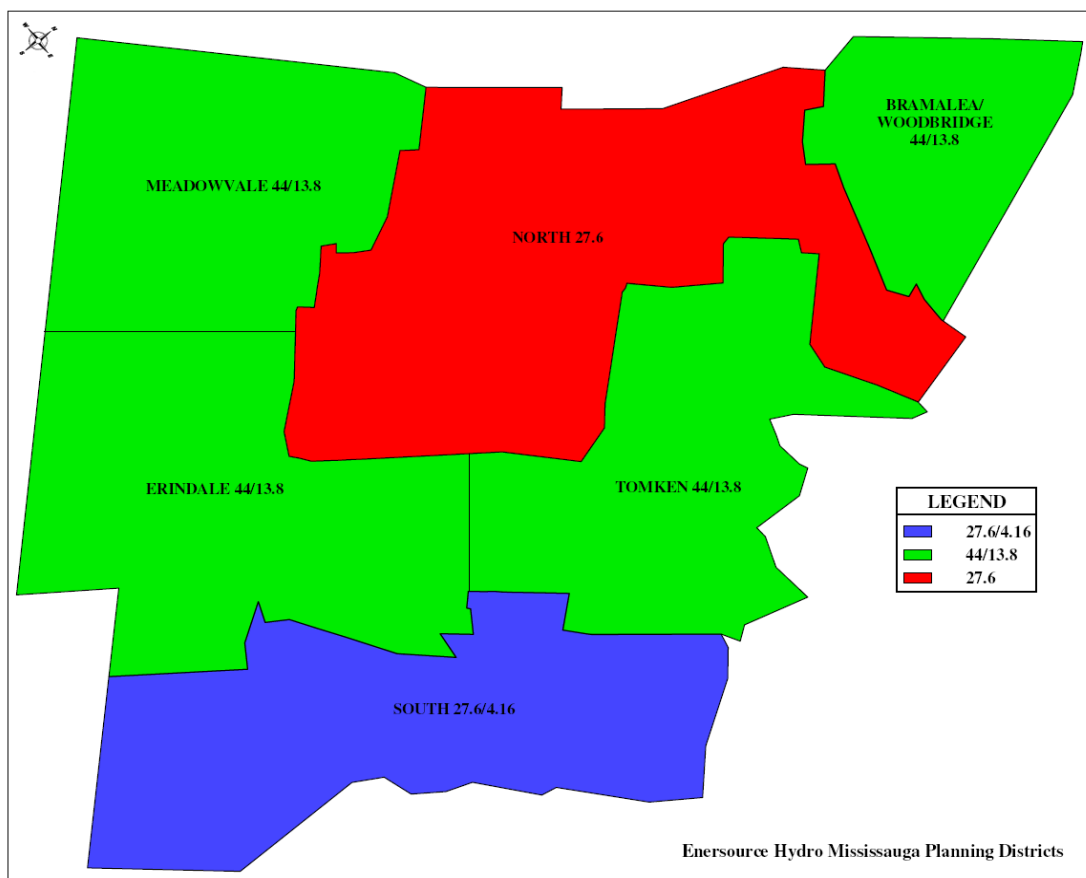


Figure 2A

3. Definition of EHM's Facilities

3.1. Subtransmission Facilities

The subtransmission system consists of power lines that take electrical energy from the transformer stations and delivers it directly to larger customers, or to substations where it is transformed for delivery onto the EHM distribution system. EHM's subtransmission system is comprised of the following:

3.1.1. 44 kV Subtransmission

- Delivery points include Meadowvale TS, Erindale TS, Tomken TS, Bramalea TS and Woodbridge TS.
- 47 operational supply feeders with a total capacity of 1645 MVA.
- 2 possible feeders from Meadowvale (requires bus extension) with a capacity potential of 70MVA.
- 2 express feeders are for export of generation (Trans Alta at Bramalea TS).
- 33 industrial/ commercial customers directly connected with 80 customer owned power transformers.
- 1405 km of 44kV power lines.

3.1.2. 27.6 kV Subtransmission

- Delivery points include Cooksville TS, Lorne Park TS and Oakville TS.
- 26 operational supply feeders with a total capacity of 572 MVA.
- 767 km of 27.6kV power lines.
- 285 customers directly connected (269 industrial/ commercial & 16 residential) with 163 customer owned power transformers.
- 2 express feeders for St. Lawrence Cement
- 2 express feeders for Petro Canada

3.2. Distribution Facilities

The distribution system delivers electrical energy from EHM's substations to the majority of EHM's customers. The EHM distribution system consists of the following:

3.2.1. 16.0/27.6 kV Distribution

- Delivery points are Erindale TS, Bramalea TS, Richview TS and Cardiff TS.
- 32 operational supply feeders with a total capacity of 704 MVA.
- 40,063 customers connected (4,389 industrial/ commercial & 35,674 residential).
- 2778 km of 16.0/27.6 kV power lines.
- 5,953 transformers connected (164 of these are customer owned and the rest EHM).

3.2.2. 8.0/13.8 kV Distribution

- 40 municipal stations comprised of 62 step-down transformers rated 13.8/44 kV.
- 193 operational feeders with a total capacity of 1544 MVA.
- 115,742 customers connected (13,974 industrial/ commercial & 101,768 residential).
- 5,401 km of 8.0/ 13.8kV power lines.
- 15,675 transformers connected.

3.2.3. 2.4/4.16 kV Distribution

- 26 municipal substations comprised of 34 step-down transformers rated 4.16/27.6 kV.
- 103 operational feeders with a total capacity of 247 MVA.
- 28,248 customers connected (2,159 industrial/ commercial & 26,089 residential).
- 1,135 km of 2.4/4.16 kV power lines.
- 3,822 transformers connected.

4. Major Drivers for Facilities Requirement

Additions to the EHM system are normally required because of an expected violation of EHM's performance criteria. Violation of system adequacy, in particular the ability to maintain satisfactory power capacity and voltage levels, are the performance criteria that most often drives requirements for new facilities. EHM checks for violations of its performance criteria. Violations of the performance criteria predicted by the models usually results from forecast increases in power flow over the subtransmission or distribution facilities. Also, aging infrastructure (Reliability) is another factor, which is unrelated to increased power transfers, but may result in a requirement for new or upgrade of facilities.

The major drivers contributing to the need for new or upgrade of facilities include:

- Demand Forecast
- Connection of future new large customers
- Load Duration Curves
- Reliability Performance

4.1. EHM Long Term Demand Forecast

Peak demand has averaged an annual compounded growth of 4.62% over the 2000 to 2006 time frame. Demand growth is a function of the level of weather factors, economic activity, the rate of population growth and the increase in the number of housing units. The City of Mississauga economy has expanded consistently since the year 2000, with the population growing by 40,000 people, also nearly 55,000 new jobs were added and more than 20,000 housing units built.

The forecasting system adapted uses econometric equations to estimate the relationships between peak demand and a number of analytical factors or drivers. The drivers that the system includes are weather effects, economic data, calendar variables, and demand response programs. Using regression techniques, the model estimates the relationship between these drivers and peak demand.

For the purpose of this analysis the weather is not forecasted but instead two scenarios are considered. Normal weather and extreme weather are used to forecast peak demand. The normal weather is the average temperature values of a 35-year history (1972-2006). For the Extreme weather scenario, the historical data used was from the year 2002 which was ranked as one of the highest extreme weather years in history.

Normal weather forecasted (see Table 4A) results for peak demand show an average annual growth rate of 0.5%. This low growth rate indicates the effect of normal temperatures and the eventual maturing of the City of Mississauga in the next 25 years. As the City of Mississauga makes the transition from a fast growing municipality to a mature urban community, the rate of growth of peak demand will decline steadily over the forecast period.

Forecasted Annual Peak Demand (MW)								
2007	2008	2009	2010	2011	2016	2021	2026	2031
1512	1531	1549	1567	1582	1631	1660	1681	1699
-6.09 %	1.26 %	1.18 %	1.16 %	0.96 %	3.10 %	1.78 %	1.27 %	1.07 %

Table 4A – Forecasted Annual Peak Demand (Normal Weather)

For system expansion process, the load forecast results using the extreme weather scenario would be used as the basis to develop strategies to expand the EHM distribution network at the least cost. The reason being is that peak demand occurs over a short time period (hours) and statistically, the likelihood of short extreme weather conditions occurring during the year is high. Table 4B shows the 25 year forecasted annual peak demand for extreme weather temperatures.

Forecasted Annual Peak Demand (MW)								
2007	2008	2009	2010	2011	2016	2021	2026	2031
1635	1666	1685	1703	1717	1766	1795	1816	1834
1.55 %	1.90 %	1.14 %	1.07 %	0.82 %	2.85 %	1.64 %	1.17 %	0.99 %

Table 4B – Forecasted Annual Peak Demand (Extreme Weather)

In summary, the City of Mississauga in the next 5-10 years will have their availability of land supply evaporate. However, modest growth will be maintained as re-development in the City will continue with high density housing being the major economic factor that drives growth in peak demand. The overall load forecast clearly shows the steady decline in load growth for the next 25 years.

Refer to Supporting Document A – EHM Long Term Demand Forecast 2007-2031 for detailed information on EHM demand forecast.

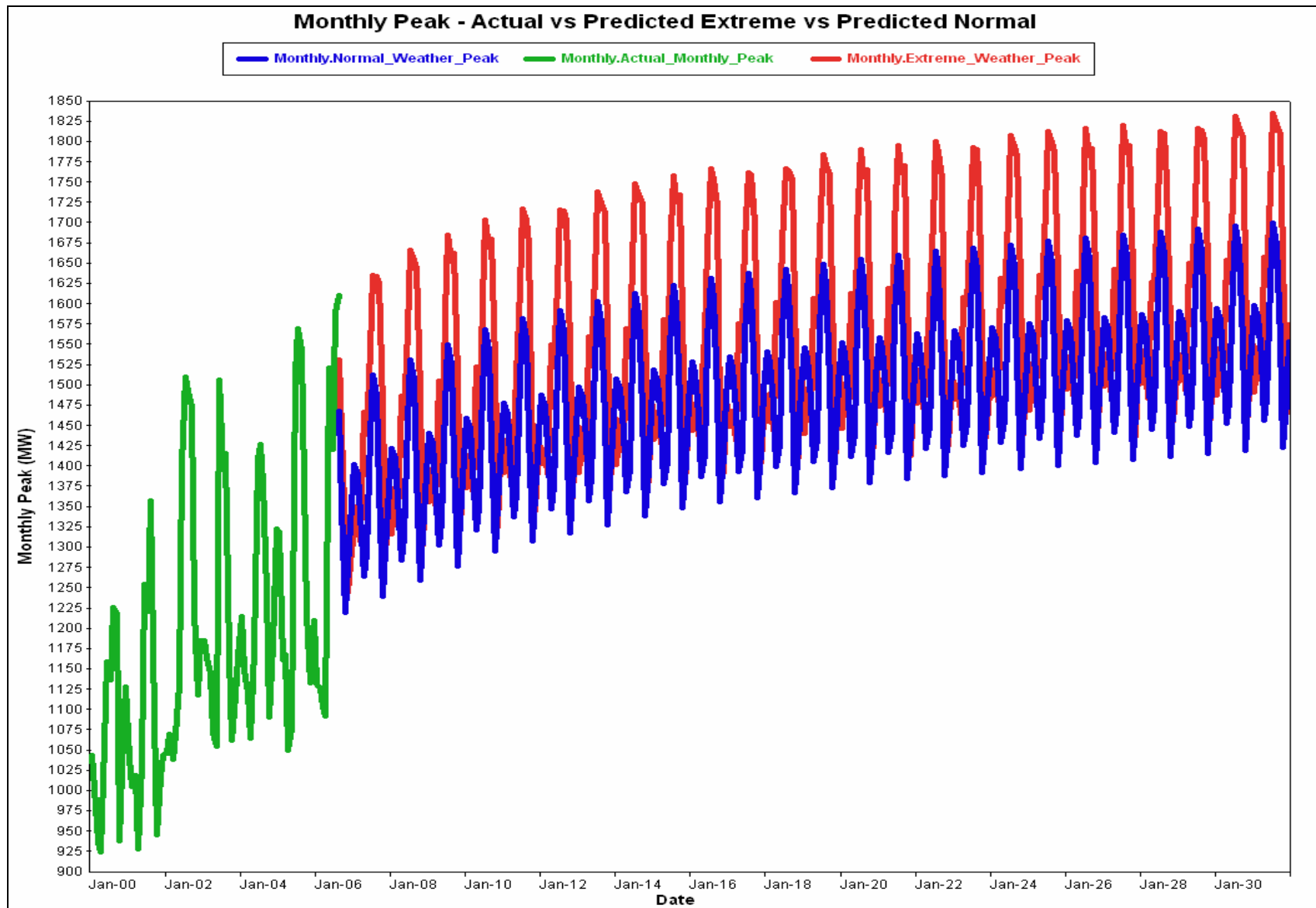


Figure 4A –Monthly Peak 2000-2031: Actual vs Extreme Forecast vs Normal Forecast

4.2. Connection of New Major Load

Significant growth has occurred in a number of new housing, industrial and commercial service developments over the last three years. Extensive industrial development is continuing to occur within the North 27.6kV system and this trend is expected to continue over the next three to five years. A major water and waste water treatment plant (26MW) is expected to be fully operational by 2008 and will be fed by the South 27.6kV system. The 44kV system continues to serve predominantly residential and commercial loads and will be further stressed by significant residential loads that are planned and under construction in the western and central portion of the city over the next 2 to 3 years. It is projected that an additional 30MW will be added to the EHM grid in these areas in the next two years. It is clear that EHM's system will have to be expanded in the medium term, to effectively and reliably serve its customers.

4.3. Load Duration Curves

Load duration curves were developed (see supporting document named "Load Duration Curves" dated August 2006), for 368 feeders and 103 station transformers (monitored by SCADA) for the year or 365 days x 24 hours = 8760 hours which is the x- axis. The feeders should not exceed 1.00 per unit at any given time because this indicates that the feeders have run beyond their operating specifications.

Example:

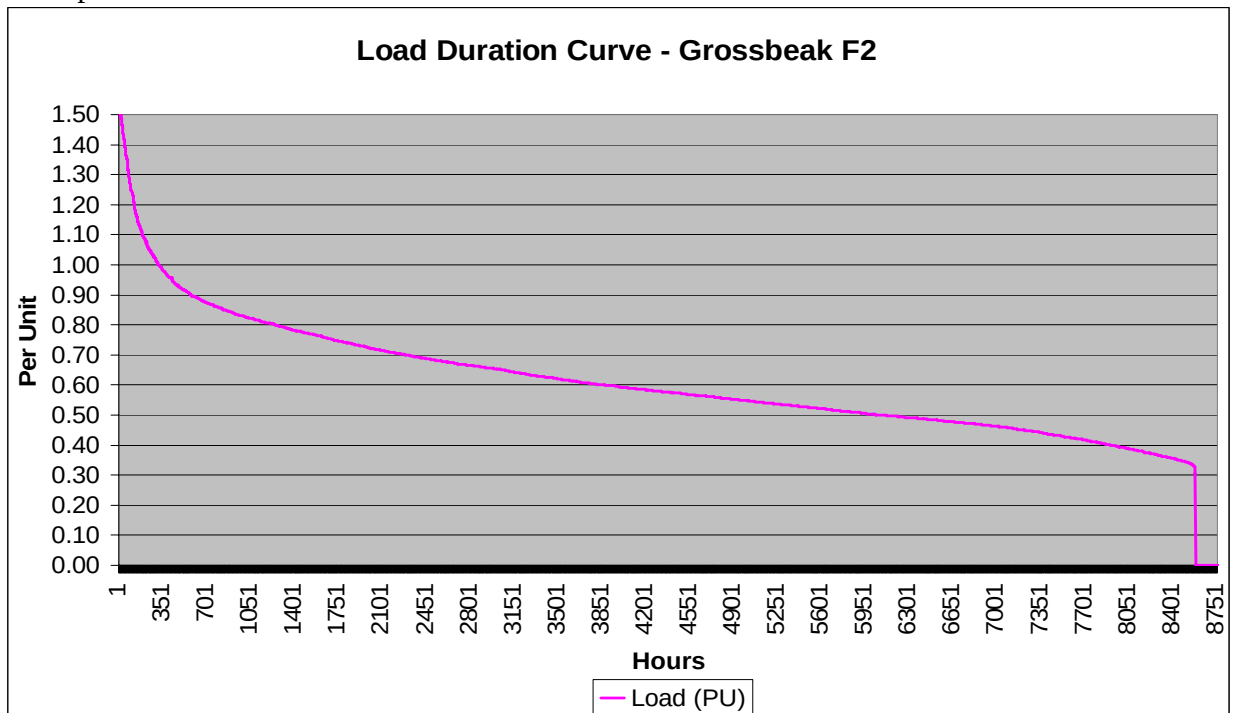


Figure 4B

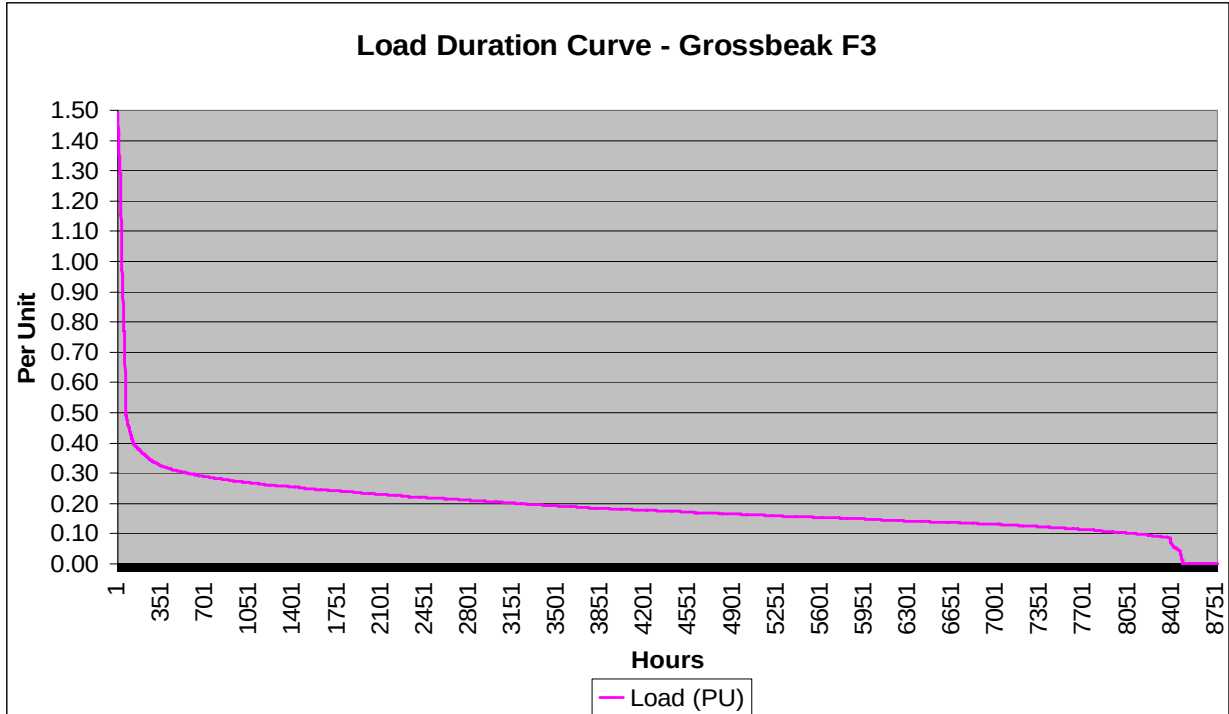


Figure 4C

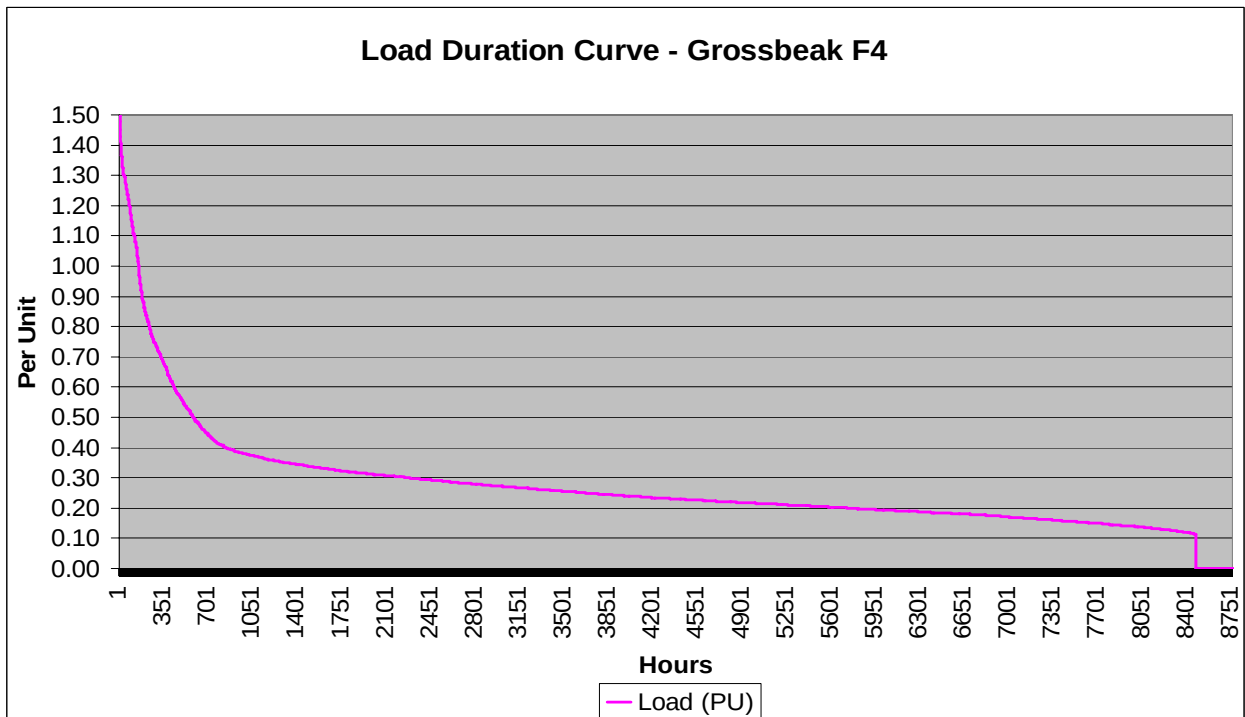


Figure 4D

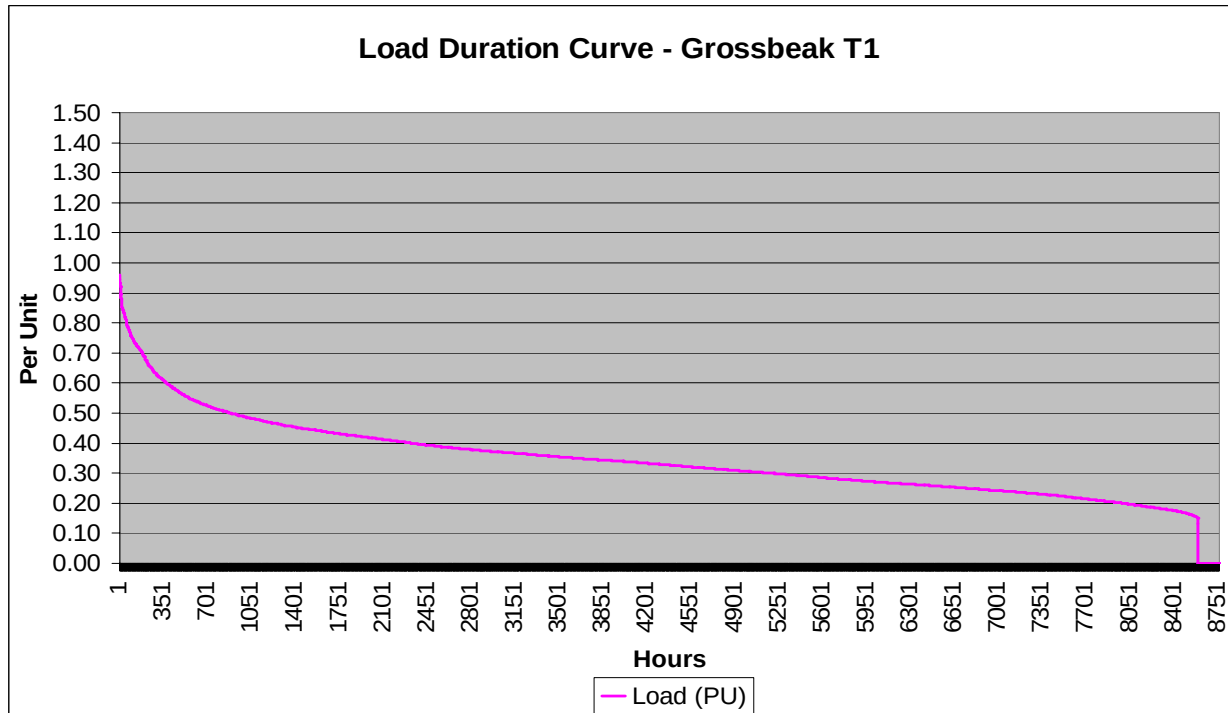


Figure 4E

The load duration curves will be used to identify prolonged or abnormal loading conditions for the feeders and transformers at the stations. This in combination with the reliability data discussed in section 4.5 of this document will be used to identify areas on the EHM system that require immediate attention.

Ideally the feeder curves should not exceed 1.00 per unit. When the curves exceed 1.00 per unit this indicates that the feeders for that time period are being overloaded and are exceeding the cable ampacity ratings. The curves shown in Figures 4B to 4E for Grossbeak MS indicate that several of the feeders often exceed their cable ratings by as much as 150% or 1.50 per unit. This type of prolonged loading can lead to early failure of the cables. It can also be seen that during coincident peak the transformer T1 is already close to the 100% maximum rating (33MVA). With known data that the area which Grossbeak MS serves is experiencing further growth it has been recommended for projects in 2007 that a second 20/33 MVA transformer be added to Grossbeak MS.

4.4. Reliability Performance

System reliability for 2006 marked a significant improvement from 2005 in terms of average customer minutes lost per customer. This is mainly due to the fact that the heat wave of 2006 was limited to several days as compared to the sustained stress on the

system during the heat wave of 2005. Our customers experienced an average of 27.2 minutes of power interruption for 2006; this is a decrease of 4.5 minutes (14.5%) from 2005 (refer to Table 4C).

TOTAL INTERRUPTIONS					
	2006	2005	2004	2003	2002
INTERRUPTIONS	451	484	430	432	496
CUSTOMERS AFFECTED	132,000	166,000	109,000	130,000	108,000
CUSTOMER MINUTES	4,892,000	5,637,000	3,875,000	4,017,000	3,925,000
SAIDI (Minutes)	27.2	31.7	22.1	23.4	23.6
CAIDI (Minutes)	37.1	34.2	35.5	30.8	36.5
SAIFI	0.73	0.93	0.62	0.76	0.65
SAIFI (MI)	3.80	3.40	1.6	2.1	2.0

Table 4C

Cable and splice failures are still the main causes of customer outages (please refer to Figure 4F). Enersource Hydro Mississauga's system continues to age and it is clear that cable replacement must be continued. A detailed review of the performance of individual system components was undertaken as part of this report. This included analysis of loading, line losses and reliability of substations and feeders.

To supply the increasing load and maintain the required system efficiency and reliability, a number of system expansion and rebuild projects are proposed for 2008 to 2010.

In addition, the plan recommends continuation of projects such as remote monitoring of the system, automation as well as upgrading to new RTUs and a new frequency band will allow for accurate loading measurement on system components and faster switching for power restoration during outages. This will improve our ability to increase the loading of the power-carrying components of the electrical distribution network and reduce the need of future construction of additional redundancy in the system.

A number of projects relating to system upgrade, including transformer replacement, overhead distribution upgrade and underground distribution upgrade are also included.

Refer to Supporting Document C - EHM 2006 Year End Reliability Report for detailed information on EHM system reliability for year ending 2006.

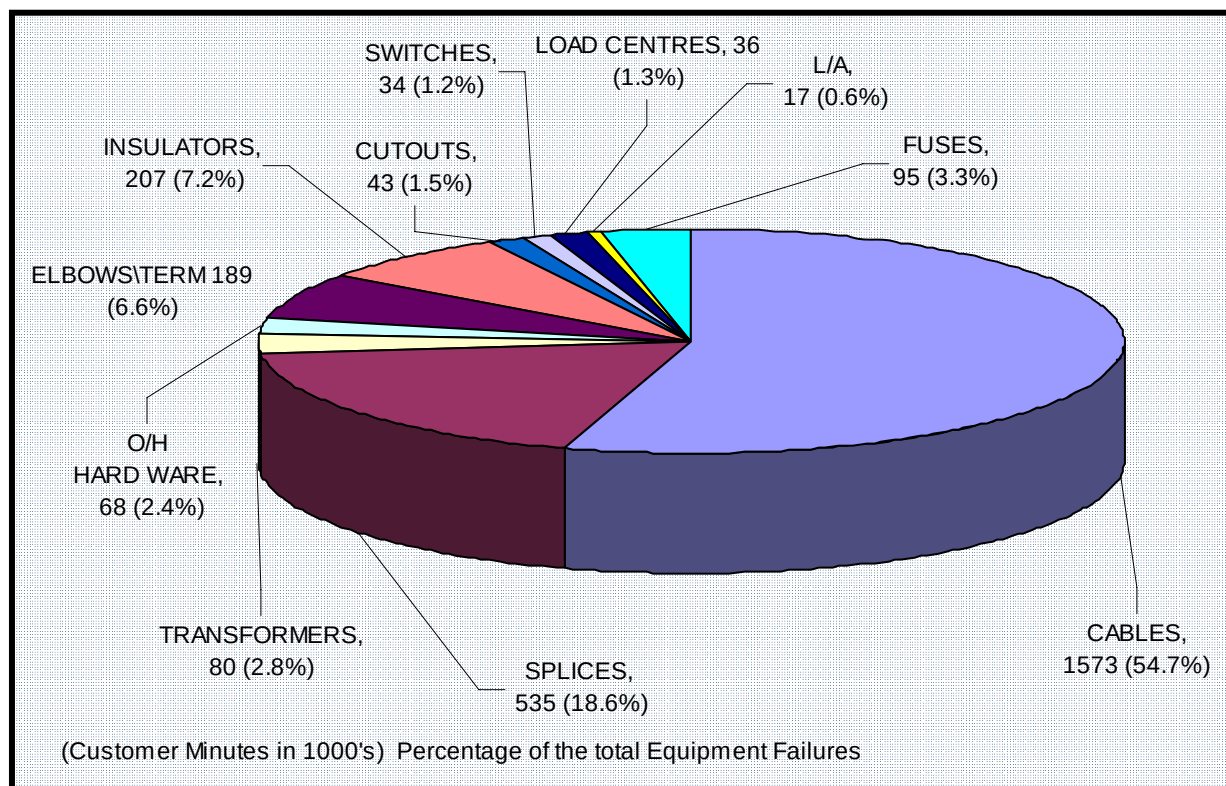


Figure 4F – Equipment Failures

5. Facilities Investment Management

EHM's distribution business aims to continuously improve the capability and performance of the regulated wires assets. This involves facilities investment management processes and practices to ensure that facility related decisions are rational, adequate and economically viable. These decisions are used to help develop logical and prioritized projects for the addition, upgrading, operation and maintenance of EHM facilities.

5.1. Methods of Analyzing Facilities Investment

Facilities and their components are subject to deterioration that will eventually impede their ability to function as originally designed. Facility deterioration depends on factors such as geographic location, utilization, age, weather and maintenance practices. The deterioration process typically manifests itself by a decline in equipment performance reliability, increased environmental risks, and an increase in potential safety hazards to both the public and employees. Ultimately, facilities deteriorate to the point that they are no longer able to perform their function in a cost-effective manner, at which point replacement becomes necessary rather than continue to repair or maintain.

The following are methods, processes and practices used to help analyze EHM facilities investments:

5.1.1. System Performance

A detailed review of the performance of individual system components was undertaken. This included analysis of loading, line loss and reliability of the subtransmission feeders, substation transformers and primary feeders.

In addition, a district planning load forecast, based on site plan approvals, building permits, subdivision construction and commercial/industrial service applications, were developed.

For each of the feeders, the following items were used or computed:

- Operator monitoring and experience (daily operator report)
- Reliability performance based on indices which measure the average duration and frequency of outages, were calculated between July 2005 and July 2006.

Analysis of these feeders was performed and methods to overcome the exposure were identified. These methods included measuring the extent of feeder loading, reviewing and expanding maintenance programs and finally the need for new system capital projects.

5.1.2. *Cost Benefit Analysis*

The benefits identified include:

- Additional MW capacity
- Savings to the community due to savings in Customer-minutes and Effective MW minutes of outages
- Projected revenue due to the ability to serve new and existing customers by expanding the network

5.1.3. *Facilities Life Cycle Planning*

The strategy that EHM uses to help manage facilities investments is the Facilities Life Cycle planning approach, see Figure 5A, which aims at optimizing performance and cost over the service life of facilities.

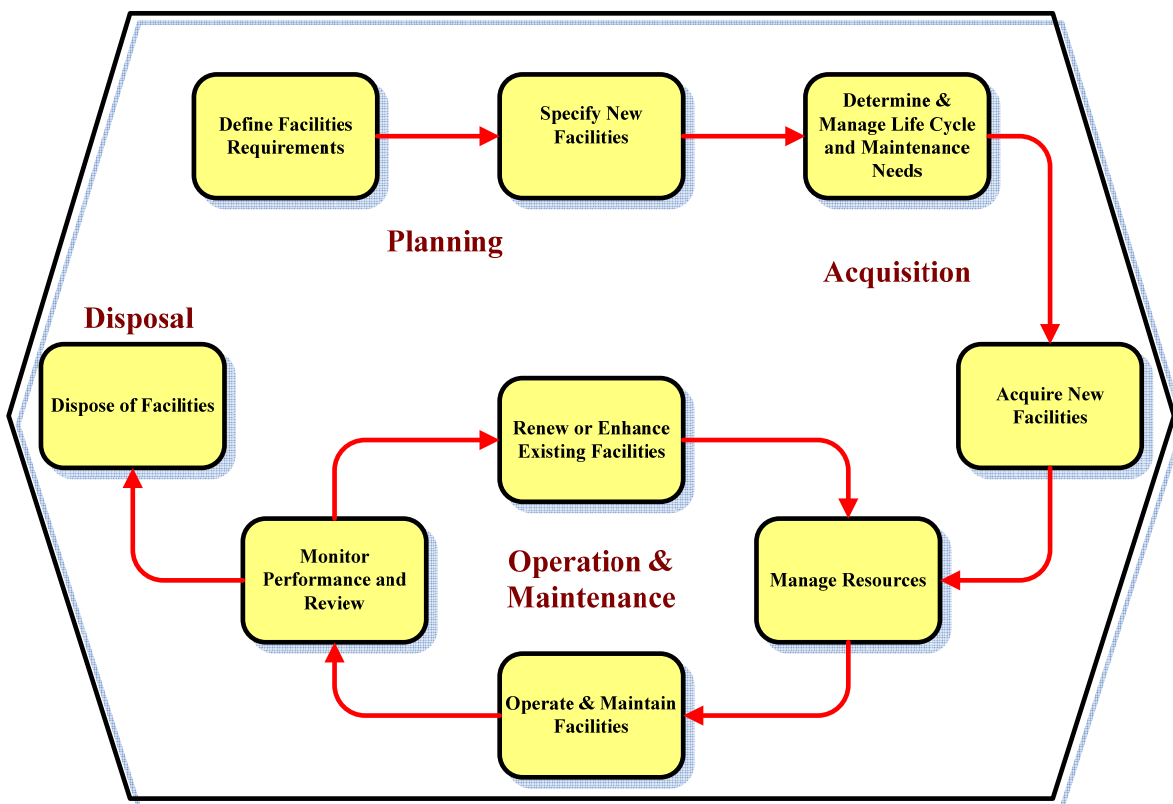


Figure 5A – Facilities Life Cycle Planning

5.1.4. Reliability Measures

The cost of outages to the community is calculated based on the results developed from customer surveys, analytic methods, and actual interruption or case study methods. The results are shown in the following table:

Interruption Cost Models*		
	Duration of Outage	Average Cost \$/kW
Residential Model 1	60 minutes	1.77
Residential Model 2	4 hours	7.08
Commercial Model 1	1 minute	0.47
Commercial Model 2	20 minutes	2.80
Commercial Model 3	8 hours	113.10
Industrial Model 1	1 minute	1.30
Industrial Model 2	20 minutes	4.18
Industrial Model 3	8 hours	42.0

*Based on Surveys and studies as reported to EDA, EPRI and US Department of Energy.

Table 5A

Based on the above values, the savings to the community is conservatively estimated at \$5 per customer-minute of reduction in the power outage.

5.1.5. Risk Assessment & Project Prioritization

The lists of detailed projects that are developed are consistent with the major drivers for facilities discussed in Section 4 of this report. Each specific project is evaluated against certain business values; see Table 5B, to identify associated risks of not conducting the work. Risk assessment is conducted on projects to help develop solutions to mitigate these risks. For each projects a prioritization index (cost versus benefit) is developed and all projects are then prioritized.

Business Value	Key Success Factor	Key Performance Indicator	Weighting
Customer	Improve overall customer satisfaction	Customer satisfaction survey	25 %
Health & Safety	Keep our people, service providers and the public safe	- Employee Safety - Service Provider safety - Public Safety	25 %
Legal/ Regulatory & Environmental Compliance	Meet all compliance Standards	- Regulatory SQI Index - Legal Violations - License conditions	25 %
Reliability & Long Term Sustainability	Improve long term reliability of the Subtransmission and distribution systems	- Unsupplied power - SAIDI - Worst served customers	25 %

Table 5B

The prioritization process converts the business values and key performance indicators in Table 5B into investment criteria and guidelines that are used for managing risk and facilitating trade-offs between facilities investments.

5.2. Facilities Investment Categories & Budgets

In organizing and planning projects, EHM has five main facilities investment categories for projects; System Capacity – Growth Driven Investment; System Maintenance – Reliability Driven Investment; System Expansion & Upgrades – Customer Driven Investment; Non-System Requirements – Regulatory Driven Investment; and Non-System Requirements – Internally Driven Investment. Each of these categories can have a Capital and/or OM&A component.

EHM’s capital programs, historical and proposed budget levels are described below:

5.2.1. System Capacity – Growth Driven Investment

The capital projects for System Capacity – Growth Driven Investments are to ensure that EHM’s capability to provide a secure and reliable supply of electrical energy in response to cumulative system wide load growth demands. Growth is predicted through the combined use of load-forecast models, historical growth patterns, and specific load measurements taken at times of heavy loading during the summer.

Projects for the System Capacity – Growth Driven Investments are designed to increase the capability of existing EHM lines and substations, or to construct new EHM lines and substations in response to system growth forecasts.

The proposed funding of capital projects for System Capacity – Growth Driven Investments and their spending levels for the bridge and historic years are provided in Table 5C below:

(\$ Millions)

Description	Historic				Bridge	Forecast		
	2003	2004	2005	2006	2007	2008	2009	2010
Subtransmission/Distribution Lines Construction	3.86	5.16	5.74	4.83	5.85	5.85		
Substation Construction	2.63	2.73	2.84	3.31	2.88	3.43		
Total	6.50	7.89	8.58	8.14	8.73	9.28		

Table 5C- Capital Budget: System Capacity – Growth Driven Investments

5.2.2. **System Maintenance – Reliability Driven Investment**

System Maintenance – Reliability Driven Investments are defined as projects required for maintaining the existing infrastructure and facilities at their required performance level.

The capital component of the System Maintenance – Reliability Driven Investment projects deal with replacement of assets at end of life, i.e. transformer replacements, subdivision rebuilds and pole replacements. The OM&A component of the sustainment work addresses preventative and breakdown (corrective) maintenance within the useful life-span of the equipment, i.e. underground distribution maintenance, overhead distribution upgrades and refurbish/upgrade data acquisition systems, including automatic system controls, which monitor and control the operation of the EHM system.

The proposed funding of capital projects for System Maintenance – Reliability Driven Investments and their spending levels for the bridge and historic years are provided in Table 5D below:

(\$ Millions)

Description	Historic				Bridge	Forecast		
	2003	2004	2005	2006	2007	2008	2009	2010
Subdivision Rebuilds	2.00	1.75	4.12	4.28	5.95	6.10		
Overhead Distribution Upgrades	3.48	2.56	1.71	2.99	2.53	2.60		
Underground Distribution Maintenance	2.61	2.26	1.74	2.30	2.13	2.20		
Transformer Replacement	0.70	0.73	0.60	0.89	0.60	0.65		
P&C and SCADA Upgrades	1.33	0.78	1.19	1.55	1.37	1.40		
Total	10.11	8.07	9.36	12.00	12.57	12.95		

Table 5D - Capital Budget: System Maintenance – Reliability Driven Investments

5.2.3. **System Expansion & Upgrades – Customer Driven Investment**

System Expansion & Upgrades – Customer Driven Investments are defined as projects required to connect new customers or to modify customers' present service. Projects of this nature are not discretionary, but mandatory, and include work such as new residential/commercial/industrial services, city or region road relocation projects and new/upgrade metering equipment. The proposed funding of capital projects for System Expansion & Upgrades – Customer Driven Investments and their spending levels for the bridge and historic years are provided in Table 5E below:

(\$ Millions)

Description	Historic				Bridge	Forecast		
	2003	2004	2005	2006	2007	2008	2009	2010
New Industrial/Commercial Customer Services	3.50	6.63	6.09	6.91	4.00	4.20		
New Subdivisions	-	-	-	-	2.50	2.58		
Road Projects	0.25	0.55	0.92	0.51	0.75	0.75		
Metering Equipment	0.75	1.24	1.07	1.11	0.84	0.89		
Total	4.50	8.42	8.08	8.52	8.09	8.42		

Table 5E - Capital Budget: System Expansion & Upgrades – Customer Driven Investments

5.2.4. Non-System Requirements – Regulatory Driven Investment

Non-System Requirements – Regulatory Driven Investments are defined as projects which are mandated by electricity regulations. Projects of this nature include wholesale metering upgrades per IESO market rules and OEB sponsored initiatives such as smart metering and conservation/demand response programs. The proposed funding of capital projects for Non-System Requirements – Regulatory Driven Investments and their spending levels for the bridge and historic years are provided in Table 5F below:

(\$ Millions)

Description	Historic				Bridge	Forecast		
	2003	2004	2005	2006	2007	2008	2009	2010
Conservation & Demand Response	-	-	1.15	1.88	0.30	-		
Wholesale Metering	-	-	0.18	0.15	0.28	0.15		
Smart Metering	-	-	-	0.21	9.23	0.98		
Total	-	-	1.33	2.24	9.81			

Table 5F - Capital Budget: Non-System Requirements – Regulatory Driven Investments

5.2.5. Non-System Requirements – Internally Driven Investment

Non-System Requirements – Internally Driven Investments are defined as projects required to enhance, refurbish and replace computer management systems, major tools, building facilities, fleet, information systems and engineering & asset systems. The proposed funding of capital projects for Non-System Requirements – Internally Driven Investments and their spending levels for the bridge and historic years are provided in Table 5G below:

(\$ Millions)

Description	Historic				Bridge	Forecast		
	2003	2004	2005	2006	2007	2008	2009	2010
CIS	-	-	-	-	4.00	6.54		
Rolling Stock	0.08	2.36	1.82	1.62	1.86	1.86		
Major Tools	0.11	0.15	0.20	0.14	0.15	0.15		
Information Technology	1.89	1.32	1.01	1.04	1.09	.72		
Engineering & Asset Systems	1.39	0.66	0.48	2.04	2.40	1.55		
Grounds & Buildings	0.26	1.06	1.60	0.99	2.11	4.65		
Total	3.73	5.54	5.11	5.83	11.60	15.47		

Table 5G - Capital Budget: Non-System Requirements – Internally Driven Investments

6. Recommendations

SUMMARY

Enersource Hydro Mississauga has prepared the System Capacity Report for 2008. A copy of this report is included in this agenda.

The report indicates which additional system capital projects are required to maintain system reliability at an acceptable level and to accommodate increased load on the system.

RECOMMENDATIONS (Resolution)

See Resolution attached.

7. References & Supporting Documents

- 1. A – EHM Load Term Demand Forecast 2007-2031**
- 2. B – EHM Load Duration Curves**
- 3. C – EHM 2006 Year End Reliability Report**
- 4. E – EHM Project Business Cases 2008**

COST COMPARISON FOR RFP EC2006-008

	SPL 2 EHM	SPL 2 EHM & TH 50/50 Split	SPL 2 EHM & TH Notes	SPL 3 EHM	SPL 3 EHM & TH 50/50 Split	IBM 1 Group	Siemens 1 EHM	Siemens 1 EHM & TH 50/50 Split	Siemens 2 EHM	Siemens 2 EHM & TH 50/50 Split	Siemens 3 EHM	Siemens 3 EHM & TH 50/50 Split	Accenture 1 EHM & TH 50/50 Split	Accenture 1 EHM & TH Notes	corrected accenture values
License	1,118,520	719,031	Sec7 P195	1,118,520	719,031	593,911	1,117,800	1,117,800	1,117,800	1,117,800	1,117,800	1,117,800	2,279,644	Sec5 P5-5	1102612.5
Travel	784,253	529,068	Sec7 P208	784,253	529,068	762,197	428,609	214,305	428,609	214,305	428,609	214,305	1,141,580	Sec5 P5-5	
Training	199,496	154,776	Sec7 P209	199,496	154,776	418,724	72,050	36,025	72,050	36,025	72,050	36,025			
Project Management	424,496	293,166	Sec7 P209	424,496	293,166	658,687	479,360	479,360	479,360	479,360	479,360	479,360			
Customization	1,542,001	1,009,123	Sec7 P210	1,542,001	1,009,123	5,700,000	1,168,300	584,150	1,168,300	584,150	1,168,300	584,150			
Implementation	1,760,560	1,205,598	Sec7 P210	1,760,560	1,205,598		3,384,875	3,384,875	3,384,875	3,384,875	3,384,875	3,384,875	7,610,532	Sec5 P5-5	
Transition Fee						1,056,000	254,360	254,360							
Hardware	1,000,000	1,000,000	Rod Lee	1,000,000	1,000,000				1,000,000	1,000,000	1,000,000	1,000,000			
Internal Costs of Implementation	1,000,000	1,000,000	10 people for 1 yr	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	10 people for 1 yr	
Contingency	1,000,000	1,000,000		1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000		11,854,725
Total Implementation Costs	8,829,326	6,910,761		8,829,326	6,910,761	11,189,518	8,905,354	8,070,875	9,650,994	8,816,515	9,650,994	8,816,515	13,031,756		
Annual Maintenance	219,764	143,806	Sec7 P197	219,764	143,806	121,587	245,916	245,916	245,916	245,916	245,916	245,916	501,522	Sec5 P5-5	
Hosting						1,054,080	1,404,768	1,404,768					418,750	Sec5 P5-5	
Service Year 1	837,302	700,000	Sec7 P167	837,302	837,302						800,000	800,000			
DB Admin for 1 Year	125,000	125,000		125,000	125,000				125,000	125,000	125,000	125,000			
Application Management															
Configuration Management - Hosting	229,000	114,500	Sec7 P171	229,000	114,500		304,367	296,758	304,367	296,758					
2nd Year and Following - Hosting	35,000	17,500	Sec7 P171	35,000	17,500										
Annual							443,708	488,501	443,708	488,501			1,031,250	Sec5 P5-5	
Total Marginal Annual Costs for Year 1	1,411,066	1,083,306		1,411,066	1,220,608	1,175,667	2,398,759	2,435,943	1,118,991	1,156,175	1,170,916	1,170,916	1,951,522		
Total Marginal Annual Costs (not including new staffing requirements)	1,217,066	986,306		379,764	286,306		2,094,392	2,139,185	814,624	859,417	370,916	370,916			
5 Year Ongoing Costs	6,279,330	5,028,530		2,930,122	2,365,832		10,776,327	10,992,681	4,377,487	4,593,841	2,654,580	2,654,580			
8 Year Ongoing Costs						9,405,336							15,612,173		

SEC#28	Original Budget	Additional known costs	Miscellaneous/ Contingency	Revised Budget
System implementation costs:				
Oracle Costs				
License	719,031	60,000	0	779,031
Travel	529,068	0	0	529,068
Training	154,776	0	0	154,776
Project Management	293,166	0	0	293,166
Customization	1,009,123	190,877	0	1,200,000
Implementation	1,205,598	0	0	1,205,598
Total Oracle Costs	3,910,762	250,877	0	4,161,639
EHM Implementation Costs				
Hardware	1,000,000	700,000	300,000	2,000,000
Internal Costs of Implementation	1,000,000	700,000	300,000	2,000,000
Conversion	0	500,000	400,000	900,000
Interfaces	0	300,000	0	300,000
Other Development	0	75,000	0	75,000
Project Office	0	300,000	0	300,000
Governance Review	0	100,000	0	100,000
Contingency	1,000,000	0	0	1,000,000
Total EHM Costs	3,000,000	2,675,000	1,000,000	6,675,000
Total Implementation Costs	6,910,762	2,925,877	1,000,000	10,836,639

SEC#28

CIS RFP Evaluation

September 25, 2006

The RFP

The RFP for the new CIS was issued by Enersource on behalf of Enersource Hydro Mississauga and Toronto Hydro. The RFP was issued to 4 implementers to obtain quotations on implementing a new CIS for Toronto Hydro and Enersource together, as well as each utility separately. Vendors were asked to quote on the software licenses, software maintenance and support. Vendors were also asked to quote 3 support options: Option 1 where the application would be outsourced, Option 2 where the application would run on servers owned by the requestor(s), but the vendor provided application support, and Option 3, where the group would support the application themselves, as they do with their current CIS systems.

In particular vendors were requested to quote on maintaining the system current with the changing Ontario regulatory environment. The system would also have to be implemented as compliant.

The Vendors were asked to complete a detailed functional checklist indicating the type of customization effort that would be required to implement a function, if it was not included in the delivered software.

Vendors were told that they could be required to demonstrate the specific Ontario requirements in the software as part of the RFP review process, as well as demonstrating other aspects of the system.

The Vendor Responses

All four vendors responded. Accenture and Siemens quoted SAP software, Accenture quoting only Option 1, Siemens quoting all 3 options. IBM and SPL quoted SPL software, with IBM quoting Option 1 only, and SPL quoting Option 2 and 3.

The Evaluation Process

When drafting the RFP, it was anticipated that a detailed functional review would be required in order to distinguish the best response to the RFP. As it turned out, this process was not necessary.

The dollar amounts quoted in the RFP responses were analyzed in a table to show the differences for all the different vendors and different options.

The functional checklists were scored and compared.

The vendors were each asked to a meeting in which they were given an opportunity to answer specific questions. This meeting was held in order to ensure that the evaluation team understood

the RFP responses. The meeting was also used to assess the vendors' understanding of the specific Ontario requirements and how they expected to maintain this understanding as requirements change.

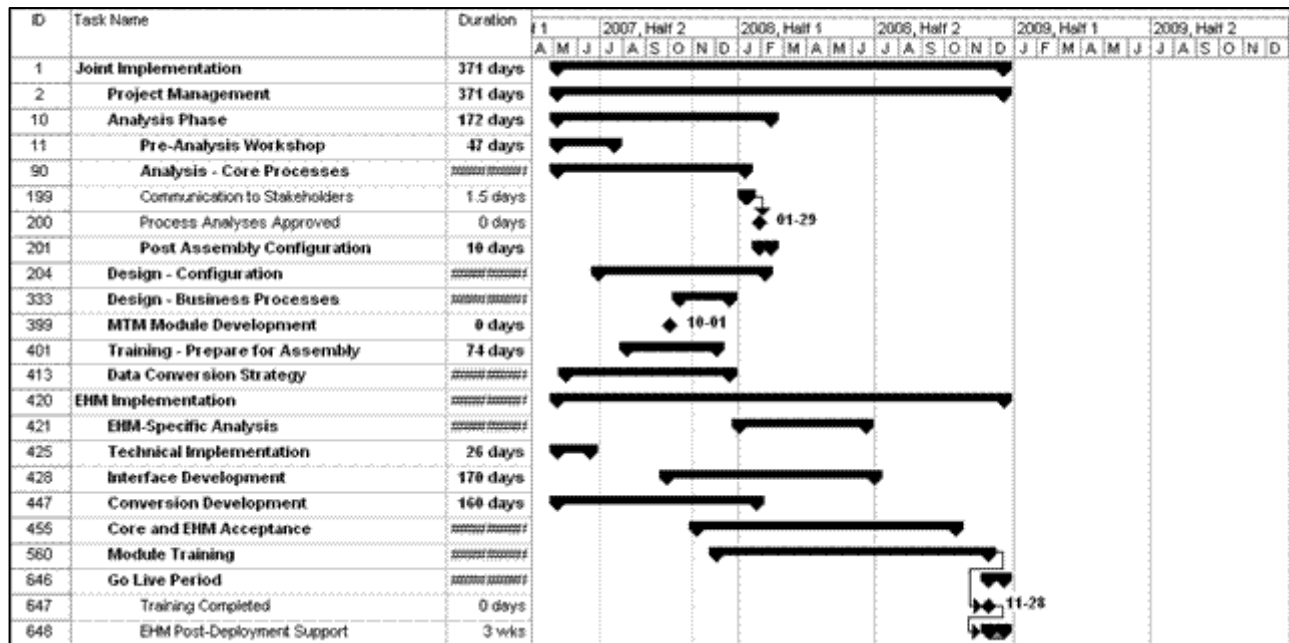
At this stage of the evaluation process, it was apparent that the vendors quoting the SAP software were unable to quote the implementation or maintenance costs of the maintaining the software in compliance with the Ontario regulatory requirements, in particular the EBT requirements. SPL and IBM through SPL were able to include this in their responses.

As this was a critical point for the evaluation team, it was decided that the vendors quoting SAP software would not be reviewed further.

SPL was asked to demonstrate their system as a whole and their ability to perform the Ontario specific EBT transactions. This demonstration satisfied the evaluation team that the SPL software would meet our business requirements.

The SPL and IBM quotations offered the same software. The software would be licensed and maintained by SPL in both cases. The IBM quotation was significantly higher than the SPL quotation for implementation. The business model proposed by IBM involved a group of 3 utilities, including Hydro Ottawa, rather than a group of 2 utilities; the business model proposed by IBM for running an application for 3 utilities was more complex than the cooperation between Toronto Hydro and Enersource Hydro Mississauga together. The selection team did not feel that the IBM proposal provided enough extra value to compensate for the added costs and complexity involved in the proposal.

Accordingly, it was decided to notify Accenture, Siemens and IBM that their proposals were not accepted, and to inform SPL that although the RFP was not awarded, SPL was identified as a preferred vendor and that the group's intention was to work with them to negotiate an agreement.





REQUEST FOR PROPOSAL
CUSTOMER CARE AND BILLING SOLUTION
RFP Number EC2006-008.

Date Issued: March 27, 2006
Date Due: April 24, 2006

Mail Responses To:
Enersource Hydro Mississauga
c/o Purchasing Manager, Enersource Corporation
3240 Mavis Road
Mississauga, On
L5C 3K1

Direct RFP Questions To:
Email: EC2006-008@enersource.com

The Group reserves the right to cancel this RFP at any time. The Group reserves the right to abandon, without obligation to the Vendor, any part of the project, or the entire project at any time before the Vendor begins any work authorized by the Group.

Proposed Timeline:

Issue RFP:	March 27, 2006
Last date for vendor to submit notice of intent to bid:	April 5, 2006
Last date for vendor inquiries:	April 10, 2006
Last date for responses to vendor inquiries:	April 13, 2006
Last date for proposal submission:	April 24, 2006
Bidders Meeting	March 31, 2006 10:00 AM
Ontario market ready demonstration by vendor(s):	To be determined, approximately 6 weeks after RFP Issue date
Further demonstrations by vendor(s):	To be determined approximately 6 weeks after RFP Issue date
Announcement of decision:	On or about May 10, 2006

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Confidential Information is not to be shared with any other party without the prior written consent of
 Enersource Hydro Mississauga Inc. & Toronto Hydro Electric System Limited

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1. INTRODUCTION

1.1. Confidentiality

The material contained within this RFP (and any attachments and subsequent amendments thereto) is provided to the Proponent in conformity with the understanding, outlined in the Confidentiality Agreement attached as Appendix A hereto, concerning the disclosure by Enersource Hydro Mississauga Inc. (EHM) and Toronto Hydro-Electric System Limited (TH) to the Proponent of certain information relating to this RFP. As used herein, the terms “Proponent”, “proponent”, “Vendor”, or “vendors” refer to each party to whom this RFP is issued.

The Proponent acknowledges that this RFP (and any attachments and subsequent amendments thereto) are, and will remain, the property of EHM and TH which is confidential and material to the interests, business and affairs of each of EHM and TH and that disclosure thereof, or use thereof in a manner not provided for in this RFP, would be detrimental to the interests, business and affairs of EHM and TH. Accordingly, the Proponent agrees to execute and be bound by the terms of the Confidentiality Agreement attached as Appendix A hereto, and to maintain the confidentiality of this RFP material and any subsequent attachments and amendments thereto pursuant to the terms of the said Confidentiality Agreement.

1.2. Background

Two Ontario utilities (Enersource Hydro Mississauga Inc., and Toronto Hydro-Electric System Limited, “the Group”) have identified a desire to utilize a common Customer Information System (CIS) for customer care and billing. The CIS is intended to align with individual LDC business strategies and the common goals of the Group, as well as to explore the benefits associated with the outsourcing of this technology, its development, and ongoing support to a single vendor on behalf of the Group.

Notwithstanding the foregoing paragraph, to be clear, each utility may individually determine, in its sole discretion, to select different vendors or CIS's or to not proceed with any of the proposals received for a CIS. Further, even if the Group does determine that it will proceed with a common CIS, each utility will enter into its own separate contract for the applicable successful proponent.

Enersource Corporation (Enersource) is issuing this RFP to solicit responses from companies from whom the Group, or any member of the Group, may procure a comprehensive CIS.

Enersource is acting strictly as an agent on behalf of EHM in connection with this RFP, and in turn, EHM is acting on behalf of the Group. Accordingly, Enersource assumes no responsibility with respect to any obligations under any agreement that may be reached between EHM or any Group member and any successful Vendor as a consequence of a response to this RFP.

EHM, except in its capacity as an individual member of the Group, is acting strictly as an agent on behalf of the Group in connection with this RFP. Accordingly, EHM's only obligation to a successful Vendor will be pursuant to a definitive agreement, if any, between EHM and such successful Vendor and EHM assumes no responsibility with

respect to any obligations under any agreement that may be reached between any other Group member and any successful Vendor, if any, in response to this RFP.

It will be the responsibility of each participating Group member, in its sole discretion, to enter into a separate definitive agreement with a successful Vendor for the provision of a CIS. While the Group members are each participating in this RFP, there is no commitment by either EHM or TH to procure a CIS and to enter into an associated definitive agreement with any successful Vendor. EHM assumes no responsibility or liability with respect to any Group member's decision to procure or not to procure a CIS.

EHM is one of the larger electrical distribution companies in Ontario, with 180,000 customers. Its parent company, Enersource Corporation is 90% owned by the City of Mississauga, and 10% by BPC Energy Corporation, a subsidiary of the Ontario Municipal Employees Retirement System.

TH is a local electric distribution company in Ontario, delivering electricity to a broadly diversified, economically robust, residential, commercial and industrial customer base in the City of Toronto. TH's parent company Toronto Hydro Corporation is owned 100% by the City of Toronto. The utility distributes approximately 18% of Ontario's electricity and serves approximately 677,000 customers.

The Group is currently evaluating options to replace their current in-house supported CIS, with the goal of moving to a packaged solution supported and maintained by the vendor. This application is critical to the distribution companies' operations, recording energy billings of over \$3 billion (collectively) and enabling important customer service activities. Since market opening in May 2002, CIS applications have been heavily affected by regulatory change thereby putting additional stress on the Information Technology and Customer Service departments. Optimally, the Group would like to move to the same CIS product and develop a means for the support and maintenance of this software, in order to reduce the risks involved in in-house support and reduce the total costs of on-going regulatory compliance and CIS operations in the long term.

The Group has been meeting with a number of other large electrical distributors in Ontario who have similar interests. The Group hopes that these other local distribution companies will follow the Group's lead in adopting a common Ontario retail market ready software supported and maintained in regulatory compliance by the vendor. Vendor-supported software would also allow the Group to benefit from constantly improving features, the improved flexibility of newer software, and thus increase the level of service the CIS provides the customer service department and the level of service that the Group is able to provide to its customers. The Group also anticipates that the flexibility and increased power of more current software may be of benefit in adopting the changes required as part of the Smart Meter initiative.

The Group is considering various options in the delivery of CIS software - ranging from licensing the software separately and running it in-house as it does today, to a complete ASP solution where the vendor supplies software, hosting, maintenance and all support, maintaining the mandated regulatory changes and future system enhancements

In this request for proposal (RFP), the Group is requesting proposals for each of their own CIS operations individually, as well as the operations of the Group together, and for

each Group combination, and further for pricing for a possible consortium with up to 1.6 million customers, or in increments of 200,000 additional customers. To be clear, while the Group anticipates that proposals will reflect certain economies of scale from the Group selecting the same CIS, each utility will contract separately with the successful proponent(s), if any.

1.2.1. Definitions

In this RFP, the following terms are used:

Base software: Software as ordinarily delivered by a software vendor to any purchaser, sometimes referred to as “vanilla software”.

Core software: Base software plus configuration and modifications required to meet the requirements of the Ontario de-regulated electricity market as defined by regulation and the Ontario Energy Board, plus configuration and modifications required to meet the common business processes of the Group.

Individual customization: Modifications to core software required to meet requirements unique to a member of the Group.

2. RFP SCOPE

The Group is releasing this RFP in order to procure a comprehensive customer information system. This RFP will consider the following:

Packaged CIS Solution: A vendor developed CIS product will be licensed, configured, customized and implemented. The vendor will provide ongoing product support and enhancements under an annual support agreement. For further details see Table 2.1.1 below.

Maintenance of Ontario Regulatory Requirements for electrical distributors: The vendor must also commit to the ongoing support of the Ontario EBT Standards, the Retail Settlement Code and all other regulatory changes as prescribed as part of their offering.

The Software will deliver functionality as outlined in Appendix B.

Conversion: the vendor will convert data from the existing legacy system.

Interfaces: The vendor will provide interfaces to the CIS as noted in Table 2.7.1 and Table 2.7.2 of this RFP.

Reports: The vendor will provide a summary list as well as a soft copy of their standard reports and include in their client reference list one or more companies that use their standard reports in their normal business operation. The project will also include the development of critical custom reports. The RFP response will include an indication of the costs for delivering custom reports, such as time and materials rates.

Training: The vendor will train the Group project team and provide their proposed training schedule and agenda based on the maximum client benefit. The Group project team will train the end users.

Training Documentation: The vendor will provide comprehensive end user training documentation. The vendor will confirm if the training material is currently available in soft copy upon request, or if their training material is under development. Points will be awarded for the former, and discounted for the latter.

Project Plan: The RFP response will include a high level project plan including timelines, and resource loading including the Group's project team. The plan will note the qualifications and time commitments required of the Group project team, including senior project team members.

Vendor project team: The RFP response must include the vendor's proposed project team, including resumes. The successful vendor's project team will include representatives from the CIS Software vendor. The Group reserves the right to accept or reject proposed members of the project team at any stage during the project.

Data Modeler for ongoing analysis: The RFP should include separate pricing for this product assuming all members of the project team will be users.

Software testing tools: The vendor will recommend automated testing tools, and include training for the Group team on these tools.

Data warehouse/business intelligence/ executive dashboard tools: The vendor will provide a data warehouse and an extraction and load process from the CIS to the data warehouse. The vendor will load the data warehouse with data the Group has extracted from its current system(s).

Archiving tools: the vendor will provide archiving tools for data and outline their methodology for data archiving.

Complex billing engine: the CIS solution will include a complex billing engine capable of calculating billing values for interval commercial and industrial accounts, and capable of calculating NSLS values for non-interval billing according to Ontario rules.

Test Regions: The vendor will provide a tool to build test regions with a sub-set of customer data to facilitate testing.

Customer Web portal: The vendor will provide a web portal where customers are able to inquire and update selected information and initiate requests.

IVR solution: The vendor will provide an Interactive Voice Response solution to provide customers with information over the phone.

Meter Data Management and Repository System: Some elements of an MDM/R solution as contemplated by the Smart Meter legislation in Ontario have been included in the scope above. The requirements of the MDM/R are not defined at the time of the release of this RFP. The vendor will provide an estimate of other modules that would be required in order to fulfill the function of an MDM/R and their cost.

Computer Telephony Integration: The vendor will provide inbound "screen pops" and outbound predictive dialing applications.

All hardware and software required for a comprehensive solution including any additional third party hardware and software licenses: Telecommunications or networking requirements for a hosted solution should be described but are not included in the scope of this RFP.

2.1. Comprehensive Customer Information System Solution: Options

As part of this RFP the Group is considering any one of three different operational models. A vendor may respond to one or more of these models as part of the RFP.

Option 1: Externally Hosted Packaged CIS Solution

Each of the members of the Group will expect to contract with the vendor for this option. Various companies may be sub-contracted by the vendor for hosting, application support or other services.

The vendor will deliver CIS functionality as a service designed to meet specific business objectives related to customer care and billing and provided under specific service level agreements (SLAs).

The CIS product will be licensed, configured and customized to meet each of the Group member's needs, but physically located (hosted) by the vendor or a third-party with functionality delivered via robust, dedicated communications to the each Group member's network.

The vendor will provide all necessary hardware, software and resources required to meet the service level requirements, as well as the daily billing production, system backup and disaster recovery services.

Each of the Group members will own the core software licenses and any customized code.

The vendor will be responsible for the change management to the production environment that includes, but is not limited to, QA/QC, testing, version control.

Option 2: Internally Hosted infrastructure, External Application Management Service

In this option, each of the Group members will individually host the application in-house.

The vendor will provide Application Management Services to each of the Group members.

The Application Management Services will include all work related to the application maintenance, break/fix, fine-tuning, and 2nd level support for the CIS applications.

The vendor will provide software maintenance, configuration and testing, disaster recovery services using each Group member's infrastructure.

Each of the Group members will be responsible for regular daily operation support including batch functions, job scheduling, 1st level support to all user functions and access administration.

Each of the Group members will own the core software licenses and any customized code.

Option 3: Internally Hosted Infrastructure, External Application Maintenance of Ontario-localized CIS Application, Internally Managed Packaged CIS Solution

Core software will be implemented at each Group members' premises. The CIS product will be licensed, configured and customized to meet the Group's needs.

The vendor will provide Application Management Services on a localized CIS that meet all the regulatory requirements from Ontario (core software). Future upgrades and other regulatory changes to the base system will be the responsibility of the application maintenance provider.

Group members will build and maintain customized enhancements and interfaces to the base system.

The customized application would be supported and enhanced in total or in part by the Group member staff.

This model fits the current staffing and business models of the Group.

Each of the Group members will own the core software licenses and any customized code.

Table 2.1.1. Packaged CIS Solution. Details of Scope

Component	Description/Inclusions	Option 1	Option 2	Option 3
Software Licenses and Maintenance				
Base Software	License fees for CIS system	IN	IN	IN
	Software Maintenance Fees	IN	IN	IN

Application Management Services				
Application Management	Customizations as a result of regulatory or process changes	IN	IN	IN
	Ongoing improvements in technology standards to ensure that the CIS continues to be based on current industry standard	IN	IN	IN
	Application support and services	IN	IN	IN
	Release management	IN	IN	IN
	System documentation	IN	IN	IN
	Team Lead training, end user training will be supplied by the Group for their own staff	IN	IN	IN
	2nd level Application Support	IN	IN	IN
Software Customization & Platform Configuration				
Customize Core Software	Detailed fit-gap analysis of software functionality to business requirements	IN	IN	IN
	Specification and development of common customizations and interfaces	IN	IN	IN
	Vendor support of core software	IN	IN	IN
Configure Core Software Solution	Configuration of customized CIS for common business practices and common interfaces	IN	IN	IN
	Data Conversion	IN	IN	IN
	System Test plan and testing	IN	IN	IN
	User Test Plan	OUT	OUT	OUT
	User Acceptance Testing	IN	IN	IN
	Change management of new/changed business processes	IN	IN	IN
	Application training of project team	IN	IN	IN
Individual Customization -- Configuration	Detailed fit-gap analysis of software functionality to business requirements	IN	IN	IN
	Specification and development of individual customizations and interfaces	IN	IN	IN
	Ongoing vendor support of individual customization	IN	OUT	OUT
Individual Customization -- Customization	Configuration of customized CIS for individual business practices and unique interfaces	IN	IN	OUT
	Data Conversion	IN	IN	IN
	System Test plan and testing	IN	IN	IN
	User Test Plan	IN	IN	IN
	User Acceptance Testing	OUT	OUT	OUT
	Change management of new/changed business processes	IN	OUT	OUT
	Knowledge transfer to Group customization team	OUT	IN	IN
	Ongoing vendor support of individual customization	IN	OUT	OUT

Hosting and Provisioning of the system				
Host— Installation	Hosting of the system in an external data centre	IN	OUT	OUT
	Installation and configuration of hardware-specific environments	IN	IN	IN
	Provision of capacity and bandwidth to support service levels	IN	OUT	OUT
	Development of support requirements and procedures	IN	IN	IN
	Change management/training re new skills requirement as requirements change over time	IN	IN	IN
	Annual Audit & Control	IN	IN	IN
Hosting ongoing management of the hosted environment additional requirements	Daily operation support including the completion of all batch operations	IN	OUT	OUT
	Load monitoring and capacity management	IN	OUT	OUT
	Infrastructure maintenance	IN	OUT	OUT
	Infrastructure security	IN	OUT	OUT
	Redundancy Planning	IN	OUT	OUT
	Backup and restore activities	IN	OUT	OUT
	Disaster recovery planning	IN	OUT	OUT
	Release management	IN	IN	IN
	Coverage for insurance and business interruption	IN	OUT	OUT
	Performance benchmarking	IN	OUT	OUT
	Maintain hardware and system software technically current	IN	OUT	OUT

2.1.1. Service Levels

This section outlines the key service levels desired by the Group in case the application hosting option (i.e. Option 1) is selected and awarded. The Group anticipates that these service levels will be formally defined, and additional service levels and/or threshold levels for services below, may be identified in consultation with the successful proponent, based on industry standards and the specific solution proposed by the successful proponent.

Table 2.1.2. Service Levels for Application Hosting

Service Level	Desired Service Level
System Performance	
System Availability – peak hours*	99.9%
System Availability – non-peak hours	99.0%
System Response Time	1 second or less unless specifically itemized in the response
Average Batch processing time	2 hours
User Support	
Help Desk call response rates	80% calls within 30 seconds
Average Call Resolution Time	1 hours
System Reliability	
Time to recover from failure	15 minutes

* 7.00 am to 6 pm, Mon-Fri

The Vendor will state assumptions and factors and will guarantee the system response time and batch processing time for the proposed configuration and test conditions. The achievement of performance will be subject to inspection by Group members through use of a performance measurement tool as agreed to by the Group and the Vendor.

As noted above, the Group is expecting a system that will respond to all on-line transactions within an average of one (1) second or less. Exceptions to this response level, due to the complexity of the transactions, are to be itemized by the Vendor, as suitably qualified to give recognition to the impact of system size and variability of loading.

The system should be configured to perform batch billing of accounts as indicated here –

12,000 bills produced per day – 2 hours elapsed, maximum
 35,000 bills produced per day – 5 hours elapsed, maximum

Test conditions will include all necessary daily meter data transactions (via whatever MDM/R integration is implemented for the Ontario market) plus all retail transactions via EBT.

Performance values in these areas must be sustainable with anticipated growth.

Scalability is to be addressed in the response –
 maximum volume of transactions supported by proposed solution,
 incremental investments to achieve higher transaction volumes, in increments of 10,000 bills per day up to 100,000.

2.2. Technical Requirements

The response is to address Technical Requirements according to which Options are being proposed (see section 2.1).

Summary of responsibilities under proposed Options:

For Option 1 –

The hosting company is taking full responsibility for meeting service levels and can employ whatever techniques and operational optimizations and approaches over time that are consistent with achieving this outcome and consistent with appropriate outsourcing practices for an enterprise-wide essential business process, including appropriate redundancy and disaster recovery procedures. The Service Level Agreement would provide the context for what is expected, included and allowed.

For Option 2 -

The vendor will identify the computer hardware and system software platform required to install and operate the proposed application at the intended level of service, but the acquisition and installation of hardware would be the responsibility of the Group member. The Group member hosts the IT infrastructure required for the software product and is responsible for its provisioning, repair and replacement. The vendor is responsible for all application management and service management functions related to the use and updating of the application and so must have ready access to the Group member environments to effect changes and provide support.

For Option 3 –

The vendor will define supported reference architectures supported by the Ontario-localized CIS application and identify the computer hardware and system software platform required to install and operate the proposed application at the intended level of service, but the acquisition and installation of hardware would be the responsibility of the Group member. The Group member hosts the IT infrastructure required for the software product and is responsible for its provisioning, repair and replacement. The vendor is responsible for maintaining an Ontario-localized version of the CIS application and ensuring that it will operate successfully on the reference architectures and achieve acceptable performance on the recommended hardware.

Vendor Responsibilities

Option 1

The vendor provides the hardware and ensures its adequacy to meet all service requirements under conditions of installation and conversion, version upgrades, normal and emergency business operations, during application development, testing, quality assurance and commissioning and to explore potential new modules and features in demonstration mode. In sizing and specifying the hardware and operating requirements, Vendors should take into account that Group members will not be required to synchronize the timing for the commissioning of versions installs and upgrades but will be afforded the needed business flexibility to schedule these updates to align with their business requirements. In keeping with the stated desire by Group members to maintain their installed CIS versions to achieve timely regulatory compliance and to deliver service innovations to their customers, such updates would not be unreasonably

delayed.

Vendors submitting an outsourced infrastructure solution are required to define the server and related configuration housed within the outsourced facility.

Although the responsibility of the vendor, Group members will require that the specifics of the proposed, initial hardware installation be provided in support of vendor claims to achieve service compliance.

Selected benchmark performance will be tested as part of acceptance testing and periodically, as required, to verify ongoing service compliance.

The Vendors are required to disclose how they will maintain the privacy of customer data as required by Ontario and Canadian legislation.

Options 2 & 3

The vendor will specify the required hardware. As hardware under these options is at the cost of the Group members, incorrect sizing by the vendor or inadequate attention to computing efficiencies of the application introduces a project liability to Group members. Therefore, some shared interest by the vendor in the correctness of the recommendations is required and remedies provided for incorrect sizing that would result in additional cost and effort by the Group members. Vendors will suggest remedies to be applied.

The response must list all operating system, system software, run-time support software and middleware, support or utility software (all at appropriate release levels) to ensure consistent and effective operation. This software recommendation must be such that in quantity and quality it will support all Group member normal business operations, remote and local connectivity needs, and disaster recovery / business continuity requirements, initial and on-going testing, training, quality assurance, demonstrations to current and prospective users, and evaluations of new product releases. A detailed description of the proposed system configuration, associated system components, and available options must be included. All necessary installation and training services must be itemized, as applicable.

It is imperative that the recommended hardware solution support on-line response and batch performance requirements as described in Section 2.1.1. The vendor must include evidence in support of the hardware platform's ability to meet identified service levels. Selected benchmark performance will be tested as part of acceptance testing.

If the application operates on many different platforms the vendor must select a platform and submit it as part of the reference architecture portion of the solution. This is required to identify the total cost of the vendor's proposal. Subsequent discussions may alter the proposed platform.

For suggested hardware configurations, there must be allowance for linear growth within the same family of hardware, without replacement. All hardware initially purchased must be upgradeable to allow for expansion and continued use. It must be configured to accommodate users as noted in Table 3.1.2. It must be configured to accommodate

monthly batch billing and file maintenance cycles for the number of accounts noted in Table 3.1.1, while allowing for 5% annualized growth during the initial five (5) year production period.

The system must support high transaction volumes and the capacity to scale and address increased usage. Evidence from benchmarking and other sources must be provided in support of the recommended architecture and specific recommendations and in expectation of achieving the transaction volumes associated with Group member business sizes.

Storage requirements will be specified to ensure that disk space utilization will not exceed 80 percent of capacity during the initial five (5) year production period. The system must allow for expansion and must be configured for: conversion of the existing CIS databases of Group members, retention of 7 years of on-line history, 5 years of growth as well as account for RDBMS overhead (including archive logs, rollback segments, extensive indexing), system files, and system sort and workspace needs. Vendors are encouraged to suggest hardware approaches to Group members that provide for flexible storage management and highly available services.

Application-aware archive and purge capability will need to be provided as part of the base CIS product. If archive and purge is not part of the base CIS product, we will require documentation of procedures and an estimate of the cost of maintaining 36 rolling months of historical data and maintaining a semi-annual or annual schedule for the archiving/purging of older data by other means.

The vendor must propose a comprehensive system software environment which may include: Operating system software, application development tools, performance tools, education tools, system management tools, system security tools, utility tools, job scheduling tools, report distribution/archive tools, tape management/system tools, and disk management tools.

2.3. Database Software

The vendor will identify the relational data base management product and the associated query and reporting software being provided with a general description of the technical specifications and features of the software. Specifically, the vendor must provide a comprehensive RDBMS environment which may include: RDBMS software, query/report writing software, RDBMS performance tools, and RDBMS utility tools.

Notwithstanding the choice of option for operational management, the Group reserves the right to impose the selection of database management software from among those supported on the base CIS product. This right is preserved to ensure that any later decisions regarding changes to hosting and application support are made with full regard to Group interests. If pricing is a factor for a fully hosted option, the costs of various technical choices are to be provided.

2.4. Customer System Software

The vendor will identify the product(s) being provided with a general description of the functions and features of the proposed system. It is important for the vendor to include sufficient detail to provide an understanding of the product(s) being proposed.

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The vendor is asked to support claims for the generality of the product and its capacity to address future business requirements through such documentation as a high-level data model or entity relationship diagram representing the major data entities and relationships supported by the product. The extensibility of the data model in support of an Ontario-localized version or in extensions, as required for Group member custom configuration and interface implementation are to be supported with related documentation. Capacity to extend features, models, and process workflow as well as the ready ability to have such extensions survive version upgrades will be carefully assessed and any claims should be fully explained and supported by product documentation.

2.5. End-user Access and Connectivity

The vendor will identify potential or required approaches for connecting the proposed server hardware platform with the client desktop environments to allow user access to the new customer system. A description is to be provided of the communication, network, and desktop components needed to support this connectivity.

The vendor will be responsible for providing an analysis of Group member's current environments and identify, in terms of the proposed solution, missing components or changes required to support the proposed solution.

The vendor must specify all software required to be resident on the user desktop to access the application. A total of 185 user desktops will be configured with this software. The vendor must assume that there are 185 concurrent users, each reviewing 3 active accounts per session.

The vendor must identify and specify any hardware, software, or services required to connect the in-house or outsourced server to the Group's network.

2.6. Operation of the Group

The Group may choose to share in one solution or may each choose separate solutions, or may choose not to select any of the options presented by the vendors in response to this RFP. In the event that more than one member of the Group selects a CIS solution as a result of this RFP, those members of the Group intending to proceed to a shared solution would then undertake to cooperate with the vendor and with each other to create and maintain a core Ontario Market-Ready version of the software in compliance with the Ontario Market requirements, as they change over time. The Group would then contemplate committing resources to assist in joint business process design, configuration, modification of design (if required), and testing of changes required for regulatory compliance. This version would incorporate common business practices agreed on among the Group. The Group would be exploring the potential of creating and sustaining an Ontario-ready version of the software for use in individual or Group implementation.

2.7. Interfaces

The development and testing of interfaces is part of the scope of this RFP. The following are the interfaces that are required for each of the Group members.

Table 2.7.1. EHM Interfaces

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No.	Interface	Element/Description
1	MVRS (ITRON)	Non-interval meter reads.
2	Interval Meter Reads (MV-90)	Readings are taken via phone lines via MV-90. The MV90 data is sent to EVEC system for validation, estimating and editing.
		In other cases, interval reads are read by MV-90, converted into the equivalent non-interval reads and then sent to the CIS
3	Complex Billing and Settlement (Power Measurement)	The interface to the settlements application should be included in this application as the complex billing engine may not be put into production at the same time as the CIS system.
		Aggregation of individual meters to one meter (for CIS purpose)
		Calculation of NSLS
		Creation of BDF (Billing Determinant Files) files for NSLS for daily pricing info for non-interval accounts, which is sent daily to the CIS
		Creation of the NSLS EBT information for retailers which is sent via EBT and the CIS to the retailers daily
		Interface to IESO to receive statements and data
		Calculation of billing determinant files for CIS, which are sent on billing cycles to the CIS
		Maintenance of customer records (customer/premise/meter info) & retailer enrolment information via a daily interface to the CIS
		Creation of weekly and monthly usage for interval accounts enrolled with a retailer which is sent weekly and monthly via EBT to the retailers. Should be rules based to include/exclude by retailer preference which files they want to receive, or not receive (E.g. weekly usage)
		Historical usage EBT requests from retailers are sent from the CIS to Settlements, settlements creates the data and then send it back to the retailer via EBT and the CIS.
4	VEE (E&B) (Power Measurement)	Validates, Edits and estimates data from Interval Meters (MV90)
5	Kubra for bill print	For bill print
		For e-billing via E-post
6	Web Bill Presentation	N/A
7	Data warehouse: Cube	Monthly data is extracted for purposes of statistical analysis
8	PeopleSoft/JD Edwards Financial	CIS transactions are summarized and passed in a flat file to the general ledger in JDEdwards, where journal entries are automatically created by billing batch.

		Daily changes to customer/premise data is extracted from the CIS and interfaced to update the parallel record in the JDE system
		CIS payments are created in JDE, based on an interface from the CIS to the JDE system, for final bill refunds for example.
9	IVR	Customers may inquire on their accounts via IVR
10	Bank	Interface for EFT
		Interface for cash receipts
11	Cash Receipts Printer	Interface to POS printer for cash receipts
12	Service Order Scheduler	Daily service orders are downloaded to Palm Pilots. Meter readers complete the service orders on the Palm Pilot. Daily the completed service orders are uploaded from the Palm units, edited and updated to the CIS.
13	AMI Interface	Interface between an Automated Metering system and the CIS to synchronize data on which meters are in the field.

Table 2.7.2. TH Interfaces

No.	Interfaces	Element/Description
1	MINCOM -Ellipse ERP	Asset Management,
		Batch interface for GL feed from Banner
2	MV-90 Remote Interrogated Meters (RIMS) Interval Meter Reads	Interval meter reads; to be replaced by MV90xi in Q2 2006
3	Meter Readings ITRON MVRS	Regular cycle reads using hand-held data capture devices Upload and download meter reading files to third party contractors
4	SPi Hub Connect EBT Spoke	EBT interface between Banner and the SPi Hub system
5	DocuCorp DAP, WIP	Produces bill files for printing paper bills, eBills biller direct site, bill archive-retrieval for Banner customer service reps, bill exceptions
6	DocuCorp DocuPresentment Web ebill presentation	Biller Direct TH web site
7	Web site customer self-service	Customers provide meter reads & moves related data Manual interface to CIS Banner
8	LSIS Customer Connectivity Info	Receive Customer Load Data from CIS Banner in batch file
	CTI (computer Telephony Integration)	Account Self Service Screen pops based on customer data provided over the IVR system (account balance, last payment, etc. information as supplied from Banner)

		Meter Reading
		Call Routing
9	Bank	PAP Bank Drafts
		EFT (Electronic Funds Transfer)
		Payment Entries using Standard Bank File Format (RPM) via FTP
10	Electronic Payment	Telpay payments file for telephone and web payments via Telpay online pay service for eBills customers
11	Kubra eBills consolidator interface	File of electronic bills sent to bill consolidator via FTP
12	Coverall bill printing and mailing service	FTP bill fill produced from Docucorp to Coverall (bill printing services)
13	TMAN (Treasury Management)	Daily batch interface from Banner to provide billing and adjustment information to revenue forecasting system in Finance department
14	Interface to outbound collection call	
15	Interface to collection agencies	
16	Outage management	Outage management system and distribution management system
17	Workforce management	Field services automation
18	AMI	Advanced metering interface for smart metering hourly interval time of use

2.7.1. Collection Agencies

It will also be necessary for the CIS to interface with collection agencies or deliver specific file formats to those agencies for accounts referred to outside collection. Account status on referred accounts should support ongoing account updates as appropriate.

2.7.2. Bill Production E-Commerce

This solution will support flexible bill design formatting, pre and post printing checks (bill totals, dollar totals, highest bill dollar value, etc) on-line bill imaging, and will interface with Kubra for Electronic Bill Presentation and Payment

2.7.3. Metering and Consumption

The solution will support regulatory requirements for metering, including meter sampling and re-verification requirements from Canada Measurement. The solution will support Ontario meter reading validation requirements.

2.7.4. Other Requirements

Effective, efficient data mining, ecommerce, computer telephony integration and useful, but not intrusive interactive voice response are also considered within scope.

3. CURRENT CIS ENVIRONMENT

3.1. Current CIS Applications

The current EHM CIS is an Orcom based system, heavily modified for the Ontario de-regulated market, running on an AS/400 (i series) server, written in RPG. It includes a comprehensive retailer transaction module and a meter management module. The presentation layer is via web and terminal emulation on Intel/Microsoft based desktops.

Currently Toronto Hydro-Electric System Limited runs Indus Banner version 2.2.6 based CIS application. Hosting services are managed in-house.

Table 3.1.1. Business Metrics for the Group

METRICS	Enersource	Toronto Hydro
Meters	180,000	680,000
Total bills produced/year (in M)	1.2	4.6
Total number of accounts	178,371	677,000
Total number of EBT transactions (in M)	1.2	2
Total number of meter read/year (in M)	1.1	4.6
Total number of customers	180,000	677,000

Table 3.1.2. Individual CIS Environments

Hydro	Enersource	Toronto
Total On-line CIS Users	180	300
Concurrent CIS Users*	50	135
Current System	Orcom	Banner
Application Mgmt/Hosting	In-house	In-house
Interfaces	13	18
* Includes Customer Service, Call Centre, Billing, Payment, Collections, IT.		

4. PROPOSAL INSTRUCTIONS

The vendor will define the capabilities of its organization to design, implement, maintain, and support the solution components as outlined within this RFP.

Vendors are expected to examine the entire RFP including all specifications, standard provisions, and instructions. Vendors should provide their best estimate of cost based on the information contained in this document.

The vendor will segment their proposal into the sections presented in the following paragraphs.

4.1. Transmittal Letter

The transmittal letter will indicate the intention of the vendor to adhere to the provisions described in the RFP without modification. The letter of transmittal will:

Identify the submitting organization;

Identify the person, by name and title, authorized to obligate the organization contractually;

Identify the contact person responsible for this response. Specify, phone, fax, and email address;

Explicitly indicate review and acceptance of the Terms and Conditions and identify exceptions or "deal breakers";

Signed by the person authorized to contractually obligate the organization.

4.2. Executive Summary

The vendor will provide an executive summary that presents in brief, concise terms a summary level description of the contents of the Proposal.

In addition, the vendor must clearly and specifically detail all exceptions to the exact requirements imposed by this RFP.

4.3. Vendor Profile

The vendor will provide a profile of its organization and all other companies which will be providing products or services either through a subcontracting arrangement with the vendor or through a separate contract to be negotiated with the Group. At a minimum the vendor will provide the following information:

Year established;

Description of corporate structure, including organizational chart identifying the vendor's parent, subsidiaries and other affiliate corporations, partnerships and organizations;

Subsidiary offering product;

Office locations and denote satellite locations where applicable;

Support office for this project and Hours of availability;

Products available;

Total number of full time (35 hours or more per week) employees paid directly through vendor, and number of part time (less than 35 hours per week) employees, and/or third party contract companies and number of employees; Number of offices in Canada;

Current product release number and date of release;

Product History;

Expected date of next release and proposed enhancements;

Number of employees focused on the product offering;

Number of client installations, and number using current release;

Number of installations in the last 5 years by service type and account/customer totals;

Number of signed client contracts in process;

Last 2 years of financial data including gross sales and net income;

Current credit rating and name of rating agency; and

The vendor may attach any additional literature and product brochures.

4.4. Vendor Qualifications

The selected vendor must:

- (a) Be committed to the ongoing development of the product in the long term
- (b) Have a long term commitment to a reduced total cost of ownership for its customers
- (c) Be able to demonstrate ongoing commitment to maintaining the software in compliance with the Ontario regulatory environment
- (d) Be proven in deregulated markets in the utility industry
- (e) Be financially sound
- (f) The vendor will provide a customer references for at least 2 customers of similar size and complexity with related contact information including: customer name, site location, industry, customer base, user base, implementation date, product name/version number, and brief description of the engagement.

4.5. Technical Requirements

The vendor is to respond to technical requirements according to the operational management options that are being proposed (see Section 2).

4.6. Installation Plan & Services

The vendor will present an installation plan addressing three major components of the proposed solution: the project timeline; project approach; and project organization.

4.6.1. PROJECT TIMELINE

The proposed solution must include a project plan identifying activities, resources and timelines required for successful installation of the proposed solution in a specific period of time. Project plans should begin no earlier than May 10th, 2006.

Included should be a timeline demonstrating the sequence of events from the point of contract award through final user acceptance. Include Gantt Charts (or similar graphic depiction) to illustrate phases, activities, tasks, comments, milestones, decision points, and deliverables.

If the vendor is recommending a phased approach all phases should be reflected in the timeline.

4.6.2. PROJECT APPROACH

The Group understands that each vendor normally brings their own proven implementation process to the table. The Group expects the vendor to work under the umbrella of an overall PMO.

The Group anticipates that members will not implement the new CIS simultaneously. For instance, EHM may start its implementation first, followed by TH.

While the vendor may submit a bid which utilizes the products and/or services from several vendors, the Group is seeking a primary vendor or single point of responsibility regarding the successful completion of this installation effort.

The vendor must provide the following service components:

4.6.2 (a). Project Management

A Project Manager (PM) Triad approach will be followed. An overall PM identified, selected and agreed to by each member of the Group will oversee all work and provide specific day-to-day guidance and assistance to a vendor PM and the Group PM. The vendor PM will manage the vendor deliverables and resources, while the Group PM will perform a similar function for the Group. The overall PM will insure coordination across these two groups and serve as the first stop for issue resolution.

The vendor PM and the Group PM will be responsible to the overall PM for the following areas for their team: resource supervision; work program administration, coordination; resource time and expense management; and status reporting.

The vendor PM is required to provide a weekly written project status report to the overall PM and to assist in formal monthly and quarterly status reports to the Group management. The reporting period begins with the award of contract and continues through the post go live review period.

4.6.2 (b). Product Configuration

The vendor will be responsible for providing the core software and preparing it for operation and access by the project team.

The vendor will be responsible for training the Group core team in the core software, assist with set-up and configuration of the core software to accommodate the Group's specific environment, and continued training of the Group core team in order to achieve a level of product proficiency.

4.6.2 (c). Product Engineering

The vendor will be responsible for the identification, finalization, and documentation of the Group required modifications; the development of design specifications; modification of base product code; and unit testing of the product. This will include the work effort associated with designing and developing the bill format.

4.6.2 (d). Product Conversion

The vendor, with assistance from the Group, will be responsible for conversion of data from the existing CIS to the new customer system. Activities will include data mapping, development of conversion specifications, conversion programming, conversion testing, multiple mock conversions, data clean-up, manual conversion, and production conversion. The vendor will provide pricing for the extraction from the current system separately from the loading of the new system, explaining what elements of the conversion are in each section.

4.6.2 (e). Product Reporting

The vendor will provide the Group with a series of standardized reports (hard and soft copy) as part of the base product. Include a list of the reports available with the system.

Include additional time based upon vendor experience required to modify and enhance the standard product report offerings.

4.6.2 (f). Product Interfaces

The vendor will be responsible for developing design specifications addressing product modifications required for defined interfaces. Once approved by the Group the vendor will modify base product code and successfully unit test and component test the product. The desire is to interface with Industry Standard APIs where possible and to create specific interfaces where necessary, but in all cases to do this work with the understanding that the CIS vendor will insure that the interfaces included in core software are migrated with CIS application upgrades.

4.6.2 (g). Product Documentation

The vendor will be responsible for providing system and user documentation for the core software. The vendor will maintain the core software documentation as required to reflect the Group customization. This custom documentation must be delivered a minimum 30 days before system acceptance of custom upgrades, and/or be delivered a minimum of 120 days before a base version upgrade.

The vendor will provide at least one master and one copy of systems documentation for hardware, operating software and applications software, as well as system to each member of the Group.

4.6.2 (h). Administration Documentation and Training Manuals

Electronic copies in MS Word 2003 format are required. The vendor will grant the right to make as many documentation copies for use by the Group employees as needed. In addition, as part of the ongoing license fee, the vendor will provide one master and one copy of all documentation upgrades for all future system modifications and enhancements.

4.6.2 (i). Product Training

A core team has been identified at the Group and these team members along with other key implementation team members, system administration and system support personnel should receive extensive training appropriate to their implementation and production roles. Experience suggests that a train the trainer approach can be most effective, if the initial vendor training includes both soft skills and product knowledge. It will also require the vendor to deliver the training materials and the first onsite class with the Group trainer observing and assisting the first class while those roles are reversed for the second onsite class. All end user training will be conducted within the Group training facilities.

The vendor will provide a training plan identifying the minimum number of training hours that will be provided as a part of the base package. The plan will identify the actual training staff, hours, materials, and describe the size and assumed skill levels of each group and the functional responsibilities covered in each session.

4.6.2 (j). Product Testing

The vendor will be responsible for conducting a comprehensive systems test utilizing the Group's environment and data. Though the work plan will likely assign testing responsibility to the vendor, verification testing by the Group is required before acceptance.

The vendor will develop a test plan outlining the testing approach, methods, data participants and other items required for successful product testing.

The vendor will assume responsibility for conducting a product integration test to insure the delivered product modifications and product interfaces work to specifications and do not adversely impact the system as a whole.

The vendor will assume responsibility for conducting a product volume test to insure batch and on-line performance meets performance and service levels. This test should occur early in the implementation as failure here will result in the project being halted.

The vendor will assume responsibility for conducting a successful mock production conversion in preparation for production cut-over. Successful will be prescribed by achieving a 100% mock production conversion, and/or to the % satisfaction level of the Group agreeing to sign off as the mock conversion being successful. The vendor will provide resources for product fixes resulting from errors identified during the system testing process.

4.6.2 (k). Product Installation

The Group will review the final results of all product testing and the mock production conversion before accepting the readiness of the system and approve production cutover. The Group will make the final decision to cutover. A go-live team including the vendor and the Group resources will stage all aspects of the system, develop a final conversion schedule and conduct all cutover activities.

Following successful conversion and under direction of the vendor, the Group will conduct manual conversion activities as required.

4.6.2 (l). Post Installation Support

The vendor will provide immediate production critical issue resolution during the first 30 days of operations. In addition, the vendor will perform a post installation review to identify production issues and develop an action plan and associated timeline to address these issues.

4.6.2 (m). Final System Acceptance

The vendor will agree to a period of one hundred and forty-five (145) days following production cutover in which each member of the Group will conduct a shakedown of the system to measure every aspect of the system in order to insure compliance with all contract performance criteria. The project is not considered complete and the vendor will not be released from their implementation obligations until this final acceptance test is conducted and the system has been formally accepted by each member of the Group.

Until accepted, the system remains in the implementation phase and the support phase has not begun.

4.6.2 (n). Project Expenses

The vendor will identify reasonable travel and living expenses to be incurred during the course of this project. Individuals assigned to the project full-time and working onsite should be classified for expense purposes as being on an extended out-of-town assignment. A per diem approach is preferred as is an overall cap on travel and living expenses through to the successful completion of acceptance testing by the Group.

4.6.3. PROJECT ORGANIZATION & STAFFING

The vendor should present specific resources to this project, not representative resumes subject to the project commencing no later than May 15th, 2006. These should be organized in a project organization chart outlining the reporting structure and primary responsibilities of each position. They should also be identified on the Project Plan as dedicated resources 100% of the time, and/or the number of business days the specified resources will be made available to the project which should align to the specified and eventual actual days needed for each assigned task within the vendor's project plan. (Example: Data conversion may be specified as requiring 150 days, so the assigned vendor resources for data conversion should be identified as available 100% of the time for the scheduled 150 days during data conversion. If the actual data conversion ends up taking 180 days, then the vendor needs to keep their commitment to maintain the assigned resource to the project for the actual days required to complete the assigned task.)

The vendor will provide all personnel required to successfully complete proposed project. Vendors should recognize that changes in key project personnel will not be allowed subsequent to award of contract without written consent of the Group. Additionally, the Group reserves the right to approve any and all personnel changes or to request personnel changes as the Group deems appropriate during the course of the project.

4.7. Ongoing Support

At a minimum, the solution must include information associated with all aspects of ongoing support and maintenance activities. Depending on the option selected, this support may include: data center operation, hardware maintenance, software maintenance, product help desk, product fixes, product enhancements; and regular product releases based on a defined ongoing maintenance fee. This support should be managed using an issue tracking software application with prioritization functionality.

The Group requires that each cost be broken down as described below for each element as well as for all permutations of group membership in the order illustrated above.

Table 4.7.1. Cost Components

Cost Component	Description
Fixed component	Cost unrelated to size, scale or number of "units" (units = qty meters, customers, accounts, etc)

Variable component	Cost “per unit” (costs which vary directly with size)
Scale component	Cost “per unit” decreases which result as scale (number of units) increase (logarithmic component)

4.7.1. UPGRADE STRATEGY

The vendor will explain how often customers are required to upgrade and how long the proposed version of the software will be supported. The vendor will estimate the effort that a customer the size of the Group generally may be expected to expend on a regular upgrade of the software.

The vendor will describe the process for the Group to request future product enhancements and upgrades, and the availability of user groups for the utility industry.

4.7.2. PRICING

The vendor will provide a detailed breakdown of all costs in Canadian dollars required for the successful implementation and ongoing operation of the proposed solution. The Group encourages the vendor to fully identify costs associated with the proposed solution. To minimize or hedge on product costs will only serve to place the Group and the vendor at a disadvantage. *All reference to costs by the vendor response need to be in Canadian dollars, not in U.S. dollars, please refer to section 7.22 Price Sheets and Appendix D.

The Group recognizes that the implementation of a comprehensive customer system solution is a complex effort and that not all possible variables are provided for within this RFP document. Therefore, it is acknowledged that the vendor may be required to make some assumptions about the Group's environment or about specific requirements. Any assumptions made by the vendor shall be documented in this section to allow for specific pricing.

The Group is requesting the vendor provide specific cost information as outlined within the attached cost tables. The cost tables must be completed and are mandatory to be considered responsive to the RFP. Fixed price or not to exceed pricing is encouraged.

4.7.3. VENDOR PARTNERSHIP FINANCING OPTIONS

The vendor, as appropriate, should provide the Group with alternative partnership plans that may involve installation cost sharing, ongoing cost sharing, and/or profit sharing from subsequent sales. The vendor should also provide information related to financing options, lease options or other program offerings available to the Group.

5. PROPOSAL EVALUATION

The Group will individually and collectively conduct an evaluation of all eligible and responsive vendors submitting proposals in response to this RFP. The successful vendor(s), if any, will be selected based on evaluation factors outlined in this section.

5.1. Evaluation Criteria

Each Group member may award a contract to the vendor(s) whose proposal is determined to be the most advantageous to the Group (or each member of the Group). In rendering this decision, the following evaluation criteria will be utilized as a general guideline:

- (a) Product Functional Fit and Completeness
- (b) Product Technical Fit and Contemporariness
- (c) Vendor Profile, Financial Health and Experience
- (d) Installation Pricing and Ongoing Cost of Ownership
- (e) Installation Approach, Timeframe, Organization and Staffing
- (f) Partnership Proposal / Financing Options
- (g) Level of Risk and Uncertainty
- (h) Terms and Conditions
- (i) Completeness of the proposal and responsiveness to this RFP
- (j) Reputation of the vendor and its past relationship with members of the Group

The Group will utilize judgment and common sense in identifying the vendor finalist(s). Points will be awarded to assist the Group in rendering a decision through empirical analysis; however, the Group reserves the right to conduct other evaluations and measurements of vendor responses as may be required in order to render an informed and optimum decision. To be clear, each member of the Group may determine, among other possibilities, that it will select a different vendor or a different option with the same vendor or no vendor at all.

6. SCHEDULE OF EVENTS

The Group has established the following sequence of events and tentative schedule dates for this process.

6.1. Request for Proposal Distributed

6.2. Vendor Questions Due

Please submit all questions and clarification requests in writing via email to EC2006-008@enersource.com by, April 7th, 2006

6.3. Vendor Proposal Due

Two (2) original hardcopies, one (1) electronic copy, and seven (7) hardcopies of the proposal will be received until 3:00pm(EST), April 20th, 2006. Proposals received after this time will not be accepted. In the event of a discrepancy between the soft and hard copy information provided the hard copy information will be considered the correct information.

The proposal must be sealed and clearly marked. Proposals may be mailed or delivered in person to the following address:

Enersource Hydro Mississauga
c/o Attention: Purchasing Manager, Enersource Corporation
3240 Mavis Road,
Mississauga, Ontario L5C 3K1

Electronic proposals should be delivered on CD to the address above along with appropriate hardcopies.

On the outside of the sealed package, Vendors should prominently mark their full legal name and return address, the RFP title and number, and the address particulars (as set out above).

Email responses and unsigned submissions are NOT acceptable and will not be considered.

Each vendor is responsible for the actual delivery of its proposal to the address and location listed above and proposals will not be considered unless actually received at that location by 3:00:00pm Eastern Daylight Savings Time (the "Closing Time") on April 20th, 2006 (the "Closing Date") regardless of whether the proposals have been given to couriers, delivery services, Canada Post or employees or agents of the Group for delivery to the Group (as stated above). Proposals received after the Closing Time on the Closing Date will not be considered.

All proposals must identify RFP Number EC2006-008.

It will be the responsibility of the vendor to ascertain that it is in possession of a complete set of RFP documents and to thoroughly acquaint itself with those documents. It will also be the responsibility of the vendor to seek clarification to any part of this RFP. If the Group provides a response to any requests for clarification, such requests for clarification and the responses will be provided to all vendors. Vendors will check with the key contact by e-mail, concerning any discrepancies, omissions or additional information required. Vendors will not claim after submission of a proposal that there was any misunderstanding with respect to the conditions imposed by the RFP.

Neither the transmission of this RFP to a vendor nor acceptance or receipt of the proposal by the Group will imply any obligation or commitment on the part of the Group to enter into a contract or agreement of any kind in respect of any or all of the contents of this RFP.

This RFP does not oblige the Group to pay for any costs, of any kind whatsoever, that may be incurred by a vendor or any associated third parties, in connection with the proposal or in respect of any subsequent negotiations. All proposals and supporting documentation will become the property of the Group. If any part of the vendor's proposal is to be considered confidential, the vendor will clearly identify which portion of its proposal is to be considered confidential. Notwithstanding that the vendor may identify portions of its proposal as confidential, the Group may share and disclose the vendor's entire proposal to any and all project sponsors and to any employees, officers, directors or professional advisors, including technical advisors, of the Group who have a

need to know the vendor's proposal for the purpose of evaluating same and for any other reason relating to this RFP.

6.4. *Demonstration of Ontario Ready Software*

Following receipt of the RFP's, some or all of the vendors may be identified and asked to demonstrate the solution's ability to handle a representative sampling of transactions specific to the Ontario de-regulated environment. A script listing the processes to be demonstrated is included in Appendix C. The demonstration(s) will take place within 2 to 3 weeks after the close date for this RFP. Vendors will be provided a minimum of two weeks notice of the exact date of their scheduled demonstration, if they make the short list. Based on the outcome of the demonstration the Group may decide to limit its review of the RFP responses to software that performs satisfactorily in the demonstration.

6.5. *Vendor Business Finalist Identified*

The Group will conduct an evaluation of the proposals. Each evaluation will focus on examining the proposed solution in terms of the minimum requirements. Those vendors submitting a valid proposal which meets the Group's minimum requirements and initial evaluation criteria, as determined by the Group, may become business finalists and may move into the next stage of evaluation as determined by the Group in its sole discretion.

6.6. *Vendor Interviews and Further Demonstrations*

All business finalists will be invited to a two (2) day site visit to Toronto or Mississauga. Business finalists will be asked to spend the first day with the group selection team to answer questions regarding its proposal and to allow it an opportunity to ask clarification questions that will allow you to present a best and final proposal after this meeting, as appropriate. Following this interview the vendor will conduct a one (1) day on-site overview of the proposed software product solution. The first two (2) hours of this demonstration will allow the vendor to present their proposed solution to the Group. The remaining six (6) Hours will be a scripted demonstration of the product functionality. The vendor will be contacted to schedule the interview and product demonstration.

The Group evaluation team and key Group business and technical users will be in attendance. The demonstration is intended to be an overview focusing on key aspects of the system. The vendor will be expected to utilize the majority of the time demonstrating the customer system product and highlighting its selling points. Evaluation points, based on pre-established criteria by the Group, will be awarded for this demonstration.

6.7. *Vendor Reference Checks*

For all business finalists the Group evaluation team will contact vendor customer references by telephone. In addition the team may arrange at this time to visit vendor customer sites or corporate offices to further confirm and evaluate the proposed solution.

6.8. *Additional Discovery Work*

The Group evaluation team will conduct other discovery work as required to further evaluate vendor proposals. This may consist of additional interviews, demonstrations, site visits, and corporate office visits, benchmarking studies or other activities as required by the evaluation team to make an informed decision.

6.9. Vendor Finalist(s) Identified

Based upon the proposal responses, vendor interviews, product demonstrations, reference checks, checklist responses, and other discovery work, the Group will select at least one (but no more than two) vendors to proceed into detailed confirmation activities.

The procurement will remain open and in the event a solution is not reached with the vendor finalist(s), the Group will pursue confirmation activities with the second place vendor and so on until a final solution is achieved. A decision by one or more members of the Group to opt out at this stage may be declared to cease further review of a vendor selection based on the satisfaction level of the Group of the vendor responses provided.

All vendors submitting proposals will be notified regarding the Group's decision.

6.10. Vendor Finalist Confirmation

The vendor finalist is expected to conduct a comprehensive five (5) day detailed product design and discovery demonstration which will address the Group's requirements and supporting documentation.

The intent of this detailed product demonstration is to move beyond the "sales pitch" into a comprehensive review of system details. This will provide the Group with an opportunity to evaluate and validate the product, as well as, allow for the identification of required product modifications, and assist in defining a final project scope within which the vendor can refine cost estimates.

This review may include a usability test, which would provide users with hands-on use of the system. Additional working sessions may be conducted with the vendor to further refine the proposed solution.

6.11. Best and Final Offer

The selection process will allow the vendor to refine the implementation plan by becoming more familiar with functional requirements. This should result in a best and final offer.

6.12. Contract Discussion

It is expected that each member of the Group and the successful vendor will negotiate and execute its own comprehensive form of agreement setting out all of the terms and conditions that will apply to the provision of deliverables under this RFP.

To facilitate negotiations, the agreements could be based on an amended form of the successful vendor's standard legal documentation, as amended to reflect the negotiations of the parties.

The Group has the discretion to conduct contract negotiations in such manner as it will determine. It is anticipated that the Group will select two (2) vendors with whom the Group will consider contract negotiations. The Group may elect to negotiate with both concurrently or to select one vendor to commence negotiations with while the second vendor is held in abeyance pending the results of the negotiations with the first vendor.

Each vendor is to attach, in unlocked word format, an agreement or agreements that they wish to have the Group consider for negotiation purposes. The Group will consider whether the form of those agreements is appropriate for the basis of negotiations. The attachment of any such forms of agreements will not be considered to be acceptance by the Group, either as to form or substance, in whole or in part, of such agreement or agreements.

It is expected by the Group that the agreement will include the terms that follow. Each vendor will state in their proposal whether they agree to each of the following business terms being incorporated into the agreement. If the answer is not an unqualified yes, then a clear and specific alternative should be provided. Expressions such as “have negotiated these concepts in the past with other customers to our mutual satisfaction” or “subject to review/further review by our legal counsel” will not be considered as being clear and specific alternatives.

6.12.1. Limitation of Liability

A limitation of liability provision that will exclude the Group’s right to loss of profits or loss of revenue and will limit a claim for damages by the Group to the total value of the deliverables acquired by the Group (subject to a minimum one million dollar floor on damages). No limitation on liability would apply to: (i) breach of confidentiality obligations; (ii) breach of privacy obligations; (iii) injury to tangible property or persons due to negligence; (iv) intentional misconduct; (v) breach of applicable law; or (vi) the intellectual property indemnity. Except as set out above, no general limitations on Vendor’s liability will apply as to type or quantum of damages.

6.12.2. Intellectual Property Indemnity

The Group would be held harmless from damages suffered from, and defended by the successful vendor, in respect of, any third party intellectual property claim respecting the use of the deliverables in the manner contemplated by the Agreement with the Group. In the case of an injunction, the successful vendor will promptly, at its expense, either: (a) obtain for the Group the right to continue using the system provided under the Agreement; or (b) replace or modify the system to avoid a claim, provided that the replaced or modified system is substantially equivalent in function, speed, uptime and scalability. If an injunction is granted and not removed within ten (10) days, the Group will have the right to invoke termination and repayment of applicable funds on a straight line depreciated basis over 120 months from the date of acceptance.

6.12.3. Acceptance Testing

At the Group’s request, a specific acceptance testing procedure acceptable to the Group and the successful vendor will apply that will provide the Group with a reasonable period of time to confirm material conformance to performance parameters, processes and integration specifics outlined in their Agreement in all material respects in a production environment. Such testing may occur in phases to reflect the implementation of the applicable deliverables as part of a system. Such testing will include testing to confirm the ability of the system to work seamlessly. In respect of acceptance testing, a failure of the system to successfully pass acceptance testing, within ninety (90) days from the initial start of acceptance testing in a production environment, will allow the Group to

terminate the Agreement for cause and to receive a refund of all amounts paid under the Agreement.

6.12.4. Maintenance Term

Subject to early termination for cause (see below) and the right of extension by the Group for transition (see below), the maintenance and support services for the system will be available at the Group's request for the longer of: (i) eight (8) years from the date of final acceptance of the system; and (ii) when the Vendor is no longer providing support to any other customer in Canada. In any event, the Vendor will provide twenty-four (24) months' notice that maintenance and support services will no longer be available.

6.12.5. Termination for Cause

In respect of material breaches, the breaching party will have a sixty (60) day period to correct after notice thereof before the non-breaching party can terminate on notice. Material breaches can include a series of otherwise non-material breaches of key service level agreements that, over a period of time, culminate into a material breach for which notice can be provided.

6.12.6. Transition on Termination

Following termination, the Group may extend the Agreement by up to twenty-four (24) months immediately following termination (by expiry or for cause by either party) to migrate to a new solution in a seamless manner and the Group will pay the Vendor reasonable fees (being the fees in the Agreement, or in the absence of the applicable fee, at the Vendor's then standard published rates) for its services performed during any such transition period. The Vendor will provide all assistance reasonably requested by the Group including data conversion assistance, as applicable. The Group will have a perpetual right to use the system in their possession on termination provided that those elements of the system have been paid for.

6.12.7. Payment Schedules and Incentive Bonuses

The Vendors may suggest alternatives for payment schedules and incentive bonuses for purposes of future negotiations.

6.12.8. Service Level Agreements

Mutually agreed Service Level Agreements (SLAs) will be attached to the Agreement to measure all material forms of performance against specific standards. There will be set-offs against the fees on a prospective basis for a failure to meet the SLAs of a range of 5-25% of the applicable ongoing maintenance/service fees as well as a right to terminate if a recurring failure is a material breach of the Agreement and it is not corrected within the applicable period of time. As expected, both uptime and response times are of fundamental importance.

6.12.9. Warranties

Warranties will be provided by the Vendor as to skill of staff and the standard to which deliverables will perform as part of the overall system, including ongoing conformance with the applicable specifications. Deliverables are to be provided without

encumbrances and otherwise to be appropriate to perform to the applicable standard provided for in the Agreement. The warranties and remedies provided will apply equally to the entire system, including third party components provided by the Vendor.

6.12.10. Security and Confidentiality

The Vendor will agree to confidentiality provisions, and privacy provisions consistent with the Vendor's role in having access to the personal information of the Group's clients and otherwise consistent with the Group's obligations under the legislation of Ontario and Canada regarding protection of personal information and applicable laws in respect of personal information in its capacity as acting as an agent for the Group, and as a custodian of personal information, and an indemnity will be provided by the Vendor should the Vendor breach such provisions.

6.12.11. Law

Laws of Ontario and the forum of Ontario courts to apply.

6.12.12. Payments

Payments to the Vendor will be due on mutually agreed performance milestones with corresponding milestone completion dates (as opposed to calendar dates). One of the milestones will be the ability of the system to work seamlessly in the manner contemplated by the Agreement.

6.12.13. Source Code Materials Access

Title to applicable source code materials will be transferred to the Group if, and at the time, the related intellectual property rights are to be transferred to the Group under the Agreement. To the extent the applicable source code materials are not to be transferred to the Group under the Agreement, the successful vendor will agree to a source code trust agreement. This agreement will permit access to and use of the successful vendor's source code materials for the applicable software. Such source code materials would be held by a third party trustee in Ontario. The source code materials would include those materials reasonably required to allow the Group to independently maintain and support the applicable software. Release of the source code materials by the trustee would be triggered by the successful vendor's failure to cure a material breach of its software-related maintenance obligations or to otherwise make maintenance and support services available.

6.12.14. Proposal Documentation

At the Group's request, all proposal documentation presented by the Vendor in response to the Group's RFP, to the extent still applicable to the value proposition proposed by the Vendor, will be incorporated into the Agreement.

6.12.15. No Indemnity

The Vendor will not be seeking an indemnity from the Group.

6.12.16. Assignment Right

License and other rights obtained under the Agreement with the Vendor will be assignable by the Group on notice at no cost (other than, to the extent directly

applicable, implementation or like service costs related to any applicable movement of hardware, software or the like) to reflect reorganizations of the Group and/or the conduct of its IT/business process functions and/or the sale of the business to which the Agreement related. Any such assignment would require the assignee to assume, on a go forward basis, applicable obligations, including in respect of confidentiality, in respect of the Vendor's proprietary property.

6.13. Installation Plan

The Group will coordinate the development of an installation timetable in consultation with the selected Vendor. This timeline will address all aspects of the solution in preparation for its presentation and approval by the Board.

6.14. Approval Attained

The Group may make a decision regarding contract award 90 days after the release of this RFP.

6.15. Contract Awarded

Under the current plan, appropriate contract documents will be signed on or about May 10th, 2006.

6.16. Installation Start Up

Under the current plan, the Vendor will initiate project organization and startup activities no later than May 15th 2006.

7. TERMS AND CONDITIONS

The terms and conditions under which the Proposal will be made are detailed within this section. The Group views this RFP as the framework to be used by the Vendor in preparing and submitting the proposal.

It is important for the Vendor to become familiar with the paragraph items within this section, as they will prevail in the event of any discrepancies or differences between project related or contractual documents.

7.1. Basis for Proposal

Only information supplied by the Group in writing through the RFP contact should be used in the preparation of Vendor Proposals.

Only replies by formal addenda shall be binding. Oral and other interpretations or clarifications shall not be binding. Vendors must acknowledge all addenda by signing and including such documents in the Proposal.

7.2. Vendor Terms and Conditions

The Vendor must submit a complete set of any additional terms and conditions that they propose to have included in a contract negotiated with the Group.

7.3. *Disclosure of Proposal Contents*

Proposals shall be opened in a manner that avoids disclosure of the proposal content. Vendors are advised that the confidentiality of their proposals will be protected by the Group to the extent permitted by law.

7.4. *Late Proposals*

Proposals must be returned in sufficient time so as to be received at the specified location on or before the published proposal deadline date and time specified. Any proposal received after the time and date set for receipt of proposals will be late and will not be considered.

7.5. *Signing of Proposals*

The submission and signature of a Proposal shall indicate the intention of the Vendor to adhere to the provisions described in this RFP and to have the accepted terms of the Vendor's proposal and the RFP incorporated into any contract.

7.6. *Cost of Proposal*

This RFP does not commit the Group to pay any costs incurred by any Vendor in preparation and/or submission of a Proposal or for procuring or contracting for the items to be furnished under the RFP. All costs directly or indirectly related to responding to this RFP (including all costs incurred in supplementary documentation, meetings and demonstrations at the Group) will be borne by the Vendor.

Each Vendor will be responsible for all costs incurred in preparing or responding to this RFP. The Vendor agrees to bear all risks for loss, injury, or destruction of goods and materials (ordered or supplied as the result of the eventual contract) that might occur prior to delivery to the Group. Such loss, injury, or destruction will not release the Vendor from any obligations under this RFP or any resulting contract.

7.7. *Conflict of Interest, Non-Collusion Non-Lobbying*

The Vendor promises that its officers, employees or agents will not attempt to lobby or influence a vote or recommendation related to the firm's proposal response, directly or indirectly, through any contact with Board members, or employees of the Group between the proposed submission date and award of contract by the Group and that there will be no collusion with other proponents or fraud and no conflict of interest. Proponents are required to disclose in their proposals and on an ongoing basis thereafter any conflict of interest, real or perceived with respect to this RFP, any resulting contract, or the Group or any of its representatives.

7.8. *Ownership of Proposals*

All documents submitted in response to this RFP will become the property of the Group.

7.9. *Disqualification or Rejection of Proposals*

Vendors may be disqualified for any of the following reasons:

- (a) There is reason to believe that collusion exists among the Vendors;

- (b) The Vendor is in arrears on an existing Group contract;
- (c) Contractor has Defaulted on a previous Group contract;
- (d) The Vendor lacks financial stability;
- (e) The Vendor has failed to perform under previous or present Group contracts;
- (f) The Vendor has failed to adhere to one or more of the provisions established in this RFP;
- (g) The Vendor has failed to submit its Proposal in the format specified herein;
- (h) The Vendor has failed to submit its Proposal on or before the deadline established herein; or
- (i) The Vendor has failed to adhere to generally accepted ethical and professional principles during the Proposal process;

7.10. Withdrawal of Proposals

Proposals may be withdrawn by written or telegraphic notice received by the key contact at EC2006-008@enersource.com prior to the exact hour and date specified for receipt of Proposals. A Proposal also may be withdrawn in person by a bidder or his authorized representative, -provided his identity is made known and he signs a receipt for the Proposal, but only if the withdrawal is made prior to the exact Hour and date set out for the close of receipt for the Proposal.

7.11. Amending of Proposals

A Vendor must submit an amended proposal before the deadline for receipt of proposals. Such amended proposals must be complete replacements of a previously submitted proposal and must be clearly identified as such in the transmittal letter.

The Group will not merge, collate, or assemble proposal materials.

7.12. Exceptions to RFP Specifications

Although the specifications stated in the RFP represent the Group's anticipated needs, there may be instances in which it is in the Group's interest to permit exceptions to specifications and accept alternatives.

It is extremely important that the Vendor make very clear where exceptions are taken to the specifications and how the Vendor will provide alternatives. Therefore, exceptions, conditions, or qualifications to the provisions of the Group's specifications must be clearly identified as such together with reasons for taking exception, and inserted into the Proposal. If the Vendor does not make clear that an exception is being taken, the Group will assume the Proposal is responding to and will meet the specification as written.

Where the Vendor does not agree with the Group's terms and conditions, we require the proposal to enumerate the specific clauses that the Vendor wishes to amend or delete and suggest alternative wording. Any terms or conditions that the Vendor requires to

enter into a contract with the Group must be clearly identified and submitted with the Proposal.

7.13. Consideration of Proposals

Discussions may be conducted with responsible Vendors for the purpose of clarification to assure full understanding of the Vendors proposal. In conducting discussions, there shall be no disclosure of any information derived from proposals submitted by competing Vendors.

Until award of the contract is made by the Group, the right will be reserved to reject any or all proposals and waive technicalities, to re-advertise for new proposals, or to proceed with the work in any manner as may be considered in the best interest of the Group.

7.14. Termination

The Group reserves the right to cancel this RFP at any time.

7.15. No Obligation

This procurement in no manner obligates the Group or any member of the Group to the eventual rental, lease, or purchase of any software or services offered until confirmed by an executed written contract.

7.16. Award of Contract

The Group reserves the right to withhold final action on the Proposal for a reasonable time, not to exceed ninety (90) days after the date of opening proposals.

The Group reserves the right to abandon, without obligation to the Vendor, any part of the project, or the entire project, at any time before the Vendor begins any work authorized by the Group.

The award of the contract shall not become effective until the Vendor and the Group have executed the contract.

7.17. Execution of Contract

As previously noted, each member of the Group will enter into its own contract with the successful vendor(s), if any.

The Group will require the Vendor(s) to sign the necessary documents entering into the required Contract with the Group and to provide the necessary evidence of insurance as required under the contract documents.

No contract for this project may be signed by a member of the Group without the authorization of the applicable Board of Directors or a duly authorized representative of such member. No contract shall be binding on the Group until it has been approved by the applicable Board or otherwise in accordance with such member's corporate signing policy.

7.18. Scope of Insurance and Special Hazard

A Vendor shall carry insurance to provide adequate protection ("adequate protection" to be agreed to by the parties) for the Vendor and its sub-contractors, respectively, against damage claims that may arise from operations under this contract, whether such operations by the insured or by anyone directly or indirectly employed by the Vendor.

7.19. Contract Documents

This Request for Proposal, and any addenda or other documents as are made a part hereof, together with the final quotation of the successful bidder and the Group's written acceptance thereof, including the final agreement of the parties, shall comprise the Contract Documents. The Contract Documents shall constitute the entire agreement of the parties.

7.20. Price Sheets

The Vendor is required to provide the appropriate price sheets. All pricing will be in Canadian Dollars. The Vendor will attach a separate set of price sheets for each option proposed. Model price sheets are included in Appendix D. Vendors will adapt the price sheets as required providing the overall format is preserved. Additional comments should be noted at the foot of each sheet as required.

7.21. Functional Checklist

Vendors will be required to complete the appropriate functional checklist. The checklist will be used as an additional tool to grade the vendor's overall functionality. The vendor will indicate their scoring of functionality depending on whether the item is delivered with the base product or requires modification or requires time for configuration in the "Vendor Score" column. The vendor will note any explanations in the Comment column. If modification or configuration effort is required to deliver the functionality described, note the work effort required in the work effort column. Failure to complete in its entirety the section(s) the Vendor is submitting a bid on will result in a zero "0" score for the sections within the functional checklist not completed.

7.22. No Publicity or Promotion

Vendor will not make any public announcement or distribute any literature regarding this RFP any discussions relating to this RFP, any award or other results relating to this RFP, or otherwise promote itself in connection with this RFP. Further, no public announcement or the distribution of any literature are to be made by the successful Vendor in respect of any contract negotiations or the execution thereof unless otherwise agreed to by the Group or applicable member of the Group.

7.23. Intention To Bid

Vendor is requested to complete and return by facsimile to the key contact by April 5, 2006 the form attached as Appendix E entitled Notice of Intention to Respond. This will assist the Group in communicating with the vendor community and managing key stages of the procurement process. If Vendor declines to submit a proposal in respect to this RFP, then it will promptly return all RFP documents to the Bid Administrator. Please note that failure to return this form does not disqualify a supplier from submitting a proposal by the submission deadline.

7.24. Reserved Rights of THE GROUP (And each member thereof)

Each member of the Group reserves the right to:

- a) make public the names of any or all vendors;
- b) request written clarification or the submission of supplementary written information in relation to the clarification request from any vendor and incorporate a vendor's response to that request for clarification into the vendor's Proposal;
- c) adjust a vendor's scoring or reject a vendor's Proposal on the basis of
- d) a financial analysis determining the actual cost of the Proposal when considering factors including quality, service, price and transition costs arising from the replacement of existing goods, services, practices, methodologies and infrastructure (howsoever originally established);
- e) information provided by references;
- f) the vendor's past performance on previous contracts awarded by that member of the Group;
- g) the information provided by a vendor pursuant to the member of the Group exercising its clarification rights under this RFP process; or
- h) other relevant information that arises during this RFP process;
- i) waive formalities and accept Proposals which substantially comply with the requirements of this RFP;
- j) verify with any vendor or with a third party any information set out in a Proposal;
- k) check references other than those provided by any vendor;
- l) disqualify any vendor whose Proposal contains misrepresentations or any other inaccurate or misleading information;
- m) disqualify any vendor or the Proposal of any vendor who has engaged in conduct prohibited by this RFP;
- n) make changes, including substantial changes, to this RFP provided that those changes are issued by way of addenda in the manner set out in this RFP;
- o) select any vendor other than the Bidder whose Proposal reflects the lowest cost to the member of the Group or the highest overall score;
- p) cancel this RFP process at any stage;
- q) cancel this RFP process at any stage and issue a new RFP for the same or similar goods and services;
- r) accept any Proposal in whole or in part;
- s) discuss with any vendor different or additional terms to those contemplated in this RFP or in any vendor's Proposal;
- t) if a single Proposal is received, reject the Proposal of the sole vendor and cancel this RFP process or enter into direct negotiations with the sole vendor;

reject any or all Proposals in its absolute discretion; or,

negotiate in respect of any term or condition proposed by vendor in its Proposal, whether a business or legal term or condition or otherwise;

and these reserved rights are in addition to any other express rights or any other rights which may be implied in the circumstances and such member of the Group and its respective representatives or agents will not be liable for any expenses, costs, losses or any direct or indirect damages incurred or suffered by any vendor or any third party

resulting from the member of the Group exercising any of its express or implied rights under this RFP.

By submitting its Proposal, the vendor authorizes the collection by each member of the Group and its representatives of the information set out under (e) and (f) in the manner contemplated in those subparagraphs.

7.25. Requirement for a “Prime” Contractor

While any vendor may have subcontractors that form part of the Proposal, ultimately there will only be one vendor and such vendor will be wholly responsible for the Proposal and for all obligations and liabilities that flow from the Proposal, including through any agreement or agreements that may ultimately result from this procurement process.

7.26. Schedules

The following schedules are attached to and form part of this RFP:

Appendix A: Confidentiality Agreement;;
Appendix B: Functional Checklist;
Appendix C: Process Scripts;
Appendix D: Price Sheets; and
Appendix E: Notice of Intention to Respond.
Appendix F: Bidder Declaration

7.27. No Representations or Warranties

(a) Nothing in this RFP is intended to relieve Proponents in respect of the matters addressed in this RFP and to satisfy themselves independently regarding the accuracy and completeness of the information provided and the assumptions made in this RFP. The Group and its representatives and agents make no representations, warranties or conditions, either express or implied, in fact or in law, with respect to the accuracy or completeness of the information provided in this RFP.

(b) Without limiting the generality of the foregoing, the Group and its representatives and agents shall not be liable for any claim, action, cost, loss, damage or liability whatsoever arising from or related to any information or advice or any errors or omissions that may be contained in the RFP or any data, materials, or documents disclosed or provided to the Proponent pursuant to this RFP or otherwise.

7.28. No Damages

All costs, expenses, losses, damages and liabilities which may be incurred by the Proponents as a result of or arising out of the submission, acceptance or rejection of their Proposals, including the cost of preparing and submitting a Proposal, shall be borne entirely by the Proponents. The Group and its representatives and agents shall not be liable for any costs and expenses incurred by the Proponents or to reimburse the Proponents in any manner whatsoever or under any circumstances, including, without limitation, in the event of rejection of all Proposals or cancellation of this RFP.

Without limiting the generality of the foregoing, the Group and its representatives and agents shall not be liable, in contract, tort, restitution or any other legal theory, to a Proponent for any claim, action, costs, losses, damages or liability whatsoever arising from any act or omissions by the Group or its representatives or agents, including the rejection of any or all of the Proposals, the consideration or evaluation of any or all of the

Proposals, negotiations in respect to the Proposals, the selection of a Proponent, if any, or for any information or advice or any errors or omissions that may be contained in this RFP or any data, materials, or documents disclosed or provided to the Proponent pursuant to this RFP or otherwise.

8. SELECTION MILESTONES

Issue RFP:	March 27, 2006
Last date for vendor to submit notice of intent to bid:	April 5, 2006
Last date for vendor inquiries:	April 10, 2006
Last date for responses to vendor inquiries:	April 13, 2006
Last date for proposal submission:	April 24, 2006
Bidders Meeting	March 31, 2006 10:00 AM
Ontario market ready demonstration by vendor(s):	To be determined, approximately 6 weeks after RFP Issue date
Further demonstrations by vendor(s):	To be determined approximately 6 weeks after RFP Issue date
Announcement of decision:	On or about May 10, 2006

The above dates are subject to change at the sole discretion of the Group. In the event a change is made to these dates, the vendors will be informed by written addenda.

9. APPLICABLE LAWS

This RFP and any agreements resulting from this RFP, and the relations between the Group and any vendor, will be interpreted, governed and determined by the laws in force in Ontario.

10. Appendices

10.1. Appendix A Confidentiality Agreement

CONFIDENTIALITY AGREEMENT

Between

ENERSOURCE HYDRO MISSISSAUGA INC.

And

Enersource Corporation

And

TORONTO HYDRO-ELECTRIC SYSTEM LIMITED

And

Name of Proponent

(collectively, the “Parties”, and each of them individually, a “Party”)

WHEREAS Enersource Hydro Mississauga Inc. (“EHM”), Enersource Corporation (“EC”) and EHM and Toronto Hydro-Electric System Limited (“TH”) wishes to invite submissions of proposals from prospective proponents (“Proponents”, individually referred to as “Proponent”) to develop and implement a strategic supply agreement to supply a Customer Information Systems, and will issue a Request for Proposal (“RFP”) to describe the products and services required by EHM and TH (collectively, the “Proposed Services”);

AND WHEREAS in the process of issuing the RFP and providing information in connection therewith, EHM and TH may disclose information to the Proponents which is proprietary and/or confidential to EHM and TH (“Confidential Information” and as such term is more particularly defined below);

AND WHEREAS in the process of responding to the RFP and providing information in connection therewith, the Proponents may disclose Confidential Information to EHM and TH;

AND WHEREAS it is important to the Parties that the confidentiality of the Confidential Information be maintained;

Confidential Information is not to be shared with any other party without the prior written consent of
Enersource Hydro Mississauga Inc. & Toronto Hydro Electric System Limited

NOW THEREFORE WITNESSETH that in consideration of the mutual covenants contained herein and for other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the Parties covenant and agree as follows:

1. For the purpose of this Agreement:

(a) "Disclosing Party" shall mean the Party hereto that is disclosing Confidential Proprietary Information to the other Party; and

(b) "Receiving Party" shall mean the Party hereto that is receiving Confidential Proprietary Information from the other Party.

2. As used in this Agreement, the term "Person" shall be broadly interpreted to include, without limitation, any corporation, commission, company, partnership and individual.

3. In this Agreement the term "Confidential Information" means all information and data of any nature disclosed by a Disclosing Party to a Receiving Party, relating to:

(a) the purpose, nature and provisions of this Agreement;

(b) all information included in the RFP or furnished in connection with the RFP;

(c) all information included in the Proponent's Proposal or furnished in connection with the Proponent's Proposal;

(d) all information relating to the Proposed Services;

including without limitation, corporate information, financial statements, cost and expense data, electric distribution material data and all other information not generally ascertainable from public or published information, whether factual or interpretative, whether in written, oral, electronic or any other form, and whether or not identified verbally, or in writing by a Disclosing Party as "confidential".

4. Notwithstanding Section 3, this Agreement will not apply to the disclosure of any part of the Confidential Information which:

(a) is in the public domain at the time of the disclosure to the Receiving Party or which thereafter enters the public domain otherwise than by fault or a mission of the Receiving Party or by any breach of this Agreement;

(b) already in the possession of the Receiving Party prior to the date of disclosure by the Disclosing Party, as evidenced by the Receiving Party's documented records, and not received by the Receiving Party as a result of any prior relationship with the Disclosing Party or any of the Disclosing Party's predecessors;

(c) is lawfully obtained by the Receiving Party from a person other than the Disclosing Party or a representative of the Disclosing Party who is not otherwise bound by an obligation of confidentiality or is not otherwise prohibited from transmitting the respective information; or

(d) independently acquired or developed by the Receiving Party without violating any confidentiality agreement or other obligation of secrecy to the Disclosing Party.

5. The Receiving Party shall not, without the written consent of the Disclosing Party, disclose nor permit the use or disclosure of any Confidential Information to any Person other than those employed or retained by the Receiving Party or any of its affiliates who are actively and directly participating in the evaluation of this RFP, or development of a Proposal in response to same, or who otherwise need to know the Proprietary Information for the purpose of evaluating the Proposed Services (collectively, "Representatives"). The Receiving Party shall cause all such Representatives who have received Confidential Information to observe the terms of this Agreement.

6. Disclosure of any Confidential Information required by court order or any other law or regulation (including without limitation pursuant to any request under the Municipal Freedom of Information and Protection of Privacy Act) shall not be a breach of this Agreement provided that the Receiving Party shall, if permitted by such applicable law or regulation, notify the Disclosing Party in writing forthwith of the disclosure requirement in order to enable the Disclosing Party to take steps to resist or narrow the scope of the disclosure.

7. The Receiving Party and its Representatives shall not use the Proprietary Information for any purpose other than in connection with the review and assessment of the RFP, the review and assessment of the Proposed Services, the development of a Proposal in response thereto, and/or the execution of any agreement relating to the Proposed Services.

8. The Receiving Party shall be liable to the Disclosing Party for any breach of this Agreement including any breaches by its Representatives.

9. Upon the conclusion of the evaluation of the Proposals by EHM and TH, or receiving ten (10) days written notice from EHM or TH, a Receiving Party shall either return to EHM or TH (as applicable) forthwith all Confidential Information received without keeping duplicate copies of same, or destroy same and provide EHM or TH (as applicable) with an officer's certificate attesting to the destruction of such documents. This clause does not apply to any Proponent, if any, chosen by EHM and TH to provide the Proposed Services, and does not apply to EHM and TH with respect to such Proponent chosen, if any.

10. Although the Confidential Information provided in the RFP contains information which EHM and TH believes to be relevant for the purpose of evaluation of the RFP, EHM and TH does not make any representations or warranty as to the accuracy or completeness of such Confidential Information.

11. It is further understood and agreed that no failure or delay by a Party in exercising any right, power or privilege under this Agreement shall operate as a waiver thereof, nor shall any single or partial exercise of any right, power, or privilege under this Agreement preclude a Party from exercising any other or future right, power or privilege under this Agreement. No waiver of any provision of this Agreement shall be valid unless in writing and signed by an authorized officer of the Party waiving the protection of the provision in question, and such waiver shall not extend to any Provision, matter or occurrence not specified in such waiver by such Party. No waiver by one Party of a breach or failure to perform any obligation hereunder shall constitute a waiver or of any subsequent breach or failure to perform that or any other obligation under this Agreement.

12. No amendments, changes or modifications to this Agreement shall be valid unless agreed to in writing by the Parties.

13. This agreement shall remain in force for a period of three (3) years from the date hereof unless otherwise agreed to by the Parties, in writing.

14. This agreement shall enure to the benefit of the successors of the Parties hereto which for EHM and TH shall include, without limitation, affiliates of EHM and TH (as such term is defined under the Business Corporations Act (Ontario)) and shall be binding on the successors of both parties.

15. This agreement shall be governed and construed in accordance with the laws of Ontario and the laws of Canada as applicable therein. The Parties hereto irrevocably at torn to the non-exclusive jurisdiction of the courts of Ontario and courts competent to hear appeals therefrom.

16. This Agreement may be signed in counterparts and delivered by facsimile, each of which shall be deemed an original and all of which shall constitute one and the same agreement.

IN WITNESS WHEREOF this Confidentiality Agreement is executed on the _____ day of _____, 2006.

NAME OF PROPONENT

Per: _____
Name:
Title:

I/we have authority to bind the Corporation.

Per: _____
Name:

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Enersource Hydro Mississauga Inc. & Toronto Hydro Electric System Limited

Title:
I/we have authority to bind the Corporation.

ENERSOURCE HYDRO MISSISSAUGA INC

Per: _____
Name:
Title:

I/we have authority to bind the Corporation.

Per: _____
Name:
Title:
I/we have authority to bind the Corporation.

ENERSOURCE CORPORATION

Per: _____
Name:
Title:
I/we have authority to bind the Corporation.

Per: _____
Name:
Title:
I/we have authority to bind the Corporation.

TORONTO HYDRO-ELECTRIC SYSTEM LIMITED

Per: _____
Name:
Title:

I have authority to bind the Corporation.

10.2. Appendix B - Functional Checklist

Functional Checklist

Table 10.2.1. Scoring Method

Functions & Features Checklist

Each vendor will respond to each function / feature. Each vendor will use the scoring categories below in each of the function and features in this document.

Points	Weight	Description
25	Off-The-Shelf	The function is provided in the base product. No modification is required.
20	Roll Into Base	The function will be developed and placed into the base at no cost by release date.
10	Under Development	The function will be developed and placed into the base at no cost within 12 months of release date.
5	Modification	The function is proven. It will reside outside of core as a modification or third party bolt-on.
1	Enhancement	This requires a specific enhancement to be developed for the customer which may or may not be rolled into base.

Table 10.2.2. Account Management

1.0 ACCOUNT MANAGEMENT				
Item	Function / Feature	Vendor Score	Comments	Work Effort
1.1	Review the Account Entity			
1.1.1	Account Identification and Access			
1.1.1.1	When a customer enters into an agreement for service the system generates a non-significant account number with a flexible structure (customer ID - premise ID)			
1.1.1.2	Specification of several account keys with browsing capability on partial keys. The following access paths have been identified:			
1.1.1.3	> Customer Name			
1.1.1.4	> Customer Service Address			
1.1.1.5	> Customer Mailing Address			
1.1.1.6	> Customer Account Number			
1.1.1.7	> Meter Number			
1.1.1.8	> Equipment Number			
1.1.1.9	> Product Number			
1.1.1.10	> Land Parcel Number			
1.1.1.11	> Standard Industry Code (SIC)			
1.1.1.12	> Customer ID			
1.1.1.13	> Telephone Number			
1.1.1.14	> Two Pieces of ID			
1.1.1.15	> Drivers License Number			
1.1.1.16	> Service Order Number			
1.1.1.17	> Business Name			
1.1.1.18	> GIS X,Y Coordinate			
1.1.1.19	> By Old Account Number from previous System(s)			
1.1.1.20	> Search by Soundex for example: Smith and Smyth			
1.1.1.21	> By cycle route and walk. (Walk is the premise)			

1.1.1.22	> Indicator if account holder is owner or tenant of service address currently associated with.			
1.1.1.23	> Tax Roll Number - Municipal #			
1.1.1.24	> Duns Number - Credit Rating			
1.1.1.25	> Type of Business - INC - LTD			
1.1.1.26	> Info from Art of Incorporation			
1.1.2	Account Status			
1.1.2.1	On-line notification and statusing of the customers account and any "alarm" items associated with the account.			
	System will provide the following statuses of a customer account:			
1.1.2.2	> Active			
1.1.2.3	> Inactive			
1.1.2.4	> Final Billed			
1.1.2.5	> Disconnected for non-payment / non-signed / inspection and permitting			
1.1.2.6	> Write-off			
1.1.2.7	> Hot listed Address / Premise			
1.1.2.8	> Disconnected by Service - Elec / Water Separate			
1.1.2.9	System will provide the ability to create user-defined account statuses. (Pending Status)			
1.2	Account Types			
1.2.1	Master Accounts			
1.2.1.1	A single master account (or customer) can be established with several sub-accounts.			
1.2.1.2	A single master account will be responsible for the receivables of the sub-accounts.			
1.2.1.3	Allows establishment of a master account where the master does not have a premise in the Utility's service area. (Hot water tank outside service area)			
1.2.1.4	System provides the history of master/sub-accounts relationships on-line.			

1.2.1.5	System supports master summary account handling and total relationship management from account set-up, establishing deposits, processing payments, delinquency processing, and write-off processing.			
1.2.1.6	System maintains credit histories of subordinate accounts independently from the master account credit history.			
1.2.1.7	A sub-account can easily be associated/disassociated with a master account.			
1.2.1.8	Establish a joint account with two or more persons liable for the bill			
1.2.1.9	Master by Service - Elec / Water			
1.2.2	Temporary Accounts			
1.2.2.1	Support a premise rental agreement			
1.2.2.2	Support for temporary customers at Christmas tree lots, construction sites, seasonal, water, etc.			
1.2.2.3	Support for temporary or dummy accounts.			
1.2.3	Account Transfer			
1.2.3.1	System provides the ability to transfer service from one customer account to another based on user defined transfer date including retroactive dates.			
1.2.3.2	System generates a notification document to the third party when a service is transferred or disconnected. (Landlord notification)			
1.2.3.3	System will use user defined or system generated last meter readings for "transfer from" and/or "transfer to" service. (Within a specific window of time, user defined)			
1.2.3.4	System transfers bill options, rate assignment, and bill frequency to the new account.			
1.2.3.5	System optionally generates a summary letter to be given or sent to customer/landlord for confirmation of service transfer.			

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1.2.3.6	System allows the user to group multiple accounts/premises to be closed or transferred to another account.			
1.2.4	Account Close			
1.2.4.1	System provides the ability to close an account without a transfer of service.			
1.3	Account Offerings			
1.3.1	Service Offerings			
1.3.1.1	All available services can be reviewed at the premise on-line.			
1.3.1.2	Identification of the services available within a user inputted street block range.			
1.3.1.3	Provides a mechanism to open all or multiple services for the account. These services can be connected via a single conversation with the customer.			
1.3.1.4	Ability to open specific services without opening others.			
1.3.1.5	Review of applicable rates/pricing with the customer for the services they are interested in.			
1.3.1.6	Recording of the customers service choices and selected rate/pricing plans.			
1.3.1.7	Ability to change all mailing address with associated sub (only keying once)			
1.3.2	Program Offerings			
1.3.2.1	All program offerings which may be relevant to the customers situation can be reviewed on-line.			
1.3.2.2	Review financial aspects of the programs the customer is interested in.			
1.3.2.3	Establish customer on a special early payment discount program.			
1.3.2.4	Establish customer on a special senior citizen discount.			
1.3.2.5	Establish customer on levelized, equalized or average payment plan.			

1.3.2.6	Establish Landlord arrangement for automatic connection and disconnection when tenant moves out.			
1.3.2.7	The system needs to support the possibility of "continuous billing" at a property; which means specifically that a property must always have an active account to bill regardless if the property is vacant, demolished, meter removed or shutoff			
1.3.2.8	The system must also support the possibility that one customer account is only associated with a single property record			
1.4	Account Views			
	On-line access to account information from a consolidated view to a detailed view. Account views are provided by:			
1.4.1	> Consolidated view of a master account. All sub-accounts will be included.			
1.4.2	> Consolidated view of a customer with multiple accounts. All accounts are billed separately.			
1.4.3	> A service view (electric, waterheaters etc.)			
1.4.4	> A service point view (e.g., electric service point 1, electric service point 2, water service point 1, water service point 2, etc.)			
1.4.5	> A meter, product or equipment view.			
1.4.6	On-line access to a similar view of the bill as it was produced and distributed to the customer. Bill information for the past "24" months should be available on-line.			
1.4.7	On-line access to an exact image of the bill as it was produced.			
1.4.8	On-line access to the past "3" years of customer consumption history, read dates, reading, and bill amounts displaying the most recent information first.			

1.4.9	On-line view of account consumption/usage history by meter or by service.			
1.4.10	On-line access to total combined consumption across multiple meters and multiple registers.			
1.4.11	On-line view of account payment history. (Want 3 years of payment history)			
1.4.12	On-line view of how the payment allocation was applied.			
1.4.13	On-line view of payment transactions including up to the minute postings. Processing is not required to view the payments made.			
1.4.14	On-line bill hover feature to define field. (No external help necessary.			
1.4.15	On-line view of deposit information including an estimated refund date.			
1.4.16	On-line view of a customer's loans including outstanding balance, interest etc.,			
1.4.17	On-line view of account billing history.			
1.4.18	On-line view of a statement of account.			
1.4.19	On-line access to the past "3" years of customer account transactions (including adjustments, payments).			
1.4.20	On-line view of an accounts credit history or credit score.			
1.4.21	On-line view providing an "Account at a glance". Information would include: A/R, deposit info, adjustments, payments, credit history, etc.			
1.4.22	Print a formatted statement of account for example: billing / consumption / payment history for the customer displaying the most recent information first.			
1.4.23	On-line access to historical service and meter orders for a premise.			
1.4.24	On-line access to pending service and meter orders for an account.			

1.4.25	On-line access to charges and fees pending and not yet billed (e.g., initiation fees, deposits).			
1.5	Account Processing			
1.5.1	Capture customer application for service information.			
1.5.2	On-line review and confirmation of service address information. Service address is verified in the premise database.			
1.5.3	On-line identification of previous charge-off or bad debt amounts. Including potential on-line skip tracing based upon specified search keys (name, driver's license, tax ID).			
1.5.4	Establish responsible third party and contact information.			
1.5.5	Establish customer mailing address specific to each account.			
1.5.6	Provide temporary mailing address specific to each account.			
1.5.7	Customer tax or fee exemption status and re-certification dates. (Produce a report and customized letter)			
1.5.8	Customer can request multiple bills sent to a single mailing address.			
1.5.9	Ability to send duplicate bills to multiple 3rd party customer entities.			
1.5.10	On-line entry of new forwarding address onto an account and have the address reflect on the account in a user defined period of time. Customers can indicate the date of when the address will become valid.			
1.5.11	Support user requests to identify and list accounts by account classification or category, for example by: S.I.C. code, Trade Class, Postal Code Area, Life Support Customers, Large Volume Users, etc.			

1.5.12	Provide a quarterly or yearly statement to customers detailing: volume usage summary, power usage summary, and other historical accounts receivable data.			
1.5.13	Allow a customer's meter test info (status, test results, etc.) to be incorporated into or accessible from the system.			
1.5.14	Track history of rate determinants for rebilling by service. Multiple rate changes can be accommodated when rebilling a service.			
1.5.15	Provide the ability to combine consumption from multiple account / locations for a single customer to calculate the bill			
1.5.16	Conduct mass changes across accounts, customer records, or premises. Postal code changes.			
1.5.17	Statement of payments for accounts who have contributed to various contribution programs. Provide for the printing of the customers total contributions by program once a year on the bill.			
1.6	Account Adjustments			
1.6.1	On-line of adjustment to a bill on a line item basis as opposed to an entire bill.			
1.6.2	System will assure that when billing adjustments are made, all appropriate GL transactions will be applied.			
1.6.3	On-line adjustment of all charges, fees, surcharges, taxes, and refunds on a customer account for current and "3" previous months. For example: consumption charges, customer charges, miscellaneous fees.			

1.6.4	On-line review and approval of all adjustments meeting specified review parameters (user determined and table driven). Prior to an adjustment applying to an account it must be reviewed.			
1.6.5	Provide the ability to adjust consumption, rebill the account, and have appropriate readings and revenue adjusted accordingly without making manual entries to the G/L. (Cancel/rebill). (Should be security around this)			
1.6.6	Apply adjustments to accounts which have been written-off.			
1.6.7	Provide the ability to reverse transactions where a customer has been connected / disconnected/transferred to/from an address in error. Charges have been applied to the bill in error. Mechanism will be provided to easily rectify.			
1.6.8	Supports the tracking, assignment, resolution, and reporting of all adjusted customer billing and service disputes.			
1.6.9	Tax and Penalty Exemptions			
1.6.9.1	Provide tax exemptions for a specific tax or taxes.			
1.6.9.2	Provide tax exemptions across all taxes.			
1.6.9.3	Provide tax exemptions based on an amount and a percentage.			
1.6.9.4	Provide tax exemptions with an expiration date.			
1.6.9.5	System automatically generates a notification document to the customer when a tax exemption date has been exceeded.			
1.6.9.6	Provide penalty exemptions for a specific penalty			
1.6.9.7	Provide penalty exemptions across all penalties.			

1.6.9.8	Provide an expiration date assigned to the penalty exemption.			
1.6.9.9	System automatically generates a notification document to the customer when a penalty exemption date has been exceeded.			
1.6.9.10	Provide reporting on tax and penalty exempt customers.			
1.6.9.11	Water Service Exempt - Sundry charges - taxable - tax exempt parts of all of the charges in			

End of Section

Table 10.2.3. Billing Management

2.0 BILLING MANAGEMENT				
Item	Function / Feature	Vendor Score	Comments	Work Effort
2.1	Billing Triggers			
2.1.1	Cycle Driven Billing Schedule			
2.1.1.1	Customer accounts are assigned a date driven primary billing cycle, all accounts within a cycle will bill on a schedule day of the month. The billing schedule is easily changed with the ability to combine multiple cycles or to delay billing of a cycle.			
2.1.1.2	The cycle billing schedule is easily changed with the ability to combine multiple cycles, segregate cycles, accelerate or delay the billing of a cycle.			
2.1.1.3	A billing cycle will not be delayed if all reads are not received for the cycle. Billing will be run for those accounts which have recorded usage or the system will attempt to estimate those who do not have valid readings. All others will be held.			

	Accommodate billing for customers of various rate classes, usage volumes, number of dwelling units, rate schedules, etc. For example:			
2.1.1.4	> Residential Single-family dwelling (owned or rented)			
2.1.1.5	> Residential Multi-family dwelling (individually metered/non-metered buildings)			
2.1.1.6	> Residential Master meter--ranging from multi-family individual units, to trailer parks w/laundry facilities.			
2.1.1.7	> Commercial Customers			
2.1.1.8	> State Government			
2.1.1.9	> County Government			
2.1.1.10	> Industrial Firms			
2.1.1.11	> Wholesale Customers			
2.1.1.12	> Transmission Customers			
2.1.1.13	> Federal Government Agencies			
2.1.1.14	> Other Utilities			
2.1.1.15	> Other Cities			
2.1.1.16	> City Government			
2.1.1.17	Easily modify a single account's billing cycle, and allow for mass billing cycle changes to groups of accounts.			
2.1.2	Date Driven Billing Schedule			
2.1.2.1	Provide for billing of an account based upon a specified date. Account will be billed the same date each period.			
2.1.3	Event Driven Billing Schedule			
2.1.3.1	The system allows for billing of all accounts for which usage/consumption has been received regardless of the primary billing cycle the account belongs to.			
	Accounts meeting the following conditions will be allowed to bill whenever their readings are received:			
2.1.3.2	> Rebill an Adjusted Bill			
2.1.3.3	> Final Bill			

2.1.3.4	> Billing Due to Late and Early Reading			
2.1.3.5	> Special Billings			
2.1.3.6	> Cancel / Rebills for consumption corrections			
2.2	Consumption			
2.2.1	Time Based Billing			
2.2.1.1	Billing based upon a period of time. Every 30, 45, 60 days service is billed, consumption is not considered.			
2.2.2	Volume Based Consumption			
2.2.2.1	Calculate consumption for multiple meter exchanges on an account during a single billing period. System will accommodate a set reading and an out reading.			
2.2.3	Real Time Consumption (15 minute intervals)			
2.2.3.1	Calculate consumption based upon real-time read intervals.			
2.2.3.2	Accommodate an interface to MVRs/MV90 software. (Itron)			
2.3	Consumption Validation & Estimation			
2.3.1	Validation Methods			
2.3.1.1	Validate consumption based upon user-defined estimating guidelines and algorithms.			
	System estimating guidelines may include the following:			
2.3.1.2	> Average consumption for the past three years. (User defined)			
2.3.1.3	> Average of previous two months. (User defined)			
2.3.1.4	> Consumption used during the same time last year and the year before if necessary.			
2.3.1.5	> Degree days			
2.3.1.6	> Different parameters by account type			

2.3.1.7	> High/low parameters for demand quantities			
2.3.2	Estimating			
2.3.2.1	Estimate an entire reading route or billing cycle.			
2.3.2.2	View customers with greater than "x" number of estimated bills over "x" period of time.			
2.3.2.3	The bill estimation calculation should take into account the number of days the customer has been receiving service during the billing period. New service customers and final billed customers.			
2.3.2.4	Capability of excluding customers from estimation for example large commercial customers.			
2.3.2.5	Capability of estimating consumption based on defining YYMMDD FROM-TO periods for a summer and winter period kWhs per day			
2.3.2.6	Capability of automating final bill estimates based on a set of rules to determine if the final bill can be estimated or an actual meter reading is required.			
2.4	Consumption Usage			
2.4.1	Calculate consumption based upon readings or passage of time.			
2.5	Pricing			
2.5.1	Utilization of rate schedules and pricing plans.			
2.6	Billing Periods			
2.6.1	Flexible Periods			
2.6.1.1	Allow for flexibility in establishing the billing period. Periods can consist of more than one month.			
2.6.1.2	Accommodate billing of accounts on a bi-monthly, monthly, quarterly, semi-annual, and yearly basis.			
2.6.2	Proration			

2.6.2.1	Calculate the total summer and winter days for the billing period. Billing rates will be adjusted accordingly.			
2.6.2.2	Prorate an active account that is billing for less than "x" days or greater than "x" days.			
2.6.2.3	Exclude proration of specific charges, fees, deposits, etc.			
2.6.2.4	Prorate a charge or credit to the customer's account based upon the number of days in the billing period.			
2.7	Billing Calculations			
2.7.1	Bill Abilities			
2.7.1.1	Ability to bill in advance for service			
2.7.1.2	Ability to bill in arrears for service			
2.7.1.3	Ability to bill for net metering (secondary meter consumption added/subtracted from primary meter) on same or different accounts			
2.7.1.4	Ability to bill based on various calculations including time of use, tiered, various blocks, interval, etc			
2.7.1.5	Ability to bill based on Totalized situations (multiple meters consumption totalized to one billing quantity)			
2.7.1.6	Ability to calculate charges based on various meter registers (i.e. co-gen meters with both positive and negative registers)			
2.7.1.7	Ability to automatically process Global Adjustment transactions			
2.7.1.8	Ability to process MPMA, OPC, monthly forms (1598), spot and fixed pricing tracking and reporting			
2.7.1.9	Provide ability to bill non-service charges. (i.e. Engineering and Sundry invoicing, miscellaneous charges, etc) to customers without utility account			

2.7.1.10	Provide sundry and engineering invoicing module allowing users to select transaction types from pick lists with default values. Posting of transactions would require checking and approval security levels.			
2.7.1.11	Provide ability to bill customers based on their requested date--not driven by billing cycle			
2.7.1.12	Provide functionality to bill non-utility charges monthly (or as needed) to customer accounts. These include retiree benefits, monthly service charges (building rent, etc), instalment billing			
2.7.3 Bill Electric Services				
2.7.3.1	Bill for general electric service based upon previous and current meter readings. Rates are based on a customer charge, metered rate based on consumption, and a monthly adjustment clause (purchase power charge).			
2.7.3.2	Bill electric customers for both KQ, KVAR, KW or KVA demand charges and/or time-of-use rates. (Primary discounts) (Bill based upon special negotiated services)			
2.7.3.3	Bill private off street lighting.			
2.7.3.4	Bill customers based upon special negotiated service contracts			
2.7.3.5	Bill customers based upon defined demand read. (Need the flexibility to use a fixed demand)!			
2.7.3.6	Bill customers based upon unbundled service contracts including separate items for transmission charge, meter charge, customer charge, etc.			
2.7.3.7	Bill customers based upon standby service contracts.			
2.7.3.8	Bill customers based upon co-generation service contracts.			

2.7.3.9	Bill customers based upon firm and interruptible service contracts			
2.7.3.10	Bill customers for non-portfolio power service. Items that are not usually considered part of the Utility's electric service offerings.			
2.7.3.11	Bill customers for energy efficiency services.			
2.7.3.12	Water - Meter / Satellite - Aux Meters			
2.7.3.13	Bill price protected customers before market pricing is available.			
2.7.3.14	Able to bill negative consumption for net metering situations			
2.7.3.15	Able to bill net consumption for net metering situations			
2.7.4	Bill Products			
2.7.4.1	Bill customers based upon merchandise sales/rental/lease contracts. Merchandise could include appliances, non-energy products.			
2.7.5	Bill Equipment			
2.7.5.1	Bill customers based upon utility equipment sales/rental/lease contracts. Equipment could include load devices, surge suppressers, solid waste containers.			
2.7.6	Bill Programs			
	Bill customers who participate in programs for example:			
2.7.6.1	> Average or Equalized or Levelized Payment Plans			
2.7.6.2	> Low Income or Senior Citizen Plans			
2.7.6.3	> Automatic Bank Drafting Payment Plan			
2.7.6.4	> CCCF (Customer donations towards assistance program)			
2.7.7	Subscription Billing			
2.7.7.1	Bill, collect, remit, and track accounts for another company to read meters and bill. A check will be remitted to the other company minus a service fee.			

2.7.8 Budget Billing				
2.7.8.1	System provides for levelized billing. System recalculates the monthly payment amount for levelized billing by calculating the average monthly consumption over the past user-defined historical period resulting in a varying monthly payment.			
2.7.8.2	System provides for budget billing. System calculates and establishes a consistent monthly payment that is founded upon an anticipated consumption over a user defined period.			
2.7.8.3	Budget amount is reviewed and the amount adjusted once per year, new customers are reviewed semi-annually.			
2.7.8.4	System provides for average billing. System calculates the average billing amount over a specified period of past billing, and establishes as the monthly bill amount for a period of time.			
2.7.8.5	System automatically notifies user of budget billing accounts that are delinquent and collect if they don't have a credit amount.			
2.7.8.6	Remove customer from equal payment program after the "x" consecutive or non-consecutive missed payment in a "x" month period.			
2.7.8.7	If an equal payment is skipped, the next month's bill should reflect the equal payment in arrears in addition to the current month's equal payment amount.			
2.7.8.8	System supports the automatic generation of notice to customer that they are subject to removal from budget billing or that the budget period is ending.			

2.7.8.9	System performs automatic re-calculation of budget billing payment amount on demand or at user defined interval.			
2.7.8.10	System supports dividing the variance or "true up" amounts by the number of budget plan periods and adds the result to the newly computed budget amount.			
2.7.8.11	System can apply the variance or "true up" in a single lump sum to the next bill.			
2.7.8.12	System provides user on-line indication that an account is on a billing program with the ability to drill down to a display of the detail data associated with the billing.			
2.7.8.13	Allows for budget billing of metered, non-metered, and meter related services.			
2.7.8.14	System provides a process to report on budget accounts to show how these programs are impacting the Utilities cash position.			
2.7.8.15	System allows for the Utility to define eligibility restrictions that must be met for budget billing and allows users to apply or override restrictions on sign-up. Restrictions may include credit history, amount of delinquency, etc.			
2.7.8.16	System allows the user to define the number of periods and starting month for the budget billing.			
2.7.8.17	Late payment charge is added to a delinquent budget amount			
2.7.8.18	Flexibility to vary budget billing parameters by company			
2.7.8.19	Ability to offer level, average or budget bill.			
2.7.8.20	Budget billing will accommodate changes in rates. Budget amount must change to reflect rate change.			
2.7.9	Fees, Charges, Taxes, Surcharges			

	Provide the ability to bill various fees, charges, taxes, and surcharges. For example:			
2.7.9.1	> Late payment charges for past due amounts			
2.7.9.2	> Security deposit instalment amount			
2.7.9.3	> Refund of deposit and credit balances on accounts			
2.7.9.4	> Returned check fees			
2.7.9.5	> Initiation/Collection/Reconnect fees			
2.7.9.6	> City/County/State/utility tax			
2.7.9.7	> Service labour amounts for work performed by a service crew			
2.7.9.8	> Service charges including parts and after hours fees			
2.7.9.9	> Meter tampering penalties			
2.7.9.10	> Switching fee			
2.7.9.11	> Credit card/Energy Audit/Misc. fees			
2.7.9.12	> Load profile data recorder charge			
2.7.9.13	> Property cleanup charges			
2.7.9.14	> Fee for cutting the street			
2.7.9.15	> Prepayment for additional charges			
2.7.9.16	> create a new rate establishes a fixed charge			
2.7.9.17	Automatic refund of transactions at time of final billing (i.e. deposits on file)			
2.7.10	Bill Water Services (and other service types)			
2.7.10.1	Bill for general water service based upon previous and current meter readings. Rates are based on a customer charge, metered rate based on consumption, and a monthly adjustment clause (purchase power charge).			
2.7.10.2	Bill water customers based on various consumption values (cubic meter and cubic foot).			
2.7.10.3	Bill flat rate water services			

2.7.10.4	Bill customers based upon special negotiated service contracts			
2.7.10.5	Bill sub services (i.e. sanitary and/or storm sewer charges), consumption based and flat rate			
2.7.10.6	Bill customers based upon unbundled service contracts including separate items for transmission charge, meter charge, customer charge, etc.			
2.7.10.7	Bill customers for non-portfolio power service. Items that are not usually considered part of the Utility's electric service offerings.			
2.8	On-line Account Billing			
2.8.1	Provide an on-line bill calculation and generation feature. Bill will calculate immediately for printing, over night processing is not required.			
2.8.2	Accommodate back billing for "x" number of months with an appropriate start and end date. Charges were not applied to a customer's account, back billing will retrieve the new start date for a service.			
2.8.3	What-If Billing			
2.8.3.1	Provide for the identification and modification of billing factors to provide a "what-if billing function". What if my rate changed? What if my consumption changed? Etc.			
2.8.3.2	Provide a printed quotation to the customer for requested services, products and programs.			
2.8.4	Adjusted Billing			
	Accommodate an on-line cancel/rebill (adjustment) process which will allow cancelling, adjusting, and rebilling the accounts for "x" previous billing periods for changes in any billing component including rates and usage. Examples include:			
2.8.4.1	> Misread Meter			

2.8.4.2	> Over/Under Estimated Read			
2.8.4.3	> Meter/Equipment/Service Change			
2.8.4.4	> Customer Bankruptcy			
2.8.4.5	> Slow/Fast Meter			
2.8.4.6	> High Bill Investigation			
2.8.4.7	> Miscellaneous			
2.8.4.8	Cancel/Rebill process may be applied to an entire bill, line item, or to a specific service.			
2.8.4.9	Systems provide the ability to lock someone out of account if someone else is currently working on that account.			
2.8.4.10	System provides the ability to cancel only those services selected by the user and then rebill the selected service(s) only. The rebill includes all other unchanged items that were on the original bill and in the same format as the original bill.			
2.8.4.11	System generates appropriate G/L entries when the cancel/rebill process is performed.			
2.8.4.12	Maintain past and present usage billed to each rate schedule for a customer account to support the need for reconstructing or rebilling the customer for previous periods.			
2.8.4.13	Produce and print a corrected bill which reflects adjustments made to previous period consumption for "x" previous periods.			
2.8.4.14	Provide a corrected current bill which reflects adjustment made to a previous period's bill.			
2.8.4.15	Accommodate non-meter related consumption adjustments such as security light changes for back billing, etc.			
2.8.4.16	Ensure that the entire cancel/rebill process is completed avoiding unbilled consumption			

2.8.4.17	Provide mechanism for user to cancel transaction without posting to account--verification step			
2.8.4.18	Ability to bill, cancel and re-bill based on various customer billing options. These include RPP, NSLS, Retail and SSS combinations. All combinations are expected (and have occurred). System should be able to identify each billing type and adjust accordingly			
2.9	Billing Types			
2.9.1	Account Bill			
2.9.1.1	Combine usage for multiple metered and non-metered service points into a single consolidated account bill. System will combine an unlimited number of meters on a single bill.			
2.9.1.2	Accommodates billing for all services on a single bill.			
2.9.1.3	Provide aggregate billing of multiple meters at a single location; combine demand from individual demand meters by individual time intervals to derive the peak demand for the entire account. (Conjunctive Billing)			
2.9.2	Summary or Master Bill			
2.9.2.1	Combine multiple accounts into a single summary or master account bill.			
2.9.2.2	System allows the master account the option of receiving a billing summary and/or by detail showing the usage and charges, by service, being billed to each sub-account.			
2.9.2.3	System issues the master summary bill in accordance with the master account billing cycle. All sub-accounts that are billed on cycles other than the masters shall be indicated as unbilled until the master account is billed.			

2.9.2.4	The master account will receive a summary bill with all detail bills; detail bills can be easily separated and sent to the individual accounts.			
2.9.3	One-Time or Miscellaneous Bill			
2.9.3.1	Produce a one-time miscellaneous bill to a current customer. One-time bill is produced in addition to a normal cycle bill.			
2.9.3.2	Produce a one-time miscellaneous bill to an individual that is not a Utility customer for property damage, merchandise, etc.			
2.9.3.3	Produce a one-time miscellaneous item on the cycle bill.			
2.10	Bill Production			
2.10.1	Bill Formatting			
	bill print creates an output file for a bill print outsourcer. (Kubra)			
2.10.1.1	Flexibility in combining line item charges or separating item charges for bill printing.			
2.10.1.2	Flag charges to not appear on the bill. Adjustments or charges made in error that the Utility does not want the customer to view.			
2.10.1.3	Bill is printed with an identifier of the type of bill including if it is corrected, initial, closing, regular, delinquent, estimated, and bank draft.			
2.10.1.4	The date and meter readings at the beginning and at the end of the period for which the bill is rendered.			
2.10.1.5	The beginning and ending dates for the service. Non-metered services that are not consumption based.			
2.10.1.6	The number (including zero or "no usage") and kind of units metered (e.g., kilowatt hours, kilowatts of electricity).			
2.10.1.7	Display the total amount due in an easy definable place on the bill.			

2.10.1.8	The total amount due plus amount of penalty if not paid by due date. The penalty amount can be viewed as a separate line item.			
2.10.1.9	The date by which the Customer must pay the bill in order to avoid penalty or termination proceedings.			
2.10.1.10	The due date printed on the bill is verified from the customer preferred due date, the billing cycle due date, the control file, or the due date entered on the bill print screen. System will select the appropriate due date without manual intervention.			
2.10.1.11	Provide customers with options on the layout of their bill, for example offer a detailed bill or a summarized bill with limited information.			
2.10.1.12	Transaction code and description of the charge.			
2.10.1.13	Current charges.			
2.10.1.14	Past due balance.			
2.10.1.15	Multiple payments received listed separately.			
2.10.1.16	Adjustments code and description of the item adjusted.			
2.10.1.17	Service charges.			
2.10.1.18	Graph showing consumption/usage for current and prior 12 months for each service.			
2.10.1.19	Ability to add shading and textures.			
2.10.1.20	Ability to generate an on screen preview of created bills.			
2.10.1.21	Ability to add headers and footers, dynamic not static.			
2.10.1.22	Provides for a check digit to be included on the bill.			
2.10.1.23	Provide 12 month average usage on the bill.			
2.10.1.24	Statement regarding the billing periods weather and possible effects on usage.			

2.10.1.25	Statement of number of days in billing period and average daily usage by service.			
2.10.1.26	Separate line items for charges by service, product and program offering.			
2.10.1.27	List the rate code and description for each service and line item.			
2.10.1.28	Rate components (base charge, fuel charge, tax rate, etc.).			
2.10.1.29	Separate line item for deferred payment arrangements.			
2.10.1.30	The difference between accumulated charges and the average or levelized payment plan amount.			
2.10.1.31	For power customers provide actual, adjusted and billed demand read in kW and KVA, KQ, KVAR.			
2.10.1.32	Total usage per service in appropriate energy unit; kWh, kW, power factor, etc. (Interval customers - time and date of peak demand)			
2.10.1.33	For water customers provide actual, adjusted and billed demand read in cubic feet and cubic meters (plus all other applicable read types)			
2.10.2 Bill Messages				
2.10.2.1	Global custom messages. All bills produced will have a single message.			
2.10.2.2	Custom messages on the bill through user-defined criteria.			
2.10.2.3	Custom messages by individual customer.			
2.10.2.4	Custom messages by service.			
2.10.2.5	Sign-up for Autopayment program using the bill with a signature blank.			
2.10.2.6	Indicate the charges billed at a reduced rate for all applicable services. (e.g. Senior Citizen Discount)			

2.10.2.7	Advertise potential average and levelized payment plan accounts via a line item on the customer bill listing the payment and start date (customers may sign up for the levelized payment program at any time).			
2.10.3	Special Handling and Bill Delivery			
2.10.3.1	Assignment of special handling codes to the bill for purposes of sorting, bill printing, reviewing, routing, and mailing. The system will accommodate grouping customer's bills together for placing in the mailing envelope together.			
2.10.4	Mailing Address Certification			
2.10.4.1	Provide bar coding of postal information			
2.10.4.2	Provide CASS certification of the mailing address for postal discount.			
2.10.5	Bill Printing			
2.10.5.1	System will provide multiple capabilities for sorting bills. (e.g. Zip code, cycle, customer number)			
2.10.5.2	System provides sorted output in accordance with Canadian Postal Service standards. For example: sort bills based on Canadian postal codes.			
2.10.5.3	Input a range of bills to be produced. For example, the entire bill run does not need to be printed all at one time.			
2.10.5.4	Produce a single bill for all charges.			
2.10.5.5	System will display the number of bills to be printed. (By bill type)			
2.10.5.6	System will display the number of bills remaining to be printed. (By bill type)			
2.10.5.7	System will display the number of total bills printed.			
2.10.5.8	System allows restarting of a bill run from any point within the bill run. (By bill type)			

2.10.5.9	System allows a bill run to be paused and restarted.			
2.10.5.10	System is capable of creating a text only version of any bill for email attachment purposes.			
2.10.5.11	Produce separate bills for a specific service, product, or program.			
2.10.5.12	Accommodate different formats for different types of bills. For example, the disconnect bill is in a different format than the regular bill.			
2.10.5.13	Provide customers with options on the layout of their bill, for example offer a detailed bill or a summarized bill with limited information. (Large Print, Braille, Foreign language support)			
2.10.5.14	Re-print a duplicate copy of the current bill in an on-line mode.			
2.10.5.15	Re-print a duplicate copy of the bill for any previous billing period.			
2.10.5.16	Re-print the current bill after adjustments have been made.			
2.10.5.17	Provide the ability to send a duplicate copy or portion of the bill to any third party defined for the account.			
2.10.5.18	Provide the customer with the number of bill copies requested.			
2.10.5.19	Generate customer bills to a digital media such as tape or disk. (Sending)			
2.10.5.20	Generate customer bills to a digital media such as tape or disk. (Saving)			
2.10.5.21	Provide user defined pull bill identifiers to separate and deliver requested bills to requestor			
2.10.5.22	Explain the complexity of changing a bill print design to meet ongoing changes as set by the OEB or Ministry of Energy.			
2.11	Billing Controls & Reporting			
2.11.1	Billing Controls			

2.11.1.1	Billing cross-checks are available to ensure that all reads were input, all charges calculated correctly, and all bills printed for the scheduled cycles and off-cycle account.			
2.11.1.2	Validation of the bill consumption and dollar amount against a user defined range; provide on-line review of the bills which fail this test with automatic disposition of print and send-out or adjust and recalculate.			
2.11.1.3	The system supports aggregate and customer classification (for example, usage category) audits to ensure that all consumption is billed correctly.			
2.11.1.4	Capability of producing preliminary billing register listing all accounts to be billed including line item detail and total amount billed.			
2.11.1.5	Provides adequate control, balancing and reconciliation between the billing cycle revenues and the general ledger revenue cycles.			
2.11.1.6	Provide report of aged bills not printed			

End of Section

Table 10.2.4. Credit and Collection Management

3.0 CREDIT & COLLECTION MANAGEMENT				
Item	Function / Feature	Vendor Score	Comments	Work Effort
3.1	Customer Credit			
3.1.1	Credit Profile			
3.1.1.1	Capture basic customer credit information in order to provide a credit profile, credit score and credit status of the customer.			
3.1.1.2	Systems captures customer information such as disconnects, NSF or any other customer credit situation			
3.1.1.3	Credit information fields are user-defined and unlimited.			
3.1.2	Credit Checking			
3.1.2.1	Download credit (Equifax, Dun & Bradstreet, etc.) information directly into the system for on-line accessibility			
3.1.2.2	Identify customers who have been pre-approved for credit. For example, large customers might be eligible for waiver of deposit, residential customers approved for appliance purchases. (Property owner with several properties.)			
3.1.2.3	For employees of Ottawa Hydro do not conduct credit checking activities.			
3.1.2.4	Share customer credit ratings or scores with marketers.			
3.1.3	Credit References			
3.1.3.1	Provide a letter of reference to a former customer in order to establish credit with a new utility company. The letter will include specific information about the customer's history such as the number of late payments.			

3.1.3.2	Summarize and print the customer's credit history for the past 12 months on the closing bill for use as a credit reference with another utility based upon specified criteria.		
3.1.4	Credit Bureau Interface		
3.1.4.1	Automated interface with various credit bureaus. System will provide a mechanism for transferring and receiving various information pertaining to customers. (HO will pick)		
3.1.4.2	Process payments received by credit bureaus.		
3.1.5	Credit Scoring Process		
3.1.5.1	A flexible credit scoring capability, the user can vary weights associated with various credit offences. Collection points for credit scoring purposes are applicable to all types of accounts.		
3.1.5.2	The credit score takes into consideration the number of years connected and the past credit events, applying a weighted value to the customer's most recent history.		
3.1.5.3	System will provide the ability to manually adjust or override a customer's credit score. (Security will be configurable)		
3.1.5.4	Transfer the credit score from the old account to the new account.		
3.1.5.5	Determine credit worthiness and assess deposits. (see financial management for deposit processing)		
3.1.6	Cash Only Account		
3.1.6.1	Automatic identification of a "cash only" account based on a specific credit rating or a user defined criteria.		
3.2	Account Balance		
3.2.1	Outstanding Account Balance		

3.2.1.1	Provide capability to isolate a balance owing on any given date in the account history. Isolated balance will prohibit delinquency or disconnect.		
3.2.1.2	Provide an on-line summary or report of all amounts owed by an entity having multiple service locations, active, closed and pending.		
3.2.2	Transfer Account Balance		
3.2.2.1	New service requests will be cross referenced against inactive accounts with outstanding balances or accounts disconnected for non-payment with outstanding balances transferred to the new account.		
3.2.2.2	Ability to transfer delinquent balances between a customer's accounts.		
3.2.2.3	Allow adjustments to accounts which have balances due because the service was terminated after the requested date.		
3.2.2.4	Allow for transfer of charges from customer whose account was terminated after the requested date to the customer (including apartment complexes) who actually used the service.		
3.2.2.5	The ability to transfer a deposit.		
3.2.3	Freezing an Account		
3.2.3.1	Allow for accounts to be "frozen" so that no action is taken during any delinquent review process.		
3.3	Collections		
3.3.1	Notification and Cut-off for Non-Payment		
3.3.1.1	Support an automated notice and collection activity for all customers based upon specific processing date schedules by customer class.		
3.3.1.2	Ability to define an automated notice and collection process by service, product, and program.		

3.3.1.3	Exclude specific utility service and product charges from the delinquent notice process.		
3.3.1.4	Exclude specific customers from the delinquent notice process based upon contract terms.		
3.3.1.5	Provide the ability to generate past-due notices with a varying degree of severity based upon customer credit history. System allows notices to be tailored to customers with better or worse credit history.		
3.3.1.6	Provide the ability to generate notices for delinquent payment arrangements; System will automatically generate the notice the next day after the payment is not received.		
3.3.1.7	Provide the ability to grant payment extensions which will extend the delinquency process accordingly. Customer provides a specific date or length of the extension.		
3.3.1.8	System will track the number of payment extensions granted for a customer. Payment extensions will affect a customer's credit history.		
3.3.1.9	A sequence of delinquent and non-pay disconnect notices can be identified. The system will support any number of notices with variable contents and format.		
3.3.1.10	Cut-off processing will include automatic generation of cut service orders.		
3.3.1.11	Ability to select the number of orders to be worked each day by geographic area.		
3.3.1.12	Cut off orders will automatically be removed if payment is received		
3.3.1.13	Ability to designate work groups for working of orders		
3.3.1.14	Track and report number of orders not worked over "x" days.		

	Allow for preventing turn-off of service (by service) due to delinquency for various reasons including:		
3.3.1.15	> Payment Arrangements (automatic)		
3.3.1.16	> Bankruptcy Proceedings - Pre-petition account		
3.3.1.17	> Pledges / Contributions		
3.3.1.18	> Life Support (automatic)		
3.3.1.19	> High Bill Investigation/Bill Disputes		
3.3.1.20	> Re-Read Order Pending		
3.3.1.21	> Payment Extensions		
3.3.1.22	> Payment Arrangements (automatic)		
3.3.1.23	> Other User Defined Circumstances. (i.e. bill 210)		
3.3.1.24	Allows for circumvention of the final disconnect notices and non-pay disconnect orders during periods of severe weather.		
3.3.1.25	Identification and reporting of non-pay disconnect customers for subsequent follow-up.		
3.3.1.26	Preparation of a non-residential delinquency notice is based primarily on a total unpaid dollar amount or an aging threshold determined by the credit and collection staff. (Plus the deposit held)		
3.3.1.27	Notices will be mailed directly to customers except for those identified as special handling.		
3.3.1.28	Suppress or issue disconnect notices either individually, in groups, or by area.		
3.3.1.29	Provide for the printing of disconnect orders by route or meter sequence.		
3.3.1.30	Allow for the printing of a variable expiration date at the time the disconnect notice is created. For example specify a 7 day allowance for payment instead of 15 days.		
	Disconnect notices must include the following:		

3.3.1.31	> The mailing address, delivery point, and/or the customers service address.		
3.3.1.32	> Account number		
3.3.1.33	> State the reason for the proposed termination (optional language. Polish, Spanish, Russian)		
3.3.1.34	> Total outstanding balance and past due amount.		
3.3.1.35	> Date Due and time to pay by		
3.3.1.36	>Telephone Number		
3.3.1.37	> Notice of additional Deposit amount		
3.3.1.38	> Notice of a reconnect fee		
3.3.1.39	Provide the ability to view or print all charges by account which are past due "x" days from their creation by service.		
3.3.1.40	On-line identification or reporting of accounts that have been turned off for non-pay.		
3.3.1.41	Viewing of accounts which are scheduled for write-off.		
3.3.1.42	Provide for moving accounts to bad debt status once user defined criteria for inability to collect from customer has been reached, maintaining on-line access to inactive accounts.		
3.3.1.43	On-line identification or reporting of accounts that have been turned off for non-pay.		
3.3.1.44	Provides an automatic flag on an account that has been disconnected for 6 months or more.		
3.3.1.45	Add these accounts to the collection process after X number of days		
3.3.1.46	Identify by date parameter if service order is required to double check for self-reconnect		
3.3.1.47	Provide field to enter confirmation of disconnect state checked and intact		
3.3.1.48	Accommodate load limiting devices		
3.3.1.49	Send notices based on prior credit history		
3.3.1.50	Auto charging of deposits		

3.3.1.51	Ability to calculate required deposit and increase and decrease deposits on hand as required by regulation, en masse.		
3.3.1.52	Automatic refund of deposit when a customer moves from SSS billing to retailer consolidated billing.		
3.3.1.53	Able to recommend the correct deposit to charge the customer on-line during new account set up.		
3.3.1.54	Able to track deposits waived by the users		
3.3.1.55	create t-5's		
3.3.1.56	Automatic generation of field orders		
3.3.1.57	Deposit calculator based on different criteria		
3.3.2	Collection Agency Interface		
3.3.2.1	Automated interface with various collection agencies to report customers in a collection status. (Reports all accounts)		
3.3.2.2	Receive payment information regarding customer collections.		
3.3.3	Public Assistance Agency		
3.3.3.1	Automated interface with public assistance agencies for payments made to a customer's account by the agency.		
3.3.3.2	On-line access to a list of customers receiving agency assistance and the amount they qualify for.		
3.3.3.3	On-line access to lists of assistance and other agencies and telephone numbers.		
3.3.4	Employee Collections		
3.3.4.1	View company employee payment and collection status.		
3.4	Penalty		
3.4.1	Late Payment Penalty		
3.4.1.1	Allow for a late payment penalty on all types of accounts. (Compounded interested)		

3.4.1.2	Late payment penalty applied based on a flat dollar amount or a percentage of the balance due.		
3.4.1.3	Upon receipt of a partial late payment, system will automatically indicate the payment amount on the delinquency notice and reduce the balance due.		
3.4.1.4	Provide ability to allow selected accounts to be late payment penalty exempt		
3.5	Returned Checks		
3.5.1	Debit returned checks back to the customer's account and create appropriate returned check charge. (Must be configurable)		
3.5.2	Customers with returned checks will automatically be placed into the delinquency process if the charge is past due.		
3.5.3	Appropriate associated G/L accounts will be adjusted accordingly without any manual intervention.		
3.5.4	Call, mail or deliver to the customer, notice of the returned check based on the credit history. Severity of the notice will reflect the recent credit score for the customer. Ability to overlook an NSF for good credit history.		
3.5.5	System will automatically apply a returned check fee upon entry of the reversal of the payment.		
3.5.6	Waive the returned check fee pending approval. System will provide the ability to override the fee without an adjustment to the account.		
3.5.7	Stop payments to be treated individually		
3.5.8	Reversal of returned check fee will automatically reverse delinquent points originally associated with returned check fee		
3.6	Payment Arrangements		

3.6.1	Track the number of payment arrangements granted to an account in a running twelve month period.		
3.6.2	Track the number of payment arrangements not met. For each arrangement that is made provide the ability to track default.		
3.6.3	Establish and maintain customer payment arrangements based upon an instalment arrangement. Total balance owing can be divided into multiple user-defined instalments.		
3.6.4	Establish payment arrangements on the final bill of an inactive account. Providing customers the ability to pay total balance with an arrangement agreement after they have moved from the Utility service area.		
3.6.5	Track payment arrangements on both active and inactive accounts and render notices based on the terms of the payment arrangement in lieu of the criteria established for regular notices. The notices may have additional terminology reflecting default.		
3.6.6	System is capable of generating on-line the initial payment schedules and amounts.		
3.6.7	System is capable of printing the arrangement agreement as it is established with the customer.		
3.6.8	System will allow the user to adjust the arrangement amount for each payment.		
3.6.9	System will allow the user to adjust the arrangement due date for each payment		
3.6.10	Payment arrangement does not need to be tied back to a specific debit in the account and can be made for any amount.		
3.6.11	Payment arrangement dates will be user defined.		

3.6.12	Automatically generate instalment payment letters. System will provide the ability to send "reminder" notices to customers with payment instalments.		
3.6.13	Payment arrangements preclude account from entering write-off processing. Arrangements are made to assist a customer in preventing delinquency or disconnect notices.		
3.6.14	On-line view or report of payment arrangements made with a customer for an account. Report can be segmented by class, status of arrangement, or amount.		
3.7 Active Account Collections			
	The system will facilitate the identification of active accounts in delinquency. The system will support the following activities:		
3.7.1	> Identification of previous credit and collection actions taken on the account		
3.7.2	> Outbound mailing to notify or warn the customer of pending collection activity		
3.7.3	> Feed the collection action into an electronic work queue to be followed up by other users		
3.7.4	> Initiate collection order sequence		
3.7.5	> Request additional deposits		
3.7.6	> Special 72 hour notices will be accommodated		
3.8 Inactive Account Collections			
3.8.1	The system will facilitate the identification of inactive accounts with outstanding balances and bad debts.		
	The system will support the following activities:		
3.8.2	> Identification of previous credit and collection actions taken on the account		
3.8.3	> Transfer balance owing to the new customer account		
3.8.4	> Resend returned collection letters		

3.8.5	> Refer the account to a collection agency.			
3.8.6	> Notify account third parties			
3.8.7	> Record bankruptcy or Receivership. (Track claims)			
3.8.8	Bad Debts			
3.8.8.1	Provide for automatic write-off of accounts based upon user defined parameter by service. Allow for override of this automated process (secured by user).			
3.8.8.2	Provide for manual write-off capability. User has the option to select specific charges that are past due and perform write-off. This would include active accounts.			
3.8.8.3	Provide a mechanism for easily tracking and identifying inactive accounts with outstanding balances due.			
3.8.8.4	Recall accounts assigned to a collection agency. Once an account has been turned over to an agency, the Utility can manually override an individual account or a mass of accounts.			
3.8.8.5	Allow for the input and on-line review of account collection status, for example: Negotiated, Settled, Forgiven, Reversed, and Bankruptcy.			
	Provide an on-line view or report of the write-off processing affected accounts, include review of the write-off customer information such as:			
3.8.8.6	> Account Notes			
3.8.8.7	> Credit Bureau Indicator			
3.8.8.8	> Date Sent to Credit Bureau			
3.8.8.9	> Collection Service Indicator			
3.8.8.10	> Date Sent to Collection Service			
3.8.8.11	> Collection Service Reference Number			
3.8.8.12	> Customer Connect Date			
3.8.8.13	> Customer Close Date			

3.8.8.14	> Customer Credit History			
3.8.8.15	> Write-off Balance Owing			
3.8.8.16	On-line view or report of customers who have made payments and are currently being collected through an outside agency.			
3.8.8.17	On-line view of payments collected by receivable type for a specified period of time. For example: all electric payments, all tax payments, etc...			
3.8.8.18	On-line view or report of accounts with balances past-due for a predetermined number of days. The report would indicate accounts which are ready to be written-off.			
3.8.8.19	On-line view or report of contacts/notices made to accounts in the collection process. System will provide a mechanism to input collection contacts into the CIS.			
3.8.8.20	Daily open account balance report by receivable type. Examples include: Electric service fees, Taxes, etc...			
3.8.8.21	Capability to produce upon request a delinquency listing of all accounts with unpaid amounts greater than x days old since date the bill was mailed. This listing of delinquencies can be produced under various parameters such as customer class.			
3.8.8.22	Automatically generate multiple notification collection letters on final billed accounts with user-defined minimum balances after "x" number of days after inactivation.			
3.8.8.23	Provide the ability to create forms required for lawsuits and related documents.			
3.8.8.24	Automatically review all accounts referred to collections process at designated intervals to create subsequent letters on accounts for which no payment has been received.			

3.8.8.25	System will maintain with the customer history the type of letter or legal transaction along with the date of production on the account.			
	Process a bad debt report at specified intervals to indicate the following items:			
3.8.8.27	> The starting balance and number of accounts (total receivables)			
3.8.8.28	> The addition of accounts referred (dollar and number)			
3.8.8.29	> Additions and reductions due to adjustments			
3.8.8.30	> The number of payments received and the dollar total of those payments			
3.8.8.31	> The totals for the end of the report period (total receivables)			
3.8.8.32	Provide the capability to request a listing of each type of account (current legal status) to indicate both total numbers and total dollar value.			
3.8.8.33	System provides a means for automatically archiving and purging bad debt history information.			
3.8.8.34	Provide for the transfer of records from the accounts receivable when collection activity has been completed. Appropriate G/L interface transactions will occur.			
3.8.8.35	Provides the ability to write-off unclaimed credits			
3.8.8.36	Ability to write off partial a/c - electric portion - water lien against property - tax transfer			
3.9	Bankruptcy			
3.9.1	Identify and maintain bankruptcy information on the customer account. Upon notification that a customer has filed for bankruptcy the account is closed as of the date of filing.			

3.9.2	The delinquency process for a bankruptcy customer is stopped for the amount due at the time of filing to prevent the service from being disconnected for non-payment or going to a collection agency for the closed account.			
3.9.3	On-line review or report of the amount owed by customers (Customer class) who have filed for bankruptcy.			
3.9.4	Tracking of dismissals and discharges.			
3.9.5	Indicate on the new account that the customer has filed for bankruptcy on an old account.			
3.9.6	Ability to generate a "x" day deposit letter for post bankrupt account(s). Requesting for an additional deposit on the new account.			
3.10	Deceased/Executor			
3.1.1	Identify a customer as deceased and assign an executor to the account.			
3.11	Vacant Account Usage (see also Usage Mgmt)			
3.11.1	Provide for the identification of usage on a vacant account			
3.11.2	Support the revert to landlord /owner process for the account.			
3.11.3	Add vacant account usage to the collection process after "X" number of days.			
3.11.4	Flag the responsible party of the account when unauthorized usage of service is detected.			
3.11.5	Generate a service order to confirm current tenant/owner when X kWhs are metered on an inactive account (X being a variable parameter)			

End of Section

Table 10.2.5. Customer Management

4.0 CUSTOMER MANAGEMENT				
Item	Function / Feature	Vendor Score	Comments	Work Effort
4.1	Customer Entity			
4.1.1	Customer Identification and Access			
	Provide the ability to access the customer by the following key fields:			
4.1.1.1	> Customer Name with Partial Search Capability			
4.1.1.2	> Social Insurance number (SIN) (required field) (Two fields)			
4.1.1.3	> Federal Business Identification Number			
4.1.1.4	> Drivers License Number / Work ID Card / Credit Card			
4.1.1.5	> Spouse or Significant Other Name (Authorized User) -2 fields			
4.1.1.6	> Doing Business As Name (D.B.A.)// Business Name			
4.1.1.7	> Phone Number (Cell Phone) Need more than one number with ext.			
4.1.1.8	> Nickname			
4.1.1.9	> Customer Identification Number			
4.1.1.10	Provide for a combination of search criteria e.g. SIN number and name.			
4.1.2	Customer Status or Situation			
4.1.2.1	At the time a conversation is initiated the system will highlight negative history, open contact items, cash only status of the customer.			
4.1.2.2	The system will readily distinguish between current customers receiving services and potential customers.			
4.1.2.3	Distinguish between current services which the customer is taking advantage of and the potential for the expanded products, services, and programs that are available.			
4.2	Customer Set-up and Link			

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4.2.1	System will provide the ability to generate an application form, assisting the user in the process of entering and validating applicant information.			
4.2.2	The customer is established in the system and immediately linked to a single account number.			
4.2.3	The customer is established in the system and immediately linked to multiple accounts, multiple services, and/or multiple premises.			
4.2.4	System allows the user to suspend or store an incomplete application in a temporary work area for later reactivation and completion. (suggest 60 days to hold a incomplete application)			
4.2.5	The customer can establish various addresses including; service addresses, mailing addresses, temporary addresses, etc.			
4.2.6	Provide the ability to standardize commonly used customer names so that they will always be spelled the same--for example, grocery chains, etc.			
4.3	Customer Based Information			
	Information specific to the customer is maintained or is associated with a customer from one service address or account to another. This information includes:			
4.3.1.1	> Billing History			
4.3.1.2	> Payment History			
4.3.1.3	> Consumption History			
4.3.1.4	> Product History			
4.3.1.5	> Credit Profile History			
4.3.1.6	> Alias Names, Driver's License			
4.3.1.7	> Special Conditions			
4.3.1.8	> Spouse or Significant other Names, Roommates, DL#			
4.3.1.9	> Mailing Address			

4.3.1.10	> Deposit Information			
4.3.1.11	> Theft and Tampering History (Diversions)			
4.3.1.12	> Customer Complaints			
4.3.1.13	> Customer Correspondence (inbound and outbound)			
4.3.1.14	> History of Service Addresses both Present and Past			
4.3.1.15	> Contracts in Effect			
4.3.1.16	> Banking Information (for automatic drafting purposes)			
4.3.1.17	> Date of Birth			
4.3.1.18	> Doing Business As Name (D.B.A.)			
4.3.1.19	> Phone Number(s) (Cell phone, Unlisted phone, etc.)			
4.3.1.20	> Email Address(es)			
4.3.1.21	> Fax Number (s)			
4.3.1.22	> Customers Primary Language (English/French)			
4.3.1.23	> Identify Dangerous Animals/People/Situation			
4.3.1.24	> Confidentiality requested			
4.3.1.25	> Primary SIC			
4.3.1.26	> Headquarters and Branch Locations			
4.3.1.27	> Employer			
4.3.1.28	> Emergency Contact (Name & Method of Contact)			
4.3.1.29	System provides the user the flexibility to display account summaries of a customer on a single screen and drill-down capability.			

4.3.1.30	Information data fields are tailored and will only display based on the customer type. For example: Commercial customers will have fields for Departmental contacts - residential will not.			
4.3.1.31	Supports user defined fields for the customer entity.			
4.3.1.32	Maintain customer demographics such as family size.			
4.3.1.33	Vital Services By-Law			
4.3.1.34	Critical Health Issues			
4.3.2	Customer Correspondence			
4.3.2.1	System is capable of maintaining an on-line history of all inbound and outbound correspondence.			
4.3.2.2	Document specific customer correspondence received i.e... date, specific comments, including date/time they called etc.			
4.3.2.3	Provide for the capture of customer correspondence through an imaging system. Image can then be retrieved at any point during future customer conversation.			
4.3.2.4	Potential Customers			
4.3.2.5	Establish and track entities who are not current utility customers but are potential customers.			
4.3.2.6	Establish and track entities who are not current customers but have a one time billing or service event. Merchandise sales, property damage, etc.			
4.3.2.7	Establish and track entities with a direct relationship to a customer. For example 3rd party, owner, property management company, landlord, family.			

4.3.2.8	Potential customers are location independent. A service address in the land database is not required.			
4.3.4	Credit Profile			
4.3.4.1	Credit profile information is provided including user defined fields.			
4.3.4.2	View a customers credit profile for a customer across all accounts. System has the ability to combine multiple accounts together to provide a "credit at a glance" function.			
4.3.5	Special Conditions and Special Assistance			
4.3.5.1	System supports the establishment and maintenance of customers that have specific conditions.			
4.3.5.2	Special conditions may include: medical conditions, life support, elderly, disabled, customer situation etc.			
4.3.5.3	Users can define a re-certification date for a special condition.			
4.3.5.4	System automatically generates notification of pending removal of a special condition status in a user specified number of days from the re-certification date.			
4.3.5.5	Provide for tax and penalty exemptions at the customer level.			
4.3.5.6	Provide for Debt Retirement Charge (DRC) exemption at the customer and/or service level.			
4.3.5.7	Provide for additional access and update security to add/delete/change GST, DRC and/or penalty exempt.			
4.3.5.8	Provide for report function and or on-line query of customers and/or services which have been assigned a GST, DRC or late payment penalty exemption.			

End of Section

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Table 10.2.6. Customer Service Care

5.0 CUSTOMER SERVICE - CARE				
Item	Function / Feature	Vendor Score	Comments	Work Effort
5.1	Customer Contact Types			
	Accommodate interaction with the customer through the following methods:			
5.1.1	> Inbound telephone calls direct to agent via switch			
5.1.2	> Inbound telephone calls through IVR			
5.1.3	> Inbound telephone calls through CTI			
5.1.4	> Outbound telephone calls direct to customer. (Manual/Preview predictive)			
5.1.5	> Inbound website account access			
5.1.6	> Inbound website electronic commerce (E-Commerce)			
5.1.7	> Inbound email			
5.1.8	> Outbound website / E-Commerce / Email			
5.1.9	> Inbound faxes			
5.1.10	> Outbound faxes			
5.1.11	> Inbound correspondence			
5.1.12	> Outbound correspondence			
5.1.13	> Outbound bills			
5.1.14	> Inbound payments and bill stubs			
5.1.15	Provides the ability to faxes			
5.1.16	Provides the ability for escalation tracking of OEB reports			
5.1.17	Provides the ability for tracking all changes made on a account			
5.2	Customer Calls			
5.2.1	Inbound Calls			
	Accommodate the following inbound call types:			
5.2.1.1	> Trouble Calls - integration to the OMS (GIS, & transformer number)			
5.2.1.2	> Open / Close Accounts			
5.2.1.3	> Update Account Information (move in/out)			

5.2.1.4	> General Inquiry			
5.2.1.5	> Billing Inquiry			
5.2.1.6	> Credit Inquiry (Deposits)			
5.2.1.7	> Energy Service (Conservation Information)			
5.2.1.8	> Customer Projects (Customer Projects & Installations)			
5.2.2	Outbound Calls			
	Accommodate the following outbound call types:			
5.2.2.1	> Marketing campaign calls			
5.2.2.2	> Credit / Collection calls (Call Queues) (Preview or Predictive)			
5.2.2.3	> Trouble Update calls (Call Queues) (Preview or Predictive)			
5.3	Customer Self Service			
5.3.1	Customer Self Service - Interactive Voice Response			
5.3.1.1	Provide account inquiry capabilities via interactive voice response.			
5.3.1.2	Provide account update or action capabilities via interactive voice response, for example: request service, request a connection/disconnection, and make a payment.			
5.3.1.3	Capture incoming telephone number from IVR unit and update CIS for accounts with no phone number.			
5.3.1.4	Provides authentication and self service of pin code change.			
5.3.1.5	Move the customer back into IVR with conference capability to assist with IVR navigation.			
5.3.1.6	Option to route repeat customer call to agent that answered the initial call			
5.3.2	Customer Self Service - Internet Integration			
5.3.2.1	Provide for a security access number e.g. customer PIN			
5.3.2.2	Provide for account review			

5.3.2.3	Provide for service connection/transfer/disconnection			
5.3.2.4	Provide for inquiry into pending order and service order status.			
5.3.2.5	Provide for review of the bill, both current and historical			
5.3.2.6	Provide for payment of the bill			
5.3.2.7	Provide for review of rates, pricing plans, financing options.			
5.3.2.8	Provide for review and procurement of products and merchandise			
	Provide for entry of customer read meter read			
5.3.2.9	Flexibility to enable any conversation or information for customer access and self service.			
5.3.3	Customer Self Service - Electronic Commerce			
5.3.3.1	Provide for electronic bill presentation.			
5.3.3.2	Provide for electronic payment.			
5.3.4	Customer Self Service - Fax on Demand			
5.3.4.1	Provide for faxing of customer requested information. (Authentication should be there)			
5.3.4.2	Allow CSR's to fax information to customer from the desktop			
5.3.4.3	Allow customers to fax information to CSR.			
5.4	Customer Contact & Scripting			
5.4.1	Customer Contact Management			
5.4.1.1	Allows for up front identification of the customer or potential customer with the use of Caller ID and Computer Telephone Integration. Personalize the conversation by extracting information from the data base and displaying it for use by user personnel.			

5.4.1.2	The system provides for the recording of the customer contact including the type of contact, who responded to the contact, the date/time the contact started, and the contact outcome.			
5.4.1.3	Ability to search and view potential and existing customer contacts by any defined field. e.g. date (most recent contact displayed first), service, location, etc.			
5.4.1.4	Automatic identification of skill set responsible for the account.			
5.4.1.5	The customer contact feature is fully integrated with the customer scripting process. Standard utility operating procedures can be displayed for call types.			
5.4.1.6	Display of contact start and completion times to view length of time spent on customer contact.			
5.4.1.7	The customer contact feature is fully integrated with the systems automated work queue process. Specific contact call types will be automatically routed to work queue.			
5.4.1.8	Contact and performance statistics are provided. (Number of calls, satisfied or completed calls, length of time for completion.)			
5.4.1.9	Provides the ability to link documents to an account. (Voice clips, fax, scanned documents)			
5.4.1.10	Provide the ability to capture activities completed on customer accounts (contact log, notes, etc). Log types should be available from a pick list to speed data entry plus freeform text fields.			
5.4.1.11	Personal password access--allow a customer to provide the CSR with a password verifying who they are. Similar to banks and credit card firms			

5.4.1.12	Alerts--display critical alerts based on the customer profile.			
5.4.2	Customer Conversation Scripting			
5.4.2.1	The customer conversation will be standardized and structured through the use of an intelligent scripting facility or similar mechanism. Contact script will be tailored based on the type of call.			
5.4.2.2	The development of scripts is flexible and can be customized to a defined group of users such as all CSR's or an individual.			
5.4.2.3	A script can easily be selected from a list of scripts based upon the contact type or role of user.			
5.4.2.4	The script will provide for a logical flow of conversation and related windows, however, the user may deviate from the script.			
5.4.2.5	The script can be easily viewed and is fully accessible during the customer conversation.			
5.4.2.6	In addition to the flow of conversation a script will include information which can be used to inform the customer, respond to customer questions, or solicit customer responses.			
5.4.2.7	An end-user following the scripting process will automatically create an entry in the customer contact log.			
5.4.2.8	Provide for a function to record the customer contact from individual screens being used outside of the scripting and contact process, via a fastpath key, or function key.			
5.4.2.9	Provide scripting and performance statistics.			
5.5	Customer Marketing & Sales			
5.5.1	Marketing			
5.5.1.1	Provide for lead identification and tracking.			

5.5.1.2	Provide for the creation and management of marketing campaigns.			
5.5.1.3	Provide for the identification of market segments and segment analysis.			
5.5.1.4	Develop a customer profile for specific products and services in order to target customers for marketing campaigns.			
5.5.1.5	Identify customers for focus groups based on measures such as consumption, revenue, location, SIC, etc.			
5.5.1.6	Provide for list creation and management			
5.5.1.7	Provide for electronic marketing capabilities			
5.5.1.8	Provide for customer profiling			
5.5.1.9	Provide for relationship marketing			
5.5.1.10	Provide for business to business marketing			
5.5.1.11	Provide ROI analysis for new products and services			
5.5.1.12	Provide for product research and development services			
5.5.2	Existing Customer Marketing			
5.5.2.1	Provide on-line prompting regarding new products, programs and services available.			
5.5.2.2	Integration and utilization with the scripting process to include marketing activities. This would include selling tips, or features of the products, services, or programs.			
5.5.2.3	Provide for the on-line identification and segmentation of the existing customer base through any data entity or data relationship (used to target market customers for any process).			

5.5.2.4	Provide for the download of customer records into Client (Excel, Lotus, and Access) software for subsequent manipulation.			
5.5.2.5	Targeted customer's can be sent a detailed marketing message on their bill indicating new products or services available.			
5.5.3	Potential Customer Marketing			
5.5.3.1	Prompt the potential customer regarding products, programs and services available at the requested service address.			
5.5.3.2	Provide for the recording of potential customers regardless of location for purposes of target marketing.			
5.5.3.3	Provide for customer correspondence based on specific customer request or need. (Promotional materials or literature for new product or services).			
5.5.3.4	System will provide a mechanism for initiating and tracking the success of a marketing campaign and the campaign results through additional sales made.			
5.5.4	Sales			
5.5.4.1	Provide sales force automation capabilities			
5.5.4.2	Provide for opportunity management			
5.5.4.3	Provide for remote access			
5.5.4.4	Provide for forecasting and quoting			
5.5.4.5	Provide presentation capabilities			
5.5.4.6	Provide contact management			
5.5.4.7	Provide prospect management			
5.5.4.8	Provide account management			
5.5.5	Marketing/Sales Interface			
5.5.5.1	Provide for electronic notification to the marketing system of a customers interest in a new product, service, or program, requiring follow-up.			

5.5.5.2	Provide for the electronic notification from the marketing system of the assigned customer account executive. After an account has been established, CIS will be provided the necessary information.			
5.5.5.3	Utilization of the customer systems customer base as the primary data base, with automated synchronization between the customer system and the marketing system. Information can be updated from either system.			
5.5.5.4	Extract customer data from CIS and provide to the marketing system			
5.5.5.5	Extract customer data from CIS and provide to a marketing data warehouse			
5.6	Commodity Planning			
5.6.1	Provide commodity consumption, revenue and demand information and adjustments to external systems to assist in forecasting on a monthly and as required basis. (for Major Accts)			
5.6.2	For key transmission and distribution customers provide customer profile information such as number of sites, locations, sales, etc. on an as required basis. (for Major Accts)			
5.6.3	Integration to a load management system.			
5.7	Satisfaction and Success			
5.7.1	User Performance Measurement			
5.7.1.1	Provide for the input of benchmarks for specific events for example: length of time certain events should take to complete.			
5.7.1.2	Provide for usage and performance based analysis and reporting.			
5.7.2	Customer Satisfaction Measurement			

5.7.2.1	Provide for the generation of standardized form letters and responses to customer inquiries with information from the customer account as required. For example: Product inquiries, thank you letters, etc.			
5.7.2.2	> Customer feedback regarding new customer connection.			
5.7.2.3	Provide for automated follow-up with customers through telephone calls or correspondence triggered through the work queue or similar mechanism. For example: at the completion of certain call types, correspondence will automatically be generated.			
5.7.3	Program Success Evaluation			
5.7.3.1	Provide consumption information for customers who have participated in a Home Improvement Program to validate energy savings.			
5.7.3.2	Associate customers with a product, program or service resulting from a marketing campaign.			
5.7.3.3	Provide customer revenue information for specific products, programs or services to be used in the analysis of profitability.			
5.7.3.4	Provide for the extract of customer records.			
5.8	Correspondence			
5.8.1	Ability to create correspondence templates including forms.			
5.8.2	Provide for the generation of standardized form letters and responses to customer inquiries with information from the customer account as required. For example: confirm meter reading, rebill account, estimated reading, change meter.			
	Automatically send correspondence when:			
5.8.3	> returned check			

5.8.4	> Pre-authorized payment / Credit Card			
5.8.5	> As required or as necessary			

End of Section

Table 10.2.7. Financial Management

6.0 FINANCIAL MANAGEMENT				
Item	Function / Feature	Vendor Score	Comments	Work Effort
6.1	Deposits			
6.1.1	Deposit Assessment			
6.1.1.1	Provides the ability to assess deposit by service. Separate deposits can be collected and reported for Electric, etc.			
	System allows the method for determining default deposit requirements to vary for each type:			
6.1.1.2	> Service Type (owner vs. non-owner) (Electric vs. another service)			
6.1.1.3	> Customer Type (residential versus commercial)			
6.1.1.4	> Billing Method (single premise versus aggregate)			
6.1.1.5	> Customer Credit Rating			
6.1.1.6	> Meter type or size (Commercial/Residential)			
6.1.1.7	Determine deposit(s) for a new customer based upon actual and potential liability. System will calculate a deposit for a customer based upon user defined criterion, customer class, credit history, etc.			
6.1.1.8	Determine additional or new deposit(s) for an existing account based upon: actual usage, payment history, credit score, etc.			
6.1.1.9	Provides the ability to accept and track a deposit on a customer account from a 3rd party agency.			

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6.1.1.10	Determine the deposit remittance approach: cash only, single billed amount, instalment billing, etc.			
6.1.1.11	For temporary service sites, the customer is required to pay a fee or deposit before delivery of meter or equipment (meter box/can, instruments). (HO currently handles this through the financial system)			
6.1.1.12	Bill/reverse security deposits based on OEB guidelines			
6.1.2	Deposit Types			
6.1.2.1	Accept electric and non-electric payments and deposits via cash, check, money order, visa, credit card and ACH and allow for posting to various GL accounts .			
6.1.2.2	Accept non-cash deposits such as bank letters, letters of credit history, surety bonds etc.			
6.1.2.3	Automatic assignment of deposit receipt numbers.			
6.1.2.4	Provides an expiration date of all non-cash deposits.			
6.1.2.5	Expired non-cash deposits will automatically create a notification document for customer renewal.			
6.1.2.6	Provides an audit trail of all non-cash deposits. User ID, date entered, value, .			
6.1.2.7	Provides for deferred deposit arrangements			
6.1.3	Multiple Deposits			
6.1.3.1	Deposit for a single product/service and across multiple products/services. A single deposit can be applied to an single service such as Electric, or a single deposit will be spread across multiple services such as Electric, Water.			

6.1.3.2	Deposit for a single account and across multiple accounts. A customer can apply a single deposit to cover multiple premises. (Non-Residential Accounts)			
6.1.3.3	System will indicate relationships between the accounts covered by the "blanket" deposit.			
6.1.4	Deposit Transfers			
6.1.4.1	Transfer existing deposit(s) to a new account. At the point of termination, a customer has the option to have their deposit transferred to their new billing account.			
6.1.5	Deposit Billing			
6.1.5.1	Capability of billing deposits in a single amount or several payments over a specified period of time. Each deposit payment will appear on the subsequent billings.			
6.1.5.2	Identification of outstanding deposits which have been assessed and billed but not yet collected.			
6.1.6	Deposit Review			
6.1.6.1	System provides the means to automatically, or at a user defined period, recalculate the default deposit required for each account and determine when deposit adjustments are indicated.			
6.1.6.2	The system will re-evaluate the deposit amount being held to determine if the account history indicates that a deposit reduction is appropriate.			
6.1.6.3	System provides the ability to approve each recommended deposit adjustment.			
6.1.6.4	System has the ability to bill the additional deposit adjustment amount on the next customer bill.			
6.1.7	Deposit Interest			

6.1.7.1	Interest calculations, calculation methods (simple & compounding), and accruals are determined by the user. Interest is applied to the deposit amount received.			
6.1.7.2	Interest can be paid at the time of each billing as a credit, or it can be accrued on the account and paid once a year.			
6.1.7.3	Maintains accurate interest earnings records for each bill interval, year-to-date earnings and total earnings.			
6.1.7.4	Report showing all deposit interest paid/accrued to customers.			
6.1.7.5	System allows deposit interest to be transferred to another account.			
6.1.7.6	Variance report showing all customers not receiving interest on their deposit.			
6.1.7.7	System can generate T5 slips for deposit interest paid out annually			
6.2	Payments			
6.2.1	Payment Sources			
6.2.1.1	Processing of cash in an on-line and batch mode.			
6.2.1.2	Indicate the method of payment on utility accounts (cash, cheque or credit card, Assistance Agency Payment, Money Order, Gift Certificate)			
6.2.1.3	Audit trail showing the source of payments, walk-in, mail, etc..			
6.2.1.4	Process payments from an on-line Cash Drawer			
6.2.1.5	Process direct mail payments			
6.2.1.6	Process payments from a Remittance Processor			
6.2.1.7	Process payments from a Lockbox (bank)			
6.2.1.8	Process payments from a Dropbox (Paystation)			
6.2.1.9	Process payments from ACH			
6.2.1.10	Process Credit Cards / Debit Cards			

6.2.1.11	Process Benefit Payments			
6.2.1.12	Process Field Collections.			
6.2.1.13	Process Pledges and Contributions.			
6.2.1.14	Process payments through Bank Drafting (PAP)			
6.2.1.15	Process payments from Payment Clearinghouse (Central Bank for PAP)			
6.2.1.16	Process payments from Third Party Vendor (e.g. Cable, Telephone, Gas, Water)			
6.2.1.17	Process payments from Kiosks			
6.2.1.18	Process payments from Pay Stations			
6.2.1.19	Process payments from G/L Transaction Only (merchandise for sale, paid upfront, not billed) (Currently handled through the financial system)			
6.2.1.20	Process payments from Internet			
6.2.1.21	Process payments from Smart Card (Prepaid Card)			
6.2.1.22	Process payments from EDI			
6.2.1.23	Process post dated checks (Note post dated checks)			
6.2.1.24	Process payments via scanners. The payments will have to be read via scanner.			
6.2.1.25	Provide the ability to capture the image of the check via the Remittance processor.			
6.2.2	Payment Reporting			
6.2.2.1	Generation of a cash payment receipt automatically after payment is received. (Walk-up window)			
6.2.2.2	Review of payment transaction history for "36" months.			
6.2.2.3	Identification and reporting of payments received on inactive accounts			
6.2.2.4	Identification and reporting of payments by payment type, drawer, pay station, Internet.			
6.2.2.5	Identification and reporting of payments by batch.			

6.2.3 Outstanding Account Balance			
6.2.3.1	Provide the ability to manually transfer balances on inactive accounts to new accounts. End-users did not transfer at the time the new account was set up.		
6.2.3.2	System will recognize payments received on an account that has a transferred service and automatically posts the payment to the account where the balance was transferred.		
6.2.3.3	System will automatically transfer terminated accounts final balance to a new account.		
6.2.4 Misapplied Payments			
6.2.4.1	Provides on-line cash corrections of misapplied and rejected cash.		
6.2.4.2	Reconcile unidentified payments.		
6.2.4.3	Provides the ability to link to the mis-applied payments.		
6.2.5 Payment Allocation			
6.2.5.1	Payments are applied to the customer account(s) in a user defined hierarchy which is parameter driven and easy to modify.		
	User defined rules to automatically apply to the distribution of partial payments may include:		
6.2.5.2	< Service Type		
6.2.5.3	< Service Provider		
6.2.5.4	< Percentage of Accounts Receivable		
6.2.5.5	< Line Item		
6.2.5.6	< Age of past due receivables		
6.2.5.7	< Payment Type		
6.2.5.8	< User defined		
6.2.5.9	Payment application based upon a customer request. Specifically apply a payment to an outstanding receivable, this would override any system parameters.		

6.2.5.10	System will handle overpayments in a defined manner such as hold till next billing, or automatic overpayment check. Would like the flexibility if necessary.			
6.2.5.11	Provides on-line reapplication of payments.			
6.2.5.12	The hierarchy must accommodate partial, full, and over payments across the various receivable types. Payments may be allocated by percentage or priority across multiple utility services and product contracts.			
6.2.6 Cash Balancing & Reconciliation				
6.2.6.1	Cash must be balanced daily. System will balance for both total dollars received and the number of items by payment method.			
6.2.6.2	Cash drawer processing and cash reconciliation is provided for each cashier. System will allow a cashier to balance their own drawer if their security level permits.			
6.2.6.3	A consolidated cash report is interfaced with G/L. Interface between the modules is electronic or manually entered from the consolidated report.			
6.2.6.4	Payment transaction should be provided to handle multiple bank accounts.			
6.2.6.5	Entry of updates/corrections for bank reconciliation information. Upon recognition of an error, a Utility representative can manually make a correction to a single payment or batch.			
6.2.7 Payment Posting				
6.2.7.1	Immediately reflect payments received from on-line cash on the customer's account. Overnight processing is not required to view the most recent transaction.			

6.2.7.2	Apply a single payment over multiple accounts. Master accounts paying with a single check, the System must accommodate distributing the payment across multiple sub-accounts.			
6.2.7.3	Post payments to accounts which have been written-off.			
6.2.8	Payment Transfers			
6.2.8.1	Transfer payments from one account to another with the ability to review audit trail.			
6.2.9	Payment Adjustments			
6.2.9.1	Provide ability to process payment adjustments on-line.			
6.2.10	Payment Discounts			
6.2.10.1	Tracking of customer payment dates in order to identify customers who pay their bills immediately upon receipt or within a specified period of time.			
6.2.10.2	System will accommodate for advanced cash payments based upon last billed charges and associated allocation.			
6.2.10.3	System will provide flexible discounts for advanced cash payments. Discount amount and date will print on the customer bill, in addition to the regular due date and amount. Flexible discounts may include: senior citizens, commercial accounts, etc.			
6.2.10.4	Optionally a percentage discount or incentive, or flat fee credit would be applied to the next bill for those customers paying immediately.			
6.2.11	Returned Checks			
6.2.11.1	On-line review or report of returned check information. Report would include: Customer name, service address, amount, date, etc.			

6.2.11.2	Provide for on-line processing of returned checks with an interface into the customer system to reapply the charges.			
6.2.11.3	System will maintain a history of the number of bad payments received on an account.			
6.2.11.4	When a reversal of the payment has been applied, the system will return the account to its original position in the delinquency process after adjusting for the number of days since the bad payment was received.			
6.2.11.5	Provide for service charges with flexibility to easily modify the charge			
6.2.12	Receivables			
6.2.12.1	On-line viewing and report of the accounts receivable transactions by type by customer. Report can be segmented by customer class, or by receivable such as Electric, Taxes, Water, Fees.			
6.2.12.2	On-line view and report of the aging of accounts receivable for all accounts by receivable type by customer. Aging segments may be 30, 60, and 90.			
6.2.12.3	On-line view and report of the aging of Receivables for accounts by customer segment (customer class, product).			
6.2.12.4	On-line view and report of the total Receivables by customer segment (Class, SIC).			
6.2.12.5	On-line view and report of the aging of Receivables for accounts by dollar amount.			
6.2.12.6	A daily aging calculation with viewing of aged accounts receivable including a stratification of accounts by various payment status.			
6.2.13	Voluntary Contributions			
6.2.13.1	Provides directed cash contributions to special programs.			

6.2.13.2	Provide the ability to track and report on customer giving contributions.			
6.2.13.3	Provide the ability to track and report on customers who have received donations from the contributions and pledges.			
6.2.13.4	System will identify to CSR an account that qualifies to receive special payment assistance.			
6.2.13.5	CSR can define information as the source of the contribution, the pledge amount and the date the contribution was made.			
6.2.13.6	Special accounts can receive contributions from multiple sources.			
6.3	Refund Processing			
6.3.1	When refunds are made, the system makes the appropriate journal entry(s) to the general ledger, and performs other associated transactions.			
6.3.2	Deposit Refunds			
6.3.2.1	Provides for automatic deposit refunds to active customers based upon: credit history and length of time the deposit has been on file.			
6.3.2.2	System will automatically apply or refund a customer deposit when the account is terminated. The deposit will apply to the current charges prior to printing a bill.			
6.3.2.3	Provides an audit trail of all deposits and application of the deposit.			
6.3.2.4	On-line view or report of all deposits applied and refunded.			
6.3.3	Overpayment Refunds			
6.3.3.1	Automatically identify and flag within "x" number of days the overpayment on a final account.			
6.3.3.2	Automatically on a transfer within the service territory within "x" number of days transfer the overpayment to the new account.			

6.3.3.3	Ability to override any overpayment refund or transfer. System will allow manual intervention to prevent an accounts payable transaction.			
6.3.3.4	Refund an overpayment on an active account, (the customer made a duplicate payment).			
6.3.4	Credit Refunds			
6.3.4.1	Provide the ability to pay credit balance refunds to the customer. System will alert to all customers maintaining a credit balance.			
6.3.4.2	Calculate mass rate credit/refunds according to parameters such as: customer class, account status, rate schedule, effective dates, geographical area, and other rate determinants.			
6.3.4.3	Validate the amount of the refund given to each customer against a predetermined parameter. System will check for any "large" refund payments.			
6.3.4.4	Review the bad debt and charge-off ledger prior to rendering a refund check amount to the customer. Ability to specify search parameter to identify bad debt customer.			
6.3.4.5	Apply the refund directly to the customer account, cut a refund check, or a combination of the two based upon customer preferences.			
6.3.4.6	Track and provide adequate control over refund checks. System maintains checks and balances when printing refund checks.			
6.3.4.7	Ability to generate refund reports based on variable parameters such as: customer class, account status, rate schedule, effective dates, geographical area, other rate determinants.			
6.3.5	Check Writing			

	System will allow the Utility CIS to create/write checks for a variety of reasons including:			
6.3.5.1	> Deposit Refunds			
6.3.5.2	> Credit Refunds			
6.3.5.3	> Load Management Refunds			
6.3.5.4	> Special Customer Requests			
6.3.5.5	System allows check generation or provides an interface to another system for check generation, such as an accounts payable system.			
6.3.5.6	System allows for information contained on the check to be easily configured by the user set-up process. Examples of the type of information to be printed with the check include:			
6.3.5.7	> Check number			
6.3.5.8	> Description or purpose of check			
6.3.5.9	> Check print date			
6.3.5.10	> Check amount			
6.3.5.11	> Customer/Account information (Account Number)			
6.3.5.12	System allows authorized users the ability to manually generate checks on-line in order to meet a customer's immediate request for a check. (Deposit Refund)			
6.3.5.13	System will track check bank account information, check numbers, and check dates.			
6.3.5.14	System allows authorized users the ability to void a previously generated check.			
6.3.5.15	System's check reconciliation process is capable of being scheduled to be performed automatically and/or to be performed upon demand.			

6.3.5.16	System will maintain a check register available on-line that includes the ability to provide subtotals by categories such as dates and purpose.			
6.3.5.17	System is easily customized for printing different check formats.			
6.3.5.18	System will provide the appropriate accounting interface to accurately debit/credit various accounts as checks are processed, i.e.. issued, reissued, voided, etc.			
6.3.6	Unclaimed Property Refunds			
6.3.6.1	System allows checks that have been issued and not presented for payment within a user defined number of days of issue to be placed in an unclaimed moneys account. Unclaimed moneys are held for specified period and then forwarded to the proper agency.			
6.3.7	Rebates			
6.3.7.1	Processing of mass customer rebates			
6.4	Financial Interfaces			
6.4.1	Standardized Financial Management Interface			
6.4.1.1	Provides an automatic interface to the General Ledger/Financial Management System. The timing on this interface is user defined (daily, weekly, monthly, etc.)			
6.4.1.2	Journalize revenues/accruals, receivables, etc., of billed and unbilled consumption and products and services into the General Ledger.			
6.4.1.3	Reconciliation of CIS revenue cycle with the G/L receivable cycle.			
6.4.1.4	A user defined accounts receivable reconciliation by service, by cycle day.			
6.4.1.5	A (user defined) transfer of revenues and taxes.			

6.4.1.6	Internal financial controls and balancing is provided.			
6.4.1.7	Prepare financial reports			
6.4.1.8	Provides for an automatic interface to G/L accounts payable for processing credit refunds.			
6.4.1.9	Provides the ability to download a revenue file for analysis that includes both monthly and cumulative information of the following: Account number, office code, meter number, taxes, usage kWh, kW, total billed amount, etc. (Need to be able to report to the OEB)			
6.4.1.10	Automated monthly calculation for unbilled revenue			
6.4.1.11	Automated recalculation of prior months' unbilled revenue estimate using first actual customer consumption data following the month's estimate.			
6.4.2	Financial - Bad Debt			
6.4.2.1	Review Bad Debt Write-offs and journalize			
6.4.2.2	Accommodate financial year-end (user defined time-frame) write-off for receivables			
6.4.2.3	Determine value of the accounts receivable asset			

End of Section

Table 10.2.8. Inventory Management

7.0 Inventory Management				
Item	Function / Feature	Vendor Score	Comments	Work Effort
7.1	Meter Entity			
7.1.1	Meter Identification and Access			

7.1.1.1	Does not allow duplicate meter numbers within the same utility type. If duplicate meter numbers occur across manufacturers the system provides a method to differentiate the meters.			
7.1.1.2	Capability of using utility based meter numbers. (alpha or numeric)			
7.1.1.3	An on-line search capability is supported. Including:			
7.1.1.4	> Premise or Location Number			
7.1.1.5	> Utility Assigned Meter Number			
7.1.1.6	> Dimensional Location (x,y Coordinates)			
7.1.1.7	> Manufacturer and Model			
7.1.1.8	> Meter Type and Size			
7.1.1.9	> Customer Name or Number			
7.1.1.10	> Account Number			
7.1.1.11	> Meter Order Number			
7.1.1.12	> Read Route Number for specific services. (Cycle/Route/Walk)			
7.1.1.13	> Purchase Date			
7.1.1.14	> Search on battery year.			
7.1.1.15	> Itron ERT serial number			
7.1.1.16	Provide the ability to scroll forward and backward in meter inventory			
7.1.2 Meter Status				
	Provide for statusing of the meters. Including:			
7.1.2.1	> Inventoried (Meter Shop)			
7.1.2.2	> Service (Active)			
7.1.2.3	> Service (Inactive)			
7.1.2.4	> In Shop (meter shop)			
7.1.2.5	> Information Meter (Meter Seal data)			
7.1.2.6	> Meter Stolen/Missing			
7.1.2.7	> Damaged			
7.1.2.8	> On Truck			
7.1.2.9	> Scrapped			
7.1.3 Meter Notes				
7.1.3.1	Provide for free form meter notes. Notes will be maintained over the life of the meter.			

7.1.3.2	Provide options for sorting and displaying notes.			
7.1.3.3	Provide an automatic delete date on a note.			
7.1.3.4	Provide for the identification of critical notes which "flag" the meter. (i.e. for an example a service order)			
7.1.3.5	Provide author information for example: User ID, date, etc.			
7.1.4 Meter Location				
7.1.4.1	Identify all locations the meter has been set. System will automatically track the history of installations for a meter.			
7.1.4.2	Identify all meters set at the location. Meters can be identified for each service and service point.			
7.1.4.3	Tracking of all meters and their current location.			
7.1.4.4	Provide viewing of meter set components by: Components Age, Components Manufacturer, Meter Numbers (Manufacturer/Utility), Meter Type, Received Date, Date Removed, Date Installed, AMPS, Volts, Phase, Wire, KH, RR, Dials, CT/PTs, Solid State or Mechanical .			
7.1.4.5	Track stolen meters and the location from which they were stolen.			
7.1.4.6	Ability to track meters at locations that are not being used for billing purposes (i.e. redundant meters, back-up meters)			
7.2 Meter Types				
	The system will accommodate the following meter types:			
7.2.1	> Electric Meters			
7.2.2	> Water/Gas Meters			
7.2.3	> Load Research Meters			
7.2.4	> End Use Meter (real time meter)			
7.2.5	> Demand Meters			
7.2.6	> KVAR / KVA/ KWH Meters			
7.2.7	> Private Meters			

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7.2.8	> Master Meters (Bulk Meter)			
7.2.9	> Sub Meters (Add/Subtract Meters)			
7.2.10	> Time of Use Meter			
7.2.11	> Off- Peak meters			
7.2.12	> Interval/ Smart meters			
7.3	Meter Attributes			
7.3.1	Provides table validation of all meter attributes including cross field validation on specific components, for example multipliers and meter size validation.			
7.3.2	Electric Meter Attributes			
	The on-line review and update of all meter attributes and engineering information. Attributes may include:			
7.3.2.1	> Service address or Location			
7.3.2.2	> Meter Number			
7.3.2.3	> CT or PT device			
7.3.2.4	> Last seal date			
7.3.2.5	> Last service date			
7.3.2.6	> Transponder identification (ERT Number)			
7.3.2.7	> Meter Manufacturer			
7.3.2.8	> Meter Type			
7.3.2.9	> Meter Multiplier			
7.3.2.10	> Meter Cost			
7.3.2.11	> Meter Installation Cost			
7.3.2.12	> Reverification Date			
7.3.2.13	> KVA Meter Number for accounts its power factors			
7.3.2.14	> Number of Dials / type (digital, cycle ometer, decimal point)			
7.3.2.15	> Purchase Date			
7.3.2.16	> Installation Date			
7.3.2.17	> Seal Group updates			
7.3.2.18	> Last Test Date (all test dates)			
7.3.2.19	> Software Revision Code (for software controlled meters)			
7.3.2.20	> Number of Elements			
7.3.2.21	> Single or Three Phase			
7.3.2.22	> Voltages			
7.3.2.23	> Register Ratio			

7.3.2.24	> Class (Amperage Capacity)			
7.3.2.25	> Battery year			
7.3.2.26	> Itron ERT			
7.3.2.27	> Phone Number (Meters with modems)			
7.3.2.28	> CCA Number (Record of installation number)			
7.3.2.29	> Other user defined fields			
7.3.2.30	> Meter Base (socket meter etc)			
7.3.2.31	> Stock code number			
7.3.2.32	> Wire			
7.3.2.33	> Sample group number			
7.3.2.34	> Meter associated attributes (i.e. what is associated with the meter...)			
7.3.2.35	> Meter KI			
7.3.2.36	> Meter reading (in/out/check reading)			
7.3.2.37	> SO Number			
7.3.2.38	> Transformer data (transformer number, serial number, rate and voltage, primary amperage, secondary amperage, ratio, dual ratio, wire)			
7.3.2.39	Identify the power transformer or transformer bank associated with an in-service meter.			
7.3.2.40	Recorder ID's			
7.3.2.41	KT weight for interval			
7.4	Current Potential Transformers			
7.4.1	purchase date			
7.4.2	cost			
7.4.3	Manufacturer			
7.4.4	Type			
7.4.5	rate and voltage			
7.4.6	primary voltage			
7.4.7	secondary voltage			
7.4.8	primary amperage			
7.4.9	secondary amperage			
7.4.10	test date			
7.4.11	ratio number 1,2			
7.4.12	Marked Ratio			
7.4.13	Date installed			
7.4.14	SO Number			
7.4.15	Installer Number			

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7.4.16	Date Out			
7.4.17	Location			
7.4.18	Last Cross reading date (Check reading)			
7.4.19	Stock code number			
7.5 Meter Based Inventory Activities				
7.5.1 Received Into Inventory				
7.5.1.1	System provides the means for authorized users to create and maintain an accurate inventory of the meters in stock.			
7.5.1.2	Allow mass entry of meters with automatic assignment of sequential meter/equipment numbers by manufacturer and meter/equipment type.			
7.5.1.3	Provide ability to upload (for example, from a diskette) meters from the manufacturer to go into a "pending inventory". Allow mass assignment of sequential meter numbers. (ERT meter upload.. Not sequential)			
7.5.1.4	Allow for addition of single meters to inventory.			
7.5.1.5	Provide ability to interface with bar code readers for bar-coded meter numbers on the meter or equipment.			
7.5.2 Deleted From Inventory				
7.5.2.1	Allow mass deletion of meters from inventory.			
7.5.2.2	Allow for deletion of single meters from inventory.			
7.6 Meter Testing				
7.6.1	Provide for testing of other Third Party meters.			
7.6.2 Testing Identification				
7.6.2.1	Support a routine testing program.			
7.6.2.2	Maintain sample test groups			
7.6.2.3	Maintain CT/PT information.			

7.6.2.4	Generate a maintenance service order based on next meter test date or scheduled maintenance date.			
7.6.2.5	Indicate on the service order the need to exchange the meter based on a random sample test, age of meter, or other test determination. Update the attributes of the meter test group. (indicate all pertinent meter information on SO)			
7.6.2.6	Indicate testing of meters on "x" period (parameter driven) is required and generate an order to field test the meter.			
7.6.2.7	Service Orders will be created as required.			
7.6.2.8	Identify meters for testing based on user defined criteria. Electric meters and water meters have different recall criteria, therefore must be flexible.			
7.6.3	Testing Results			
7.6.3.1	System will provide a mechanism to record test results. Results include: test date, tester name. (All relevant test information to be included)			
7.6.3.2	System allows for a comment message to be associated with the meter test.			
	System maintains meter test history that contains the following items:			
7.6.3.3	> Date submitted for test			
7.6.3.4	> Initials of person performing test			
7.6.3.5	> Test results			
7.6.3.6	> Date test completed			
7.6.3.7	> Reason for test			
7.6.3.8	> Test procedure performed			
7.6.3.9	> Comments			
7.6.3.10	> Meter problem code			
7.6.3.11	> Person requesting test			
7.6.3.12	> Meter reading			
7.6.3.13	Must support recording of multiple test results for a given test scenario. (e.g. electric--light load/ full load,)			

7.6.3.14	Provide a credit or a charge to the customers account based upon the results of the customer requested meter test. (Utility driven Parameters)			
7.6.3.15	System notification when the meter tests out of range.			
7.7	Electric Meter Interface			
7.7.1	Provide integration with an Electric Meter Management System . (Hand Held equipment)			
	Equipment Inventory			
7.8	Equipment Entity			
7.8.1	Equipment Identification and Access			
7.8.1.1	Duplicate equipment id numbers are not allowed.			
	An on-line search capability is supported. Including:			
7.8.1.2	> Premise or Location Number (Address)			
7.8.1.3	> Equipment Identification Number			
7.8.1.4	> Equipment Manufacturer or Number			
7.8.1.5	> Customer Name or Number			
7.8.1.6	> Account Number			
7.8.1.7	> Meter Type (JS5, Alpha, AXS4)			
7.8.1.8	> Transformer Number			
7.8.1.9	> User defined fields			
7.8.1.10	> Date of purchase			
7.8.1.11	> Date of install			
7.8.1.12	> Cost			
7.8.1.13	> Water meters- spindles and dials			
7.8.2	Equipment Status			
	Provide for statusing of equipment. Including:			
7.8.2.1	> Inventoried			
7.8.2.2	> Service (Active)			
7.8.2.3	> Service (Inactive)			
7.8.2.4	> In Shop			
7.8.2.5	> Equipment Stolen/Missing			
7.8.2.6	> Equipment Damaged			
7.8.2.7	> Equipment On Truck			
7.8.2.8	> Equipment Retired / Junked			
7.8.2.9	> Equipment sold date			

7.8.2.10	> User defined fields			
7.8.3	Equipment Location			
7.8.3.1	Identify all locations the equipment has been set.			
7.8.3.2	Tracking of equipment and their current location.			
7.8.3.3	Track stolen equipment and the location from which they were stolen.			
7.9	Equipment Types			
7.9.1	Electric Based Equipment			
7.9.1.1	Accommodate electric related equipment			
7.10	Equipment Based Billing Activity			
7.10.1	Equipment Installation			
7.10.1.1	The equipment installation will automatically update equipment inventory and attribute values.			
7.10.2	Equipment Exchange			
7.10.2.1	The equipment exchange will automatically update equipment inventory and attribute values.			
7.10.3	Equipment Removal			
7.10.3.1	The equipment removal will automatically update equipment inventory and attribute values.			
7.11	Equipment Based Inventory Activity			
7.11.1	Acquire Equipment			
7.11.1.1	Provide the ability for mass receipt and addition of equipment into inventory.			
7.11.2	Retire Equipment			
7.11.2.1	Provide for retirement of equipment.			
7.12	Distribution Transformer Inventory			
	Provide inventory tracking for distribution transformers:			

7.12.1	Transformer Status: in stock, in service, scrapped, issued to service, in repair			
7.12.2	Transformer Attributes to include: Manufacturer, serial number, primary voltage, secondary voltage, winding type, part number, impedance, power, weight, phase, tap settings, date of receipt, original cost, transformer type (per LH naming convention)			
7.12.3	Provide a history of locations where transformer has been located			
7.12.4	Ability to perform partial searches based on transformer attributes, location, part number and status.			
7.12.5	Provide mechanism to track various test histories including PCB tests.			
7.12.6	Provide user defined comments to be entered			
7.12.7	Provide audit trail of user updates and changes			
7.12.8	Provide ability to associated transformer location information to transformer attribute			
7.12.9	Provide mechanism to track associated equipment to the transformer record (high tension switches, breakers, etc).			
7.12.10	Provide ability to enter into inventory physical transformer records through bar code technology			
7.12.11	Provide various audit reports tracking transformer inventory movement			
7.13	Transformer Location			
7.13.1	Ability to assign structured service address components and geographic information to location profile to enable users to find location			

7.13.2	Provide the following attributes: transformer location type prefix (LH naming convention), numeric number, Feeder information, upstream feeder information, location status (in service, issued, abandoned), phase indicators, grid location, mapping information.			
7.13.3	Ability to link distribution transformer records to transformer location records			
7.13.4	Ability to link service points to transformer location records			
7.13.5	Ability to perform mass updates to service points connected to transformer location. (when services are moved from one location record to another).			
7.13.6	Provide freeform comments to be entered on transformer location record.			
7.13.7	Provide mechanism to track non-metered services to the location record such as traffic signal or streetlight circuits.			
7.13.8	Provide a history of all transformer's that have been at the location			
7.13.9	Ability to perform partial searches based on transformer location attributes including address and service identifiers			
7.13.10	Ability to create reports listing transformer location and transformer record attributes including customer information			
7.13.11	Provide alert to users advising of life support customers attached to transformer location profile.			
7.13.12	Transformer specific loss factors for billing of customers attached to the transformer			
7.14	Other Inventory			
7.14.1	Tracking of communication devices			

7.14.2	Tracking of related equipment including attributes, status, location, etc			
7.14.3	Maintain inventory of customer keys for reading inaccessible meters.			
7.14.4	Provide online update capabilities for key management.			

End of Section

Table 10.2.9. Portfolio Management

8.0 PORTFOLIO MANAGEMENT				
Item	Function / Feature	Vendor Score	Comments	Work Effort
8.1	Service Offerings			
8.1.1	Accommodates Electric Service			
8.1.2	Accommodates special negotiated service contracts			
8.1.3	Accommodates unbundled service contracts.			
8.1.4	Accommodates standby service contracts.			
8.1.5	Accommodates co-generation service contracts.			
8.1.6	Accommodates firm service contracts			
8.1.7	Accommodate Interruptible contracts			
8.1.8	Accommodate miscellaneous service contracts			
8.1.9	Accommodate non-portfolio power service			
8.1.10	Accommodates Water/Gas Service			
8.1.11	Accommodates Wastewater Service			
8.1.12	Accommodates Solid Waste Service			
8.1.13	Accommodates Recycling Service			
8.1.14	Accommodates Storm Drainage Service			
8.1.15	Accommodates City Services (e.g. street sweeping, transportation)			

8.1.16	Accommodates Power Marketing, the ability to sell and purchase power to outside customers.			
8.2	Equipment Offerings			
8.2.1	Accommodates Recycling Containers			
8.2.2	Accommodate Refuse Containers			
8.2.3	Accommodate Electric Infrastructure Equipment			
8.2.4	Accommodate the servicing of equipment			
8.3	Program Offerings			
8.3.1	Provides a bad debt payment arrangement program			
8.3.2	Provides a customer deferred payment agreement program			
8.3.3	Provides a Landlord / Owner/ Third Party agreement program.			
8.3.4	Provides a special large complex program to support continuous service between tenants and owners, landlords, or management companies.			
8.3.5	Provides a low income assistance agreement program.			
8.3.6	Provide a senior discount program			
8.3.7	Provides a bank drafting or credit card drafting, and all electronic payment programs, payroll deduct.			
8.3.8	Conservation Programs			
8.3.8.1	Provides a bank drafting or credit card drafting, and all electronic payment programs, payroll deduct.			
8.3.8.2	Provide the ability to identify participation in energy conservation programs by type of program (lighting, etc.), date and amount of rebate if any.			
	End of Section			

Table 10.2.10. Rates Management

9.0 Rates Management				
Item	Function / Feature	Vendor Score	Comments	Work Effort
9.1	Rate Processing			
9.1.1	On-line creation of new rate structures. Programming is not required.			
9.1.2	On-line identification and copying of current/historical rate structures to new rate structures.			
9.1.3	On-line deletion of old rate structures for unused rate structures with controls over the deletion process.			
9.1.4	Provide an inactive rates file.			
9.1.5	Ability to modify a rate and track changes for purposes of historical modeling and billing.			
9.1.6	Ability to track the customers historical rate assignments.			
9.1.7	Selection and viewing/printing of rate structures and entire rates master as required.			
9.1.8	On-line entry and maintenance of table driven rates and fees.			
9.1.9	Provide for special negotiated rates.			
9.1.10	Provide rate schedules by service type and service point for: electric, Gas, water, wastewater, drainage, solid waste, recycling, and other city services.			
9.1.11	Allow multiple rate changes within a billing period with proration reflected on the customer's bill.			

9.1.12	Provide for general rate reporting for example allow reporting of consumption used and dollars received at the rate step level per individual customer and across the utility.			
9.2	Rates			
9.2.1	Accommodate a Block Rate Steps (declining, inverted, minimum)			
9.2.2	Accommodate a Two-Part Rate (energy & demand charges)			
9.2.3	Accommodate a Three-Part Rate (customer, energy & demand charges).			
9.2.4	Accommodate an Unbundled Component Rate (Commodity, Transportation, Storage, Distribution, Metering, Billing, etc.)			
9.2.5	Accommodate a Time-of-use Rate			
9.2.6	Accommodate a Real Time Pricing Rate			
9.2.7	Accommodate a Seasonal Rate			
9.2.8	Accommodate an Interruptible Rate			
9.2.9	Accommodate a Ratchet Rate			
9.2.10	Accommodate a rate based on input from another service			
9.2.11	Accommodate an Incentive/Discount Rate			
9.2.12	Accommodate Geographic Distinction Rates			
9.2.13	Accommodate Rate Caps			
	Individual rate schedules may contain the following information for bill calculation:			
9.2.14	> Consumption Blocks and Rates			
9.2.15	> Estimated Bill Percentage (increase estimated bill by a %)			
9.2.16	> Customer Charge and Proration Indicator (by rate class)			
9.2.17	> Customer Charge Multiply by Number of Dwelling Unit Indicator			
9.2.18	> Minimum charge and Proration Indicator			

9.2.19	> Fixed Charge and Proration Indicator			
9.2.20	> Default Average Usage (Winter Average)			
9.2.21	> Late Charge Amount by geographical area.			
9.2.22	> Late Charge Percentage by geographical area.			
9.2.23	> Flat Rate Discount Amount by geographical area.			
9.2.24	> Flat Rate Discount Percentage by geographical area.			
9.2.25	> State Tax Percentage by geographical area.			
9.2.26	> City Tax Percentage by geographical area.			
9.2.27	> Other Municipal Tax Percentage by geographical area.			
9.2.28	> Number of Billing Periods Per Year (capable by service)			
9.2.29	> Provide for a customer specific (or service address specific) discount factor. For each type of service billed.			
9.2.30	> Provide for Senior Discount Rate			
9.2.31	To accommodate unlimited GL accounts for all rate components. (GL number for each GL component. (By Class, FERC account, etc.)			
9.2.32	Accommodate site specific loss factors			
9.2.33	Accommodate negative rate category (providing a credit rather than debit to service--generation supplied to LDC, etc)			
9.2.34	Ability to prevent accounts from estimating consumption based on rate category (i.e. demand)			
9.3	Special Rates			
9.3.1	Ability to accommodate through the rate table, applying a percentage to the units of consumption measured, and then billing that portion at a specific rate.			

9.3.2	Ability to accommodate through the rate table, taking the difference between a user-defined contracted minimum unit of measure and the actual unit of measure to be billed.			
9.3.3	Ability to accommodate through the rate table, billing the remaining portion of the unit of measure measured, at a different specific rate.			
9.3.4	Rate table variables may include: kW, kWh, KQ, KVAR, KVA percent to bill, fixed rate, economy rate, and minimum kW. (Or other unit of measure)			
9.4 Charges and Fees				
9.4.1	Provide for one-time charges, e.g.: Reconnect Charge Fee, Turn-on Fee, Late Charge Penalty, Return Check Fee, After Hours Fee, Initiation Fee, Broken Lock Fee, Meter Accuracy Test Fee, etc.			
9.4.2	Provide for recurring charges.			
9.4.3	Provides for a means for identifying accounts that qualify for a recurring charge or credit, for example an account participating in a load management program.			
9.4.4	Allows for establishment of a beginning and end date for these charges and uses these dates to determine if the charge or credit should be billed.			
9.4.5	Provide for the creation of user-defined one-time miscellaneous charges.			
9.5 Surcharges				
9.5.1	Provide for multiple surcharges (Charge or Credit) such as Power Factor Adjustment, Power Quality Rate,			
9.5.2	Provide for Special Surcharges			

9.5.3	Provide for surcharges when a customer consumes more than the account has been allotted.			
9.5.4	Provide for Environmental Costs such as the Environmental Protection Fee.			
9.5.5	Provide a surcharge specific to a premise with a defined start and end date.			
9.5.6	Provide for Other Surcharges as they are identified.			
9.6	Taxes			
9.6.1	Provide for the set-up and assignment of State Taxes... (GST)			
9.6.2	Provide for the set-up and assignment of Local Taxes			
9.6.3	System allows for the tax calculation to be different for each taxing entity and service type.			
9.6.4	System allows for different tax rates based on geographic location.			
9.6.5	Provide for the set-up and assignment of Other Taxes			
9.6.6	On-line set-up and maintenance of tax categories and codes with associated tax rates based on percentage or usage, include with charges on bill, and appropriate G/L number			
9.6.7	System has the ability to track and report accounts and amount levied by specified taxing entity.			
9.7	Exemptions			
9.7.1	Provide for Tax Exemptions			
9.7.2	Provide for Fee Exemptions			
9.7.3	Provide ability to report on tax exempt customer/location.			
9.7.4	Provide ability to report on tax exemption type.			
9.8	Adjustment Clauses			

9.8.1	Provide the ability to include a Monthly Fuel/ Purchase Power Adjustment Clause/ Hydro credit as a part of the monthly electric charges. (For specific customer classes)			
9.9	Rate History			
9.9.1	Provide browsing and review of inactive/historical rates			
9.10	Rate Determinants			
	Specific information will be utilized as rate determinants in determining the correct rate to be assigned. Determinants may include:			
9.10.1	> Rate Schedule Unique Identifier (Rate Code)			
9.10.2	> Meter Size			
9.10.3	> Inside/Outside City Limit			
9.10.4	> Customer Classification/Trade Class			
9.10.5	> Geographical Area			
9.10.6	> Property Usage Category (per service)			
9.10.7	> Property Size			
9.10.8	> Master Meter			
9.10.9	> S.I.C. Code			
9.10.10	> Special Discount (elderly, disabled, low income)			
9.10.11	> Power Usage Equipment			
9.10.12	Service Size - Water Rates			
9.10.13	Flat charges - Sewer Rates			
9.11	Dynamic Rate Assignment			
9.11.1	Provide monthly dynamic assignment of electric rates based upon quality of electricity.			
9.11.2	Provide the ability to adjust the electric rate according to the quality of the electric by geographic area.			
9.11.3	Provide for an interruptible reduced rate based upon the amount of interruptions during the month.			

9.11.4	Provide monthly dynamic assignment of electric rates based upon monthly consumption.			
9.12	Automatic Rate Assignment			
9.12.1	Automatic assignment of rates based upon defined rate determinants. (i.e. - account type)			
9.12.2	Ability to override rates which the system may automatically assign.			
9.12.3	Provide the ability to override rate determinants at individual customer/premise.			
9.13	Rate Development			
9.13.1	Allows for calculation of sample billings for test accounts without affecting revenue. (No test system necessary)			
9.13.2	Provides comparative analysis of alternate rates for the customer based on past and/or anticipated consumption.			
9.13.3	Accommodates proposed rate changes without affecting the customer record.			
9.13.4	Provisions exist for projecting revenues from new rate structures based on affected classes of customers by rate component.			
9.13.5	Provide the ability to track weather conditions such as average temp. to account for low revenues, address customer high bill complaints, or for use in estimating, and revenue projections.			
9.13.6	Provide a reporting method for analysis of current rate structures to provide revenue and bill frequency analysis (number of bills and consumption).			

9.13.7	Provides the ability to download for the analysis of customer usage by various characteristics for example: customer class, usage category, S.I.C., demand, load factors, etc.			
9.13.8	Provincial Benefit & RPP True Up			

End of Section

Table 10.2.11. Service Address Management

10.0 SERVICE ADDRESS MANAGEMENT				
Item	Function / Feature	Vendor Score	Comments	Work Effort
10.1	Service Address Entity			
10.1.1	Service Address Identification and Access			
	A search capability provides keyword and partial search on all components of the service address. A service address can be identified by:			
10.1.1.1	> Premise or Location Number			
10.1.1.2	> Keyword or Phrase (First Bank Building)			
10.1.1.3	> Intersecting Roads			
10.1.1.4	> Meter/Equipment Number			
10.1.1.5	> Dimensional Location (x,y Coordinates) (GIS)			
10.1.1.6	> Legal Parcel Number			
10.1.1.7	> Geopolitical Area (e.g. Taxing Authority, Sales Territory, Franchise Rule, Capital District Code, Local improvement tax)			
10.1.1.8	> Service Address components			
10.1.1.9	> Read Route Number for any service.			
10.1.1.10	> Wards Boundaries			
10.1.1.11	> Subdivision name, apartment name, etc.			
10.1.1.12	> New Line Extensions			
10.1.1.13	> Date of Service for the Address			

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10.1.1.14	> Date First/Current Meter Set			
10.1.1.15	Provide the ability to convert old folio/premise ID and track in new system and provide search capability.			
10.1.2	Service Address Components			
10.1.2.1	The service address is standardized into components.			
	Components include:			
10.1.2.2	> House Number			
10.1.2.3	> Fraction/Extension			
10.1.2.4	> Prefix			
10.1.2.5	> Street Name			
10.1.2.6	> Street Type			
10.1.2.7	> Suffix			
10.1.2.8	> Space Number (apt, suite, bldg, lot, condo)			
10.1.2.9	> City			
10.1.2.10	> Province / State			
10.1.2.11	> Country Code			
10.1.2.12	> Postal Code (To Include Carrier Route)			
10.1.2.13	> Misc description location (Pool, garage etc.)			
10.1.2.14	Provide ability to create 'no address' relationships (i.e. n/w corner Main and First). These are not structured addresses as above.			
10.1.2.15	able to validate on a list of authorized street names			
10.2	New Service			
10.2.1	Automatically assigns a premise or property id or service address id number for new service addresses.			
10.2.2	Validation of street names within city or revenue area exists for establishment of the customer premise. New service cannot be provided to a non-existent street name.			

10.2.3	Allow entry of new service address information on a partial basis, the system understands the address is pending activation following successful completion of construction activities (when a subdivision is created).			
10.2.4	Establish multiple customer premises for a single legal parcel (e.g. shopping mall).			
10.2.5	Allows for tracking utility services to temporary sites including: construction sites, fairs, Christmas tree lots, or other similar uses where the installation of a permanent service connection is considered impractical.			
10.2.6	Establish and track premises and facilities by specific entity, geographical, or branch office.			
10.2.7	Establish infrastructure items (meters, utility poles, etc) not associated with a billing service address (from the valid address file).			
10.2.8	Design / Installation Interface			
10.2.8.1	Edit criteria to require a mailing address with a specific service type or class of service or rate.			
10.2.8.2	Establish customer premises not in the service territory to accommodate sales within the competitive retail market.			
10.2.8.3	Requests for new service can be routed to the work management system (generation of a work request) for design and cost estimation. The customer can then be quoted a price for new service or extensions on existing service.			

10.2.8.4	Identify accounts inactive over "X" by work district and generate service orders to remove the meter/equipment from the vacant location. The amount of time elapsed should vary by service and notification.			
10.2.9	Design Interface			
10.2.9.1	Input service requirements including: service size, voltage and building details as applicable			
10.2.9.2	Allow for the generation of an inspection order.			
10.2.9.3	Provide consumption data to calculate load on equipment.			
10.2.9.4	Integration with Work Management System to update service size, voltage and building details from permits.			
10.2.9.5	Match existing customers load with proposed customer load based on type of business and character of business.			
10.2.9.6	Integration with work management system to update the status or condition of service			
10.2.9.7	Maintain a cross reference to applicable contracts and customer agreements (e.g. ESA's & TSA's)			
10.2.10	Installation Interface			
10.2.10.1	Record the customers preferred outage time and pass to the work management system.			
10.2.10.2	On-line viewing of customer contact information for switching.			
10.2.10.3	Update the service address with actual site specific information from the Work Management System.			
10.2.10.4	Update the status of the new service work order to reflect closing of the order in the work management system and completion of work			

10.2.10.5	Compare customer consumption levels with pre-defined limits and provide to designers for appropriate action (e.g. upgrade necessary).			
10.3	Service Address Information			
10.3.1	Provide the ability to classify the premise at the service level by NAISC code, sector code (e.g., car wash, restaurant, manufacturing, etc.)			
10.3.2	Maintain past and present history of the class of service regardless of meter type by use.			
10.3.3	Service Address Information			
10.3.3.1	Maintain multiple contact information (third party) related to the service address. The owner, manager, management company, etc. may be contacted to provide access to the premise, verification of tenant move in/out dates, handling of returned mail, etc. (Need to attach lawyer clearance letters).			
10.3.3.2	Capability to maintain user-defined premise information.			
10.3.3.3	Track areas of the premise where damage claims have been filed.			
10.3.3.4	Track Living / Service Unit Equivalent at the premise for use in cost of service studies (e.g. number of rooms, number of connections, square footage of the facility etc.)			
10.3.3.5	Track multiple heating sources at a single premise.			
10.3.3.6	View transformer location that feeds this service address			
10.3.3.7	View critical alerts at address level based on current account holder information or address based information (i.e. life support, critical service, etc)			
10.3.3.8	Display next scheduled reading date			
10.3.3.9	Display is keys on file for address			
10.3.4	Service Address History			

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10.3.4.1	On-line historical review of meters/equipment located at a premise for a specific period of time.			
10.3.4.2	On-line view of all previous and present accounts at a premise.			
10.3.4.3	Identification and tracking of all power equipment, appliances, products, etc. located at the premise. (Space heaters, Hot Tubs, Pools, etc.)			
10.3.4.4	Maintain seasonal usage history (monthly and peak).			
10.3.4.5	Maintain consumption and dollars for "3" number of years history (parameter driven). Ability to sort by service and combined services.			
10.3.4.6	Provide estimated and/or projected annual and average consumption.			
10.3.4.7	Provide the capability of approximating monthly, bi-monthly and quarterly utility costs for a premise. (based on history).			
10.4	Land Based Interface			
10.4.1	Integration with the GIS system to identify status of the premise with notification of when it becomes available for customer move in (e.g. Electrical Permit Approval).			
10.4.2	Provide the ability to "hold" or prevent initiation of service at an address until it is released by the party placing the hold or override and release.			
10.4.3	Enabled to allow GIS access methods and integration			
10.4.4	Provide interface to Work Management System to receive Occupancy Permit			
10.4.5	Provides access to other land based systems including a street index . (			
10.4.6	Update service address information for entire selected geographical area as specified, for example a change in street name, or postal code.			

10.4.7	System has the ability to interface to outage management system for review of outages at individual location.			
10.4.8	Identify if electric service is overhead or underground.			
10.5	Service Points			
10.5.1	Associate multiple service points with a service address.			
10.5.2	Associate non-metered, as well as, metered service points at a service address.			
10.5.3	Accommodate multiple meters for each service point at each address.			
10.5.4	Accommodate multiple non-metered service points at each address.			
10.5.5	Accommodate master meters at a service address.			
10.5.6	Accommodate service address class of service at the service point.			
10.5.7	View the past and present class of service of the premise for the service point.			
10.5.8	Accommodate rates at the service point.			
10.5.9	Accommodate service order work areas for the service point.			
10.5.10	Initiate an order for a specific service / service point without affecting the other services received. For instance, disconnect the electric service but leave the water service on.			
10.5.11	Track consumption at a service point.			
10.5.12	Accommodate routes by service point.			
10.5.13	Display service status (on, off, disconnected, load limited)			

End of Section

Table 10.2.12. Service Order Management

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11.0 SERVICE ORDER MANAGEMENT				
Item	Function / Feature	Vendor Score	Comments	Work Effort
11.1	Order Initiation			
11.1.1	Service Orders			
	An on-line initiation process to turn-on, transfer, turn-off or in any way modify service. Include the following:			
11.1.1.1	> Regular Turn-on / Turn-off			
11.1.1.2	> Transfer Turn-on / Turn-off			
11.1.1.3	> Seasonal Turn-on / Turn-off			
11.1.1.4	> Temporary Turn-on / Turn-off			
11.1.1.5	> Install (Set) Meter and Turn-on			
11.1.1.6	> Remove Meter and Turn-off			
11.1.1.7	> Marketer Switch Order			
11.1.1.8	> Turn-off for Non-Pay			
11.1.1.9	> Read and Leave On (special reads)			
11.1.1.10	> Stopped Meter			
11.1.1.11	> All other orders (User defined)			
11.1.1.12	> Key number			
11.1.1.13	Receive requests from meter read devices and generate an order.			
11.1.1.14	The ability to load re-reads and final reads in the handheld			
11.1.1.15	Ability to display alerts on service orders (online and printed) advising user to critical conditions (life support, dangers, etc).			
11.1.1.16	Ability to create service orders based on any type of work required to be completed--not strictly meter related. These can include no power, leak at meter, dirty water, etc).			
11.1.1.17	Ability to create service orders for non service address locations. These include infrastructure type orders for poles hit, water main breaks etc. These orders should not be tied to the customer premise as they are related to the system infrastructure.			

11.1.1.18	Ability to assign service orders to individuals or work groups and mass print.			
11.1.1.19	Ability to create service order types for various activities based upon business requirements. Service orders should be rule driven and can easily accommodate changes.			
11.1.1.20	Service order activities to be table driven allowing the user a selected number of activities/actions from pick list.			
11.1.1.21	Ability to complete service orders through mass updates. (i.e. all having the same activity or action)			
11.1.1.22	Based on service order type and/or status, the ability to delay billing of the account until resolved. This would alleviate some adjustments when a meter has been exchanged over the billing cycle. (user defined rules)			
11.1.1.23	Ability to notify users/departments when orders remain outstanding for X days			
11.1.1.24	Printed orders can include bar codes			
11.1.1.25	Display on printed service orders if keys are required by field personnel.			
11.1.1.26	Print a key report when mass printing of service orders--this report will list the service order number and corresponding key information (key ring, location, combination, etc)			
11.1.1.27	Automated service orders - download to caps & upload to CIS - with employee tracking			
11.1.2	Field Order Investigations			
	An on-line initiation process for field order investigations. Include the following:			
11.1.2.1	> Reread Meter			
11.1.2.2	> Diversion Investigation			
11.1.2.3	> Other Investigation (User Defined)			
11.1.2.4	> High/low Bill Investigation			

11.1.3 Meter Orders			
	An on-line order initiation process to set, remove or exchange a meter. Include the following:		
11.1.3.1	> Set Meter		
11.1.3.2	> Exchange Meter Non-Routine		
11.1.3.3	> Exchange Meter Routine (Periodic Change out)		
11.1.3.4	> Exchange Demand to Non-Demand Meter		
11.1.3.5	> Exchange Non-Demand to Demand Meter		
11.1.3.6	> Exchange Meter for Meter of Different Size		
11.1.3.7	> Dial Exchange (Dials)		
11.1.3.8	> Remove Meter		
11.1.3.9	> Rate change meter		
11.1.3.10	> Servicing a meter (Battery change)		
11.1.4 Equipment Orders			
	An on-line order initiation process to deliver, exchange or remove equipment. Include the following:		
11.1.4.1	> Deliver Equipment		
11.1.4.2	> Repair Equipment		
11.1.4.3	> Exchange Equipment		
11.1.4.4	> Remove Equipment		
11.1.4.5	> Equipment Investigation		
11.1.5 Collection Orders			
	An on-line order initiation process for collection related orders. Include the following:		
11.1.5.1	> Using Service Not Signed		
11.1.5.2	> Non-Pay Turn-off		
11.1.5.3	> Collection on a Bad Check or Debt		
11.1.5.4	> Non-Pay Re-connection		
11.1.5.5	> Electric Hazard Not Repaired		
11.1.5.6	> Meter Access Denied		
11.1.5.7	> Collection of Security Deposit		
11.1.6 Field Orders			
11.1.6.1	Accommodate work initiated and/or completed in the field.		
11.1.7 Emergency Orders			

11.1.7.1	Accommodated the initiation and completion of emergency work, initiated with minimal information, or entered into the system after the fact.			
11.1.8	Multiple Services			
11.1.8.1	A single order will address a single service only.			
11.1.8.2	Minimal screens are required to initiate the order.			
11.1.9	Controls			
11.1.9.1	Verify the customer and the premise exists within the system prior to allowing the order to post to the pending file.			
11.1.9.2	Verify the pending service order file prior to initiating an order. The system will not let two connect orders be placed for the same premise for the same customer for the same service for the same meter.			
11.1.9.3	The initiation of turn-on orders (transfers, regular connect, etc.) will force the previous customer off the premise and generate a final bill for the customer. The system must easily allow for correction to a customer account's final bill date, as well as a new customer account's start date.			
11.1.9.4	A turn-on/turn-off/transfer made in error can be reversed on-line.			
11.1.9.5	Notify the Key Account executive or CSR when a planned outage will affect the account or group of accounts. (Public Health, etc.)			
11.1.9.6	Identification and prioritization of accounts which should be reconnected first based upon special conditions after a power outage. (Critical Customer List)			
11.2	Pending Orders			
11.2.1	Pending Order Access			

11.2.1.1	Unique identification of the order by a system generated order number.			
	On-line inquiry and browsing of pending orders. Access will include:			
11.2.1.2	> Customer Name			
11.2.1.3	> Customer Account Number			
11.2.1.4	> Premise Street Address			
11.2.1.5	> Premise/Location Number			
11.2.1.6	> Order Number			
11.2.1.7	> Schedule Date/Date Completed			
11.2.1.8	> Order Status			
11.2.1.9	> Order Type			
11.2.1.10	> Meter Number			
11.2.1.11	> Who completed the order			
11.2.2	Order Status			
	Provide order status. Status types will include:			
11.2.2.1	> Scheduled			
11.2.2.2	> Onsite			
11.2.2.3	> Enroute			
11.2.2.4	> Dispatched			
11.2.2.5	> Completed			
11.2.2.6	> Unattempted with no date			
11.2.2.7	> Tagged (follow-up, attempted but not worked)			
11.2.2.8	> Held			
11.2.2.9	> Released			
11.2.2.10	> Cancelled			
11.2.2.11	> Condemned or Unsafe Condition (Red tagged)			
11.2.2.12	> Pending			
11.2.2.13	> Contractor notified			
11.2.2.14	> User defined			
11.2.3	Pending Order Scheduling			
11.2.3.1	On-line viewing of the existing workload and the next available time an order can be scheduled.			
11.2.3.2	Provide the customer with a time slot of when service will be provided, e.g. between 10:00 and 11:00 am.			

11.2.3.3	Provide the ability for a service order that has been held pending payment of a deposit, the system will release the service order when payment is made.			
11.2.3.4	Input partial orders into the pending order file without specifying all required order information. Allow the customer to call back with additional information at a later date. Schedule the order upon receipt of info.			
11.2.3.5	Provide a method for identifying service orders which require additional information with a user generated deletion (with a max period "x" time allowed) and report date.			
11.2.4	Pending Order Modification			
11.2.4.1	On-line access, viewing and modification of a pending order.			
11.2.4.2	On-line access to cancel a pending order. The system will retain the cancelled order with the reason it was cancelled and who cancelled it.			
11.2.4.3	Cancellation of the pending disconnect order will automatically cancel the transfer connect, the landlord connect or other associated orders, with override capabilities.			
11.2.4.4	Identify cancelled orders through a cancellation notice for those orders which have already been issued.			
11.2.4.5	Orders changed to same day or emergency orders will automatically be queued for scheduling / issuing at the appropriate service centre.			
11.2.4.6	Uncompleted orders are carried over to the next day.			
11.2.4.7	Collection orders will be cancelled if payments and/or payment arrangements are made.			
11.3	Mobile Computing Interface			

11.3.1	Interface with a Field Service Management system or other Mobile system for order scheduling and dispatching (MDSI)			
11.4	Work Management Interface			
11.4.1	Interface with a Work Management System for order planning, design, approval, work, and completion			
11.5	Outage Management Interface			
11.5.1	Interface with outage management system			
11.5.2	Interface with the IVR system			
11.5.3	Interface with the GIS system			
11.6	Service Order Distribution			
11.6.1	Order Routing			
11.6.1.1	Orders are automatically routed to the appropriate service WorkStation/dispatch/printer/workstation. User defined flexible routing and sequencing of orders. Examples include: request date, order type, order priority, premise, service area and work area.			
11.6.1.2	Reroute an order on-line from one service dispatch/dispatch workstation to another.			
11.6.1.3	Reroute an order to an automated close status based on defined parameters for a Move In/Out service order.			
11.6.2	Order Scheduling			
11.6.2.1	Support automated work load balancing for the dispatch function.			
11.6.2.2	Schedule orders by service area based upon order priority, date requested, service department staffing level, and current backlog .			
11.6.3	Order Grouping			
11.6.3.1	The system will group pending orders for efficient service purposes (turn-on/turn-off, address).			
11.6.4	Order Viewing / Scheduling / Issuing			

11.6.4.1	On-line review of all pending orders, all emergency orders, all tagged orders for a specific work date, and/or a specific service order area.			
11.6.4.2	A same day order (non-emergency) will be issued immediately at the service location.			
11.6.4.3	Identification of an order as being a repeat (2nd, 3rd request) order requiring immediate attention. (Duplicate)			
11.6.4.4	Provides the capability of issuing service orders in a logical ordering of cycle, route, and sequence of meter.			
11.6.4.5	Provides the capability of viewing / reissuing specific orders, or a group of orders.			
11.6.4.6	Orders can be printed on various paper stocks and sizes.			
11.6.5	Order Information			
11.6.5.1	Place relevant customer and premise information on the order. Flexibility in defining the information to be printed on the order.			
11.6.5.2	Display/print on service order special handling situations relevant to the premise/customer when taking the order, e.g. requires special handling by electric dept; dangerous customer; service on hold by health dept, life support, overhead wire, etc.			
11.6.5.3	Display/print the multiple contact info (third party) related to the service address. The owner, manager, management company, etc. may be contacted for access to the premise, to verify tenant move in/out dates, handling of returned mail.			
11.6.5.4	An emergency order will be highly visible as an emergency order requiring immediate attention.			
11.6.5.5	On-line comments can be put on the service order. (Pick menu)			

11.6.5.6	Customization of the service order format is user definable.			
11.6.5.7	Process Move Out and Move In customer account requests correctly			
11.6.5.8	Easily allow for correction or modification to the start and end dates for the customer accounts, including after the Move In / Move Out has been completed and billed			
11.6.5.9	Move Out and Move In processes should be automated via Service Orders that obtain field reads and/or shut off and turn on meters. Allow for force out of existing customers when starting a new customer at a property.			
11.7	Order Completion			
11.7.1	Order Completion			
11.7.1.1	The pending orders can be accessed and completed on-line by order number, order type, schedule dates, order status, etc.			
11.7.1.2	Provide the ability to work/complete service orders regardless of where the customer/location is in the billing cycle.			
11.7.1.3	Provide the ability to enter and complete service orders in one step for emergency orders and field initiated orders.			
11.7.1.4	Allow for input of the actual date service order is worked/completed including weekend and holidays.			
11.7.1.5	Order information is captured at the time the order is completed and retained with the premise, the customer, and/or the account.			
11.7.1.6	Any type of transfer connect will transfer applicable portions of the customer record such as credit profile to the new connected account			

11.7.1.7	The results of a service call can be entered into the system during completion with actual work performed overriding the original order if there is a difference.			
11.7.1.8	Completion of the order will change the status of the pending order and identify it as a completed historical order (on-line)			
11.7.1.9	Highlight and report on order activities by order type or other defined field.			
11.7.1.10	Supports performance statistics and reporting: average response time to service calls, average time to complete various types of service calls, service calls completed by each service technician.			
11.7.2	Order Tagging			
11.7.2.1	Identification of tagged orders. Ability to identify a fee for service if the service person showed up and the customer was not available.			
11.7.2.2	Rescheduling of orders which were attempted and tagged.			
11.7.3	Order Rescheduling			
11.7.3.1	Identification and notification of the customer when an order is unable to be worked or if the crew is running behind.			
11.7.3.2	Identification of orders that have not been worked on the scheduled date.			
11.7.3.3	Rescheduling of orders which have not been worked on the scheduled date. (Follow-up)			
11.7.4	Service Charges			
11.7.4.1	Capture additional/unplanned service charges that are determined in the field, for example, tampering, collection fees, etc.			
11.7.5	Meter Tampering			

11.7.5.1	Identify customers suspected of tampering, the tampering information is captured and updated to the customer, premise, customer account, and/or meter record. (Schedule an automatic revisit in the future to check meter status).			
11.7.6	Meter Test Results			
11.7.6.1	Record meter and meter component test results completed in the field and feed results to the meter inventory.			
11.7.7	New Service Routes			
11.7.7.1	Identification of all new services which do not have a route assigned.			
11.8	Order History			
11.8.1	On-line historical review of completed orders for the customer account or service address (newest to oldest).			
11.8.2	Maintains a record of all trouble calls and complaints received from a customer at a specific premise.			
11.8.3	A image of the service order will always be kept for on-line viewing			
11.8.4	Automatic Archive to file (image of orders after completion).			
11.8.5	Ability to generate reports based on variable parameters to determine open and closed service orders status, and productivity, and outstanding opened orders.			
11.8.6	PBR Tracking of Appointments kept / not kept			

End of Section

Table 10.2.13. System Mechanics

12.0 SYSTEM MECHANICS				
Item	Function / Feature	Vendor Score	Comments	Work Effort
12.1	Multi Company			

12.1.1	System must provide multi company capability			
12.1.2	System must address tax implications of transferring accounts to other jurisdictions			
12.1.3	System must provide ability for customer to have accounts in multiple jurisdictions			
12.1.4	System provides for multiple time zones			
12.1.5	System accommodates multiple currencies			
12.2	System Navigation			
12.2.1	System provides windows-like point and click navigation.			
12.2.2	System is web-enabled			
12.2.3	System has an easy to use and easy to maintain calendar allowing adjustment for holidays, weekends, appointments, etc.			
12.2.4	System can identify next scheduled meter read			
12.2.5	Provide for user configurable screens / windows			
12.2.6	Provide for standardized screens / windows			
12.2.7	Provide for direct screen/window access from anywhere within the system (drop down, fastpath)			
12.2.9	Provide a method for the user to tailor system access to meet their specific requirements, such as menus items and hot keys.			
12.2.10	System provides navigation using hot keys instead of the mouse.			
12.2.11	Provide the capability of specifying new customer/ premise information on any screen without having to return to a main menu or search screen.			
12.2.12	Maintains key header information from one screen to the next. Customer name, service address, start date, etc.			

12.2.13	Valid values should be available in a drop down box or popup window.			
12.2.14	Values can be inputted directly without the use of a drop down box. Can type first few letters and value will display or placed in the drop down list.			
12.2.15	Provides the ability to have user defined fields at the major data entities such as customer, premise, account, etc			
12.2.16	Provide the ability to display pertinent alerts on various screens based on user defined criteria. Alerts to include critical collection activity, life support, multi-unit services, outstanding service orders, etc			
12.3	System Control			
12.3.1	The system uses a "rule-based" architecture allowing a secured user to set up and maintain the software without requiring programmer intervention.			
12.3.2	Allows for the monitoring of system uptime, response time, and batch window in order to keep within acceptable levels.			
12.3.3	Daily balancing to include cash, returned items, accounts receivable, deposits, and billing.			
12.3.4	Capability for diagnostic reporting if out of balance.			
12.3.5	Support real time on-line update as the primary processing mode.			
12.3.6	Provide ability to selectively archive system data based on user-defined number of years or other user-defined criteria. The archived data can be accessed via another medium such as tape or additional disc space. Provide secondary process to purge archived data.			

12.3.7	Can archive data so that it can be easily retrieved. This should include the user ability to retrieve data through account details such as address and account number without technical assistance.			
12.3.8	Search by (sounds like) for address and customer			
12.3.9	Search by wild card			
12.3.10	Provides the ability to make necessary adjustments and close revenue months and provide a secure auditable financial record.			
12.3.11	Capability for diagnostic reporting if out of balance when closing revenue months.			
12.3.12	Conduct mass changes across accounts, customer records, or premises. For instance Zip/Postal code changes.			
12.3.13	Accommodates interfacing with street sweeper for zip codes.			
12.3.14	Allow users to maintain key system parameters on-line without the need for IS intervention to change the values. This includes items such as: rate tables, edit parameters, security access, etc. An audit log is maintained. (Step security access)			
12.3.15	On-line submission of batch jobs to be run in a real time or a batch mode. Ability to utilize a scheduler for automated submission.			
12.3.16	Able to schedule jobs by dependencies so that one job starts after another completes			
12.3.17	System provides detailed error messages. (Certain errors will be alerted to system administrator with priority assigned)			

12.3.18	Work management queues should be customizable based on business needs including assigning to individuals or departments.			
12.4	On-line Help			
12.4.1	On-line help is available and can be printed if necessary.			
12.4.2	On-line help is available at the system, function, screen, and field level. Plus user help is maintainable by the user.			
12.4.3	On-line help will be updated with each new version release.			
12.4.4	On-line help provides an index and search capability			
12.4.5	On-line help is context sensitive. System will recognize cursor position for a fast path to the help text.			
12.4.6	The system user manual is provided on-line. (Will also require a hard copy)			
12.5	Computer Based Training			
12.5.1	Provide computer based training programs so users can train independent of classroom training.			
12.5.2	Ability to customize computer based training to meet specific company scenarios			
12.6	Automated Work Queue			
12.6.1	Provide for the electronic management, routing by office or workgroup, and reporting of work generated by the system such as nightly batch or update.			
12.6.2	Provide for the electronic management, routing, and reporting of work generated and completed by individuals such as adjustments made, service work requested.			
12.6.3	A work queue can be managed or owned by an individual, variable work group, department, or location.			

12.6.4	A series of queue's can be defined based upon system exception conditions requiring follow-up, items requiring review, and approval, or to do items.			
12.6.5	The flow of work can be defined from initiation of a work queue item through various in process, review, and approval activities. The work queue will follow a logical progression.			
12.6.6	Work queue items can be modified and deleted on-line.			
12.6.7	Work queue items can be reassigned to another individual, work group, department or location on-line.			
12.6.8	An entire work queue or a subset may be viewed and printed.			
12.6.9	Appropriate controls will be placed on key queues to notify users of the need to work the queue. As new items are routed to the queue, users will automatically be alerted.			
12.6.10	Provide for work queue usage and performance statistics.			
12.6.11	Provide for supervisory work queue aged alerts.			
12.6.12	Supervisor can view daily work queues. Can also assign work to queues.			
12.7	Notes/Remarks			
12.7.1	Provide for an unlimited amount of notes/remarks.			
12.7.2	Provide for free form notes/remarks.			
12.7.3	Provide for categorization of notes/remarks.			
12.7.4	Provide options for sorting and displaying notes/remarks.			
12.7.5	Provide an automatic delete or purge date on a note/remark.			
12.7.6	Provide for the identification of critical notes/remarks.			
12.7.7	Provide author information. User ID, date/time entered, etc.			

12.7.8	Provide pre-defined notes/remarks or comments.			
12.7.9	Provide for mass update of same text message on a note across multiple accounts.			
12.8	System Security			
12.8.1	System security is capable of preventing unauthorized users from logging into the database.			
12.8.2	System constrains authorized users to the data they are approved to access.			
12.8.3	Specify user access and security by screen and type of action such as update versus inquiry.			
12.8.4	Provide for field level security.			
12.8.5	The ability to track the use of the system by authorized users.			
12.8.6	The ability to report attempts by unauthorized users to use the system.			
12.8.7	The ability to suspend after "x" attempts to access the system with an incorrect password.			
12.8.8	The ability to turn on tracking against any user ID and generate daily reports of system updates.			
12.8.9	The ability to run reports on all user id's to determine all access capabilities.			
12.8.10	Security Access set by roles and specific levels			
12.8.11	User's capable of being assigned roles and individual security restrictions. Plus ability to flag accounts belonging to employees for special reporting.			
12.9	Approvals			

12.9.1	Provides adequate levels of management review and approval throughout the system, this may include an automatic queuing or routing of transactions pending management approval.			
12.9.2	Provides the ability to establish approval based on user defined thresholds.			
12.10	Auditing			
12.10.1	Provides accurate transaction registers and audit trails for system transactions.			
12.10.2	Provides internal program controls, edit checks, and audit trails for all transactions that impact the amount and/or timing of customer billing and collection activity.			
12.10.3	Has current, clear and understandable documentation that facilitates an efficient and effective audit of the CIS solution's functions, internal program controls, edit checks, and audit trails by the Utility's outside auditors and which results in their unqualified opinion that the controls are adequate to insure that financial transactions are recorded and posted consistently and accurately in accordance with the utilities' rates and policies			
12.10.4	Automatically creates a complete detailed audit trail including information such as date, time, and User ID.			
12.10.5	User can review transaction history on-line.			
12.10.6	User can review transaction history in a report.			
12.10.7	Transactions can be selected by any combination of date range, transaction type, User ID, premise, customer, etc.			
12.11	Reports			
12.11.1	The system contains a full array of standard reports.			

12.11.2	Reports contain multiple select and sort parameters to support various standard utility reporting requirements.			
12.11.3	Standard and utility specific reports can be scheduled to print daily and nightly using standard system functionality.			
12.11.4	System reports can be generated and viewed on-screen before printing.			
12.11.5	System provides integration to a data mart or data warehouse			
12.11.6	Provide the ability to create and define an unlimited number of user defined reports utilizing query, third party report writing tools (e.g. Crystal Reports).			
12.11.7	Letters and Reports for mailing can be routed to third party printing firms without user intervention			
12.11.8	Captures and reports the number of customer accounts that did and did not pass through each billing cycle process, from scheduled meter read through final bill print. This enables the Utility to determine whether all customers in each cycle had their meter read, all meter readings were uploaded, bills were calculated and the bills were either printed or made available for printing.			
12.11.9	Provides a series of standard daily, weekly, and end-of-period accounting reports, by fund and transaction type, that permit (a) daily system balancing against such external controls as deposit slips or customer bills, (b) regular postings to and reconciliation of the GL control totals with the Utility's general ledger, and (c) system security and access monitoring.			

12.11.10	Provides a series of standard management detail and summary reports, by fund, which show status of customer account balances and results of collection efforts for any period of time specified. Such reports include receivable aging lists as well as detailed and summary reports on billing transactions, adjustments, delinquent customer accounts that are in a collection process program, assigned to a collection agency, have declared bankruptcy, or are considered uncollectible			
12.12	System Recovery			
12.12.1	Provide transaction logging or journalizing at the data base level			
12.12.2	Ability to recover the system from the transaction log			
12.13	Product Technology			
12.13.1	The product is available within a proven development environment which adequately supports all phases of the system life cycle and utilizes designer/programmer workbenches at a minimum.			
12.13.2	The product currently utilizes a windowed / web based environment offering a full industry compliant GUI desktop environment.			
12.13.3	The vendor has available a product which operates in a client server cooperative processing environment.			
12.13.4	The client interface will link to desktop productivity tools e.g. word processing, spreadsheet and data base.			
12.13.5	Provides easy design of user-defined queries and reports that can be exported to standard desktop tools such as MS Excel or MS SQL for additional analysis.			

12.13.6	The product provides for tools to easily export data to a data warehouse.			
12.13.7	The product provides easy access and reporting of information through use of powerful report writing and query tools.			
12.13.8	The product provides flexible features within a user defined environment, allowing the authorized user administrator to easily configure the base application.			
12.13.9	The application must support TCP/IP.			
12.13.10	The application must provide for data transparency. (Allow other system to read each other)			
12.13.11	The application must provide for data security.			
12.13.12	Generally, the solution will promote a central repository for purposes of data security, control, backup and recovery.			
12.13.13	A relational data base management system is required.			
12.13.14	The product design and modularity allow it to be ported to smaller and /or larger platforms without the need for excessive redesign work (plug and play).			
12.13.15	The solution presents a platform which provides connectivity, scalability, and portability within and across vendor products (must be platform independent).			
12.13.16	The solution will position the Utility to easily take advantage of evolving technologies such as imaging, work group computing, video conferencing, etc.			
12.13.17	Overall the product and its life cycle tools provide for a simplified and timely modification environment.			

12.13.18	The Utility is looking for the vendor to support the product and grow the product to maturing platforms.			
12.13.19	The product was developed on the platform proposed by the Vendor and optimizes the proposed platform's data base(s) and operating system.			
12.13.20	The product database allows access by an SQL-based language.			
12.13.21	The product has been designed around a core package which provides standard functionality and data structure for the primary utility services. The core package provides user defined exits, user defined fields, user defined screens, user defined reports,			
12.13.22	The primary focus of the product is on-line real time entry and update of information.			
12.13.23	The product allows for on-line work routing and approval, on-line bill calculation and generation, etc.			
12.13.24	On-line response time for inquiry and basic updates is within an acceptable range averaging no more than sub second during peak usage.			
12.13.25	Any batch window executes within an acceptable maximum period of 2 hours.			
12.13.26	The product will be available and support 24 hour by 7 day a week business operations.			
12.13.27	The product provides security at the system, business function, and screen level. Restriction is by user, or defined user group, for access to customer account and service address information and related processing.			
12.13.28	The product provides security at the field level.			

12.13.29	The product has been developed using a proven methodology employing structured design and coding techniques. In addition the source code is well documented both inline and external documentation.			
12.13.30	Please note the programming language used.			
12.13.31	The product source code is available to the Utility.			
12.13.32	The product source code is available for placing into escrow to be available to the Utility in the event that the vendor is acquired by another company.			
12.13.33	The product offers a method to easily archive information to history and retrieve that information. A method is provided to purge data from the archived media.			
12.13.34	The product offers on-line inquiry during the batch processing window.			
12.13.35	The product offers on-line update during the batch processing window.			
12.13.36	The product provides full restart and recovery features for all batch transactions			
12.13.37	The solution provides full recovery features for all on-line transactions.			
12.13.38	System backup and restore can be accomplished within a maximum of 1 hours.			
12.13.39	The solution provides a comprehensive computing site disaster recovery or business recovery approach.			
12.13.40	A product data model is available and has been provided for review of major data entities and relationships.			
12.13.41	Automated batch run-to-run control processing. (Batch scheduling)			
12.13.42	The solution provides an integrated batch scheduler.			

12.13.43	Provide automatic logging of system changes by user for on-line review.			
12.13.44	Each record contains a date/time stamp reflecting last add/change.			
12.13.45	The Utility has permission to freely copy all system and technical documentation, once the contract with the vendor has been signed, for internal use.			
12.13.46	The solution provides the ability to maintain distinct testing vs. production environments.			
12.13.47	The solution provides a tool to generate a test region for a subset of accounts, bringing over configuration and history from the production or other region.			
12.13.48	The solution will work within the Utility's existing network environment, taking full advantage of existing topologies (i.e. optimizes the bandwidth).			
12.13.49	The solution and required hardware will be sized to accommodate the utility's customer base and number of users.			
12.13.50	The product provides a full suite of utility jobs required to execute various systems maintenance functions including:			
12.13.51	· Version control of source code			
12.13.52	· Disk management			
12.13.53	· Tape management			
12.13.54	· Multiple on-line sessions			
12.13.55	· Storage archival and retrieval			
12.13.56	· Sort utility			
12.13.57	· Job scheduling utility			
12.13.58	· Performance monitoring (application and system)			
12.13.59	· Ability to monitor executing jobs			
12.13.60	· Debugging tools			
12.13.61	· Transaction monitors			
12.13.62	· Programming tools			

12.13.63	Any batch process can be re-started without data corruption.			
12.13.64	Batch notifications are automatically generated when a process fails or exceeds pre-determined time periods			
12.14	Product Installation			
12.14.1	The vendor offers professionals experienced in the development tools and environment required to implement the product within the proposed platform.			
12.14.2	The vendor has an extensive experience and knowledge of the utility industry and its related services, products, and programs.			
12.14.3	The vendor has an extensive number of experienced professionals upon which to draw in support of this implementation effort.			
12.14.4	The vendor has the financial and human resources to support a project of this size within the timeframe specified.			
12.14.5	The vendor is attempting to minimize the overall product cost through the use of development technologies, tools, outsourcing strategies, etc.			
12.14.6	The vendor is willing to act as primary contractor with complete responsibility for installation activities and ultimate success of the project.			
12.14.7	The vendor will provide project management services.			
12.14.8	The vendor will conduct detailed design activities resulting in the development of detailed specifications for each identified product modification (as necessary).			
12.14.9	The vendor is responsible for installation of the base product.			

12.14.10	The vendor will work with the Purchaser in installation of all proposed server hardware and system software.			
12.14.11	The vendor is responsible for connectivity with existing environment.			
12.14.12	The vendor is responsible for the installation of a relational data base management system and associated query and report writing software.			
12.14.13	The vendor is responsible for product customization and testing for modifications.			
12.14.14	The vendor is responsible for the development of data conversion programs and services from the existing system to the new customer system.			
12.14.15	The vendor is responsible for the product modification and the development of all required interfaces from the product perspective.			
12.14.16	The vendor is responsible for the development of Utility specific reports.			
12.14.17	The vendor is responsible for product training and documentation (application & technical). Train the trainer approach for user training.			
12.14.18	The vendor is responsible for thoroughly testing the product as customized for the Utility.			
12.14.19	The product must consist of complete, up-to-date, easy to use documentation related to product operation, technical support, business operations, etc.			
12.14.20	Vendor must provide documentation that includes description of the capability of the system and each sub-component			

12.14.21	The product must consist of complete customizable training material (manual and automated) to provide for initial and ongoing training requirements.			
12.14.22	The vendor is responsible for all production conversion activities and cut-over to the new system.			
12.14.23	The vendor is responsible for post conversion activities for a defined period of time.			
12.14.24	The vendor is committed to a final system acceptance test period regarding measurement of system performance against agreed upon performance guidelines.			
12.14.25	The vendor is willing to commit to a fixed fee contract for the installation phase of the project.			
12.14.26	The vendor approach and recommended installation timeframe meets Utility business requirements.			
12.14.27	The upgrade process is well supported and takes a reasonable amount of effort. No consulting assistance is required in order to perform upgrades.			
12.15	Vendor Profile			
12.15.1	Vendor is a well established professional organization offering software products and services. The vendor will have been in business for a minimum of 5 years with a minimum of 100 employees working within the product development and support business.			
12.15.2	The vendor must be a financially healthy institution capable of conducting business during the short-term development effort and the long-term maintenance and support effort as measured by financial statements, D&B report, etc.			

12.15.3	The vendor has been primarily responsible for the successful installation of the recommended product within various client engagements. The proposed product has been recently installed with a minimum of more than 1 utility with a customer base of 250,000-500,000. Must also be a multi-service utility install.			
12.15.4	The client references pertaining to vendor product design, installation, and product support must reflect a record of excellent service and professionalism.			
12.15.5	This project is part of a comprehensive plan and general direction of the vendor to actively promote its product development platform(s) and pursue ongoing product development and enhancements.			
12.15.6	The proposed product is currently in production on a similar platform being proposed for the Utility.			
12.15.7	The vendor must not be involved in any major litigation which may potentially impact the vendors ability to support this installation project and ongoing maintenance and support.			
12.15.8	The vendor is offering a product which has been developed primarily for the utility environment and accommodates the Utility's services, products, and programs.			
12.15.9	This project will receive the full attention and support of the vendor. As a result the vendor will place key people onsite as required during the development, training and installation effort.			

12.15.10	A product warranty period exists at which point the Utility may elect to return the product or hold the vendor responsible for additional work within the original contract.			
12.16	Vendor Support			
12.16.1	The vendor offers an organization focused on the ongoing support and development of the customer product. This is typified by items such as product support lines, R&D departments, and specialized development groups.			
12.16.2	The vendor has a record of responsiveness to the needs of its installed customer base. Specifically, the vendor will respond within two hours to customer requests.			
12.16.3	The product is not constrained by a proprietary set of development or CASE tools which will restrict product modification.			
12.16.4	Product allows for modification through "exits" that allow custom modifications to continue to function through upgrades			
12.16.5	The Utility will receive priority service for product modifications and releases.			
12.16.6	The vendor will commit to and guarantee performance and responsive standards for program problem resolution and training.			
12.16.7	The vendor will identify ongoing product support charges and rates to be incurred by the Utility.			

12.16.8	The vendor offers an extensive, flexible, and competitively priced maintenance agreement. Maintenance of the product in conformance with Ontario EBT and regulatory requirements will be included in the maintenance agreement.			
12.16.9	The product is supported through a 24 hour a day product support line staffed by business and technical professionals.			
12.16.10	The vendor is providing a comprehensive business recovery plan and disaster recovery provisions.			
12.16.11	If the need arises the vendor will place individuals on-site within a defined period of time (same day or next business day).			
12.16.12	The vendor is planning on regular upgrades (enhancements and product fixes) to the product. The ongoing product maintenance fee will allow the Utility to utilize product upgrades without additional charges.			
12.16.13	The installed product base is represented through a user group. This group is tasked with the identification and prioritization of product upgrades.			

End of Section

Table 10.2.14. Usage Management

13.0 USAGE MANAGEMENT				
Item	Function / Feature	Vendor Score	Comments	Work Effort
13.1	Consumption Types			
13.1.1	Passage of Time			
13.1.1.1	Measure usage based upon the passage of time. For example product contracts and payment plans.			

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13.1.2	Measured Flow			
13.1.2.1	Measure usage based upon a measured flow. For example usage of electricity, flow of water, Gas			
13.1.2.2	Measure usage based upon a measured flow over a period of time. For example time of use or time of day.			
13.1.2.3	Record loss adjusted usage			
13.1.2.4	Record loss adjusted usage correctly when the loss factor changes in the middle of a usage period.			
13.2	Consumption View			
13.2.1	View consumption by service address or location			
13.2.2	View consumption by service and service point.			
13.2.3	View consumption by meter, equipment or product. (Electric TOU on-peak/Off-peak.)			
13.3	Route Features			
13.3.1	Route Structure			
13.3.1.1	Provide for routes, sequence numbers and stops.			
13.3.1.2	Supports route and sequence numbers to allow multiple meters/equipment single stop.			
13.3.1.3	Accommodate multiple routes per service address (each service point can have its own route)			
13.3.1.4	Accommodate routes for non-metered services separately from meter-reading routes (contract lighting). (These accounts should not be assigned a route)			
13.3.2	Routing			
13.3.2.1	Allow for the establishment of a new route			
13.3.2.2	Allow changes to the route, and/or sequence number without changing the account number.			
13.3.2.3	Allow for the deletion of a route.			

13.3.2.4	Automatic re-routing feature for re-arranging routes. This feature would allow for the addition of a new route, the removal of an existing route, and the ability to reorganize and/or combine existing routes in an on-line or batch mode as requested.			
13.3.2.5	Automatic renumbering feature for re-arranging stops on a route to allow for addition of premises.			
13.3.2.6	Automatic re-sequencing feature for renumbering sequences within a stop to allow for the addition of meters or equipment.			
	System updates and maintains the following information for each meter route:			
13.3.2.7	> User-defined route identifier			
13.3.2.8	> Meter Reader assigned to route			
13.3.2.9	> System generated next read date			
13.3.2.10	> Description of route			
13.3.2.11	> System generated last read date			
13.3.2.12	> System generated total number of meters in route			
13.3.2.13	> End time of reading route			
13.3.2.14	> Elapsed time between meter readings (number of days)			
13.3.2.15	> Start time of reading route			
13.3.2.16	> Mileage of route			
13.3.2.17	Automatic re-sequencing feature for renumbering sequences by the meter reader on the hand-held device.			
13.3.2.18	Support the scheduling of routes by taking into consideration: available person power, workload, and read window or interface with routing system.			
13.3.2.19	Provide assigning of move service orders to special meter routes. These are then downloaded into the hand-held reading equipment for the field readers.			
13.4	Reading Initiation			

13.4.1	Initiation of reads based upon cycle billing and associated reading schedules.			
13.4.2	Initiation of reads based upon specific events such as: high bill complaint, disconnection / connection of service, etc.			
13.4.3	Verify information is complete or the account is flagged for first time reads of new service meters.			
13.4.4	Automatically identify services which have not had an actual read within "X" months. Once identified, based on conditions initiate correspondence to customer requesting read. If still not read after determined time period, automatically assign high consumption amount to service (bump) to initiate response from customer. (i.e. electric consumption of 10,000 kwh)			
13.4.5	Meter reading Instructions based on service address (i.e. meter under step)			
13.4.6	Meter reading Instructions based on service account/account (i.e. leave card)			
13.4.7	Provide key report listing for all routes requiring keys for accessing meters. Field personnel to obtain the appropriate keys before leaving office.			
13.5	Reading Interface			
13.5.1	Hand-held Interface			
13.5.1.1	Download of information into the PC based handheld meter reading and route management system. (Itrons MVRS)			
13.5.1.2	Selective download of accounts into the handheld based upon reading type e.g. type of meter, time period, etc..			
13.5.1.3	Include the download of meter information for inactive accounts.			

13.5.1.4	Upload read information from the PC based meter reading system. Update premise information gathered by the meter reader.			
13.5.1.5	Input reads received from the customer (various sources) in the case of temporary service accounts, hard to reach meters, or rural accounts.			
13.5.1.6	Record visual checks by meter reader of special conditions.			
13.5.1.7	Validation override performed by meter reader at hand-held device is reported to the system.			
13.5.1.8	Provide controls to safeguard the upload and processing of the same readings more than once (duplicate reads).			
13.5.2	AMR Interface			
13.5.2.1	Interface with various telemetering devices or a telemetering system for polling and upload of meter read information.			
13.5.3	Other Consumption Interfaces			
13.5.3.1	Provide a standard interface to real-time consumption and pricing sources. For example the ability to accommodate "x" number of readings over "x" period of time. (i.e. MV90)			
13.5.3.2	Print route books for specific services which may not utilize automated devices.			
13.5.3.3	Input a batch tape or EDI of meter reads performed by another company .			
13.5.3.4	Read another company's meters and provide a batch tape or EDI to provide the readings.			
13.6	Consumption Validation			
13.6.1	Storage of all reads received regardless of their validity.			

	Readings will be validated prior to billing, an example of the type of validations performed are:			
13.6.2	> Number of Dials On A Read			
13.6.3	> Read Type (On/Off Peak)			
13.6.4	> Dial Turnover			
13.6.5	> Read Units (KW, KWH, KVA, RK, Units, 100 cubic ft.)			
13.6.6	The system will provide the following reasonableness checks (high and low, zero consumption for "x" months) against recorded usage:			
13.6.7	> Current Consumption to Last Months Low Consumption			
13.6.8	> Current Consumption to Year Ago's Low Consumption			
13.6.9	> Current Consumption to Last Month's High Consumption			
13.6.10	> Current Consumption to Year Ago's High Consumption			
13.6.11	> Current Consumption to the Special Parameters Established by Users			
13.6.12	> Anticipated consumption on new accounts			
13.6.13	> History for the address if complete history is not available for the customer (customer vs. location)			
13.6.14	> Anticipated peaks, valleys, and annual consumption's for premises based on size, general area, equipment, heat factors, etc.			
13.6.15	The system will estimate based on usage at a previous premise for an account if the current premise does not have enough history to prepare an estimate			
13.7	Measurement Features			
13.7.1	Directly input a corrected usage and retain both the corrected reading and the original reading.			

13.7.2	Provide the conversion of reading units to billing units including the ability to have more than one reading unit per billing unit.			
13.7.3	Allow number of decimal places of precision of meter reading to be flexible and vary per unit of measure.			
13.7.4	Accommodate the input of actual date read versus scheduled read date.			
13.7.5	Viewing of meters with zero consumption based on user defined variables for "X" number of months.			
13.7.6	Viewing of meters with unexpected consumption based on user defined variables for example status.			
13.7.7	Support a minimum of 10 digits for storage and display of the read.			
13.8	Processing			
13.8.1	Ability to automatically generate a work queue with the option to send service orders and generate customer letters, based on information gathered by the meter reader.			
13.8.2	Update meter reading conditions			
13.8.3	Update meter reading locations and instructions			
13.9	Meter Reading Performance			
13.9.1	Verify scheduled accounts were read			
13.9.2	Monitor route detail time study			
13.9.3	Monitor error conditions and accuracy of readings			
13.10	Unauthorized Usage			
13.10.1	Provide a mechanism for meter readers and service personnel to report the detection of unauthorized usage.			
13.10.2	Provide automatic notification to the meter readers and service personnel and flag the responsible party regarding a theft of service condition.			

13.10.3	Viewing of accounts with unauthorized usage/off-meter consumption.			
13.11	Reports			
13.11.1	Provide an unbilled usage report by account for month end financial reporting, showing estimated unbilled dollars and energy units by rate by charge type.			
End of Section				

Table 10.2.15. Customer Choice EBT Requirements

14.0 Customer Choice - EBT Requirements				
Item	Function / Feature	Vendor Score	Comments	Work Effort
14.1	General Requirements			
14.1.1	EBT transactions are tightly integrated with CIS processes. CIS processes automatically create required EBT's without user intervention. Incoming EBT's automatically trigger CIS functions where possible without user intervention.			
14.1.2	There is a user friendly work environment to inquire on, review, reject and accept EBT's where required.			
14.1.3	Automatically generate and log all required HTTP status codes.			
14.1.4	Automatically identify and log all transactions with invalid digital signatures.			
14.1.5	Ability to encrypt and decrypt XML documents as per Ontario Energy Board (OEB) guidelines.			
14.1.6	Automatically generate well-formed and valid XML documents based on published schema.			

14.1.7	Automatically transmit and process well-formed and valid XML documents.			
14.1.8	Ability to split all XML documents into individual XML transactions assuming size of document will not exceed 500 MB			
14.1.9	Ability to automatically assemble XML transactions into XML documents			
14.1.10	Ability to automatically monitor, identify and report any delayed responses to XML transactions			
14.1.11	Track all transaction errors and provide an organized, online, user friendly mechanism for resolution that highlights individual errors and guides the user to the same.			
14.1.12	Demonstrate the ability to process all requests from retailers including:			
14.1.13	> Enrol			
14.1.14	> Drop			
14.1.15	> Historical Usage			
14.1.16	> Historical Payment			
14.1.17	> Change Consumer Information			
14.1.18	> Change Consumer Location			
14.1.19	> Change Billing Option			
14.1.20	> Meter Change			
14.1.21	Automatically log (assign) all EBT related exceptions to appropriate worklist for follow on action.			
14.1.22	Demonstrate that all subsequent and relevant transactions can be linked to the original transactions in accordance with EBT Standards.			
14.1.23	The System supports an interface to a complex billing engine such as Lodestar for calculating and delivering NSLS to retailers daily.			
14.1.24	The system supports all market participant charges and settlement costs by retailer			

14.1.25	Issue Settlement Invoice Total and Settlement Invoice Detail transactions daily as per OEB requirements (EBT Standards v2.1a; demonstrate knowledge and plans to support v2.2 requirements)			
14.1.2	Switches Between Energy Providers			
14.1.23.1	Support a switch from Standard Supply Service (SSS) to a retailer, retailer to retailer, or retailer to SSS on a scheduled read date			
14.1.23.2	Calculate accurate effective date of enrolment and flow date, taking into account meter reading schedule and any market driven blackout windows			
14.1.23.3	Communicate flow date to retailer as part of the Enrol Accept transaction			
14.1.23.4	Demonstrate the ability to process a request to switch on retailer-defined special read date as per the service agreement and generate appropriate charges for the retailer			
14.1.23.5	Demonstrate the ability to manage ten or twenty day contest period when switching between retailers as per OEB requirements			
14.2	Billing Related			
14.2.1	Demonstrate that the system can support an interface to an external complex billing engine such as Lodestar which will provide interval meter data for processing.			
14.2.2	Demonstrate that the system once interfaced, can import and process NSLS files daily from Lodestar.			
14.2.3	Demonstrate that the system, once interfaced to an external complex billing engine such as Lodestar, can process Hourly Ontario Energy Price (HOEP) files daily			

14.2.4	Demonstrate that the system, once interfaced to a complex billing engine such as Lodestar, can process weighted Average Hourly Spot Price (WAHSP) files daily			
14.2.5	As part of the process for generating usage transactions, process a DCI file for 3rd party meter readers and process returned DCO files for non-interval meter data			
14.2.6	As part of the process for generating usage transactions, Validate, Estimate, Edit (VEE) appropriate usage depending on billing option and type of account within the OEB-mandated timeframe			
14.2.7	Send Usage transactions by billing period and customer based on published meter reading schedule within the OEB-mandated timeframe			
14.2.8	Send usage for flat rate accounts			
14.2.9	While cancel and re-billing over a number of months, take into account enrollment history in order to send the correct cancel usage transactions to the correct retailer for the correct usage periods			
14.2.10	Cancel usage transactions regardless of billed status			
14.2.11	Receive and process Invoice Bill Ready Lines from retailers in support of Distributor Consolidated billing			
14.2.12	Demonstrate the automatic rejection of incoming Invoice Bill Ready Lines.			
14.2.13	Automatically create and transmit Invoice Bill Ready Lines to retailers for Retailer Consolidated billing			
14.2.14	Demonstrate the process for correction and resubmission of Invoice Bill Ready Lines if initially rejected			

14.2.15	Demonstrate the creation and transmission of ISDs and ISTs for multiple retailers.			
14.2.16	Interfaces - to Settlement systems / MV()			
14.3	Acknowledgements/Status Advice/Application Advice Transactions			
14.3.1	Generate Functional Acknowledgements for all incoming documents with the appropriate status			
14.3.2	Process Functional Acknowledgements for all outbound documents and log any errors reported for online processing			
	Process or generate all required Status Advice transactions including:			
14.3.3	> Terminate Transfer Request			
14.3.4	> Notice of Pending Switch			
14.3.5	> Contest Period Over – Won			
14.3.6	> Contest Period Over – Lost			
14.3.7	Demonstrate that the system can automatically process or generate all required Application Advice transactions, with particular attention to responses to Usage transactions and Invoice Bill Ready transactions			
14.3.8	Seamless moves			
14.3.8	Other			
14.3.8.1	Demonstrate that the system automatically stores and make available to users essential retailer information such as OEB license number, and available billing options as per the service agreement, as well as business and technical contacts to facilitate inter-business communications			
14.3.8.2	Able to resend the same EBT's, for instance when the Retailer does not receive the original transaction			

14.3.8.3	Explain the complexity of changing a bill print design to meet ongoing changes as set by the OEB or Ministry of Energy.			
14.4	Workflow			
14.4.1	Enrols			
14.4.1.1	> Distributor Bill Ready Enrolment			
14.4.1.2	> Retailer Bill Ready Enrolment			
14.4.1.3	> On Cycle Read Enrolment Request			
14.4.1.4	> Specified Read Enrolment Request			
14.4.2	Enrol DCBR Rejects			
14.4.2.1	System rejects Enrol for Invalid name and address			
14.4.2.2	System rejects Enrol because customer already in contest			
14.4.2.3	System automatically rejects an Enrolment because prudential requirements will be exceeded by total customers and/or total dollars as appropriate			
14.4.3	Enrols			
14.4.3.1	Automatically create a service order for a special meter read with appropriate charges if specified read requested by retailer			
14.4.3.2	Automatically assign appropriate fees for each enrolment requested by the retailer			
14.4.3.3	Automatically charge the retailer for every processed enrolment			
14.4.3.4	Send the calculated effective date based on the meter read schedule and blackout periods in the enrolment accept transaction.			

14.4.3.5	Demonstrate that the system can automatically update rate codes on customer's services to match the last SSS rate code and billing method when a customer enrolls.			
14.4.3.6	Demonstrate the processing of a Status Advice - Terminate Transfer (SA-TXR) when received.			
14.4.3.7	Notify customer of processed SA-TXR			
14.4.3.8	Demonstrate that the system can automatically send Status Advice - New Effective Date (SA - NED) if there is any change from the original calculated effective date			
14.4.3.9	Demonstrate that the system can automatically identify and notify both retailers of a contest using Status Advice - Notice of Pending Switch (SA-NPS).			
14.4.3.10	Demonstrate that the system can automatically notify both retailers of the results if the contest using Sates Advice - Contest Period Over (SA-CPO).			
14.4.3.11	Demonstrate that the system can automatically process Terminate Transfer (TXR) from either retailer during contest period.			
14.4.4	Inbound Drops			
14.4.4.1	> Next Scheduled or on Cycle Drop Request			
14.4.4.2	> Drop Request			
14.4.4.3	> Drop Reject- Invalid Information			
14.4.4.4	> Drop Reject- Consumer not with Retailer (already dropped??)			
14.4.4.5	> On Cycle Read Enrolment Request			
14.4.4.6	Demonstrate that the system can automatically create a service order for a special meter read with appropriate charges if specified read requested by retailer			

14.4.4.7	Automatically assign appropriate fees for each drop request.			
14.4.4.8	Charge the retailer for every processed drop.			
14.4.4.9	Send the calculated effective date based on the meter read schedule and blackout periods in the drop accept transactions.			
14.4.4.10	Demonstrate that the system can automatically update rate codes on customer's services to match last retailer's rate code and billing method			
14.4.4.11	Demonstrate that the system can automatically process SA- TXR to cancel drop request prior the completion			
14.4.4.12	Demonstrate that the system can automatically notify customer of a cancel of a drop.			
14.4.4.13	Demonstrate that the system can automatically send SA- NED if there is any change from the original calculated effective date.			
14.4.5	Outbound Drops			
14.4.5.1	Create outbound drop on customer's request.			
14.4.5.2	Process outbound drops on next scheduled meter read, specified, or on cycle.			
14.4.5.3	Demonstrate that the system can automatically assign processing fees for outbound drops.			
14.4.5.4	Demonstrate that the system can automatically send drop request containing the calculated effective date of the drop.			
14.4.5.5	Demonstrate that the system can automatically create a special work order is if a specified read is requested and the retailer is not charged.			

14.4.5.6	Demonstrate that the system can automatically update rate codes on customer's services to match last retailer's rate code and billing method			
14.4.5.7	Send SA- NED if there is any change from the original calculated effective date.			
14.4.6	Change Billing Options			
14.4.6.1	> Distributor Bill Ready Enrolment			
14.4.6.2	> Retailer Bill Ready Enrolment			
14.4.6.3	Demonstrate that the system can automatically create a service order for a special meter read with appropriate charges if specified read requested by retailer			
14.4.6.4	Demonstrate that the system can automatically charge appropriate fees for each change billing option request by a retailer			
14.4.6.5	Demonstrate that the system can automatically charge the retailer for every processed change billing option.			
14.4.6.6	Demonstrate that the system can automatically send the calculated effective date based on the meter read schedule and blackout periods in the change billing option accept transaction.			
14.4.6.7	Demonstrate that the system can automatically update rate codes on customer's services to match last SSS rate code and billing method			
14.4.6.8	Demonstrate that the system can automatically process SA- TXR when a change billing option is received.			
14.4.6.9	Demonstrate that the system can automatically notify the customer of a cancel of an change billing option.			
14.4.7	Usage Transactions			

14.4.7.1	Demonstrate that the system can automatically generate and transmit outbound usage transactions by noon on the 4th business day after meter read upload .			
14.4.8	Invoice Bill Ready Outbound			
14.4.8.1	Demonstrate that the system can automatically generate and transmit IBR's within 12 days of sending usage transaction			
14.4.9	Invoice Bill Ready Inbound			
14.4.9.1	Demonstrate compliance with Bill 210 legislation including storing of data for IMO settlement			
14.4.9.2	Reject Inbound IBR is rejected if service period was already billed after a user definable number of days after the usage transaction has been sent. On IBR billing prevent a bill from being created if the IBR bill window has not passed since the usage was sent.			
14.4.9.3	If IBR rejected due to missed bill window, process and bill replacement			
14.4.10	Change Consumer Information (CCI)			
14.4.10.1	Automatically generate and send a CCI whenever a change in the customer's pertinent information is made.			
14.4.10.2	Demonstrate that the system can automatically send CCI Inbound to worklist for verification prior to processing			
14.4.11	Inbound			
14.4.11.1	Demonstrate that the system can automatically generate CCI reject if inbound CCI fails validation			
14.4.11.2	Demonstrate that the system can automatically generate CCI accept if passes validation when changes complete including effective date			
14.4.12	Outbound			

14.4.12.1	Demonstrate that the system can automatically generate and transmit outbound CCI when Billing or Service address changes are made			
14.4.12.2	Demonstrate that the system can automatically change consumer information requests and accept responses will include all information that was communicated to the retailer			
14.4.13	Change Consumer Location			
14.4.13.1	Demonstrate that the system can automatically generate outbound CCL when moving customer matches OEB- defined criteria			
14.4.13.2	Demonstrate that the system can automatically send CCL Inbound to worklist for verification prior to processing			
14.4.13.3	Demonstrate that the system can automatically generate CCL accept if the transaction passes validation when changes are completed including effective date			
14.4.13.4	>Demonstrate that the system can automatically, if CCL, notify both retailers if in contest			
14.4.13.5	>Automatically generate appropriate STR fees for CCL			
14.4.13.6	>Generate CCL reject if inbound CCL fails validation			
14.4.13.7	>Allow the user to generate a drop transaction from the competitive retailer at the customers request, when the customer is also involved in the Location Change process.			
14.4.13.8	Demonstrate that the system can automatically send CCL when the customer is moving within LDC territory			
14.4.13.9	>Generate CCL accept transaction			
14.4.13.10	Blank			

14.4.13.11	>Automatically generate a Drop Request if moving customer does not meet OEB- defined criteria.			
14.4.14	Change Effective Date of Customer Location Change			
14.4.14.1	Automatically send SA-NED if move date changes			
14.4.15	Response Processing			
14.4.15.1	Demonstrate that the system can automatically process all status advice, reject response and accept response transactions received by the LDC			
14.4.15.2	Automatically process all accept responses that pass validation.			
14.4.15.3	Automatically notify the user when any late rejects are received.			
14.4.15.4	Automatically process and display any rejects in a user friendly work area.			
14.4.15.5	Automatically process and display any status advices received from a retailer including terminate transfer requests.			
14.4.15.6	All reject reasons comply with standards			
14.4.15.7	Users can maintain reject reasons when EBT standards change without programming.			
14.4.16	Retailer Associated Customer Billing			
14.4.16.1	Demonstrate that the system can recognize that and IBR waiting period has been met or missed after the Usage has been sent to Retailer.			
14.4.16.3	Demonstrate that the system can recognize that usage has not been sent.			
14.4.16.5	Demonstrate an example of a Retailer's message on a Customer's Invoice.			
14.4.16.6	Demonstrate that when the IBR has not been received from the Retailer, the system will still bill.			

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14.4.16.7	Demonstrate that ISD Cancels/IBR Cancels/Usage Cancels are automatically created when a service's usage is adjusted after being billed.			
14.4.16.8	Demonstrate that ISD's and IST's are generated according to Bill 210 requirements			
14.4.16.9	Demonstrate a demand-based Usage XML			
14.4.16.10	Demonstrate weekly non-billing informational Usage for Interval customers.			
14.4.16.11	Demonstrate that Usage XML transactions are automatically generated			
14.4.16.12	Demonstrate and explain the automatic process for loading of Pricing Tables used in billing.			
14.4.17	Import			
14.4.17.1	Demonstrate that the import of EBT XML Transactions is automated.			
14.4.18	Blank			
14.4.18.1	Blank			
14.4.19	Pip and PIPE Generation			
14.4.19.1	Demonstrate that a complete XML file can be generated in a batch process or individually.			
14.4.20	Spoke and XML related			
14.4.20.1	Demonstrate a centralized validation of Inbound / Outbound transactions			
14.4.20.2	Automatically charge the requesting retailer a fee for each inbound transaction based on the transaction type derived from a table.			
	Automatically retrieve the following parameters for validation			
14.4.20.3	>The number of days in a contest period			

14.4.20.4	>The number of days required for a blackout period prior to a scheduled meter read			
14.4.20.5	>The number of days given as a grace period to Retailers prior to dropping customers on requests initiated by the customer			
14.4.20.6	>The number of days that the transaction effective date is extended on a missed scheduled meter read. Demonstrate the system can identify that a regularly scheduled meter read was missed when a drop or enroll transaction and schedule a manual reading.			
14.4.20.7	>Demonstrate that the system can automatically identify the number of days required for lead time for a specified meter read			
14.4.20.8	>The number of days that scheduled reads will be checked for after a transaction's effective date			
14.4.20.9	>The number of days past the current date that a transaction effective date may be determined			
14.4.20.10	>The number of business days past a transaction's effective date before a missed scheduled meter read is flagged			
14.4.20.11	Demonstrate that the system can recognize that other pending transactions are in conflict, including duplicate transactions. Conflicts result in appropriate rejections.			
14.4.20.12	Demonstrate that when receiving an IBR the Cross-Reference number is used to locate a valid usage otherwise the IBR is rejected			
14.4.20.13	Demonstrate that the system can automatically verify that the retailer submitting the request is an active retailer set-up in CIS			

14.4.20.14	Demonstrate that the system can automatically verify during the process that the Enrol Request account number belongs to the retailer submitting the transaction			
14.4.20.15	Demonstrate that when the transaction is an Enrol Request the system automatically verifies that the account is not already enrolled with the retailer			
14.4.20.16	Demonstrate that the system automatically ensures that the account number belongs to a utility account, and service type is electric and the status is not disconnected or removed			
14.4.20.17	If the transaction is an Enrol Request, check to see if the account is in arrears or not. Accounts which are in arrears may not be enrolled.			
14.4.20.18	Validate all mandatory transaction fields against the CIS database			
14.4.20.19	Demonstrate that when a specified read date has been requested by the retailer, the system automatically ensures that the date is not outside of an acceptable period in the future			
14.4.20.20	Demonstrate that the system automatically ensures that the specified date is on a business day			
14.4.20.21	Demonstrate that the system automatically creates work orders for special reads for the services which do not have a scheduled read on the scheduled read date determined			
14.4.20.22	Demonstrate that the switch date would automatically be set to the next scheduled meter read date for certain transaction types such as Enrol Request, Drop Request etc.			
14.4.20.23	RPP True Up			

End of Section

Table 10.2.16. Retailer Management

15.0 RETAILER MANAGEMENT				
Item	Function / Feature	Vendor Score	Comments	Work Effort
15.1	Retailer Entity			
15.1.1	Retailer Identification and Access			
	Provide the ability to access the retailer by the following key fields:			
15.1.1.1	> Retailer Name with Partial Search Capability			
15.1.1.2	> Federal Business Identification Number			
15.1.1.3	> Doing Business As Name (D.B.A.)// Business Name			
15.1.1.4	> Phone Number (Cell Phone) Need more than one number with ext.			
15.1.1.5	> Customer Identification Number			
15.1.1.6	Provide for a combination of search criteria e.g. Customer number and name.			
15.1.2	Retailer Status or Situation			
15.1.2.1	Demonstrate that when the account is accessed the system can highlight negative history, open contact items, cash only status of the retailer.			
15.1.2.2	The system will readily distinguish between current retailers receiving services and potential retailers.			
15.1.2.3	View at a glance all customer's associated with the specific retailer, provide query and export capabilities			
15.1.2.4	Able to reject all transactions from a retailer if desired.			
15.2	Retailer Set-up and Link			
15.2.1	Generate a Customer Profile and Billing account number, assisting the user in the process of entering and validating retailer information.			

15.2.2	Establish the retailer in the system and immediately link it to a single account number.			
15.2.3	Establish the retailer in the system and immediately link it to multiple customer accounts, multiple customer services, and/or multiple customer premises.			
15.2.4	Suspend or store an incomplete retailer application in a temporary work area for later reactivation and completion.			
15.2.5	The Retailer can establish various addresses including; service addresses, mailing addresses, temporary addresses, etc.			
15.3	Retailer Based Information			
15.3.1	Information specific to the Retailer is maintained or is associated with their customers.			
	This information includes:			
15.3.2	> Billing History			
15.3.3	> Payment History			
15.3.4	> EBT exchanges			
15.3.5	> Credit Profile History			
15.3.6	> Retailer ID (OEB Licence number) and GST Registration number			
15.3.7	> Retailer contact names and numbers			
15.3.8	> Mailing Addresses			
15.3.9	> Deposit Information			
15.3.10	> Customer/Retailer Correspondence (inbound and outbound)			
15.3.11	> Contracts in Effect			
15.3.12	> Doing Business As Name (D.B.A.)			
15.3.13	> Phone Number(s) (Cell phone, Unlisted phone, etc.)			
15.3.14	> Email Address(es)			
15.3.15	> Fax Number (s)			
15.3.16	> Primary SIC			
15.3.17	> Headquarters and Branch Locations			
15.3.18	> Emergency Contact (Name and Method of Contact)			

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15.3.19	Supports user defined fields for the Retailer entity.			
15.3.20	Ability to generate standard and dynamic reports relating to retailer profiles both at the detail and summary level.			
15.3.21	Retailer Charges			
15.3.21.1	Demonstrate that the system can automatically generate Invoice Market Participant charges on a monthly basis and send to the retailer			
15.3.21.2	Demonstrate that the system can automatically and continually calculate and store on the retailer's account prudential amounts for each retailer			
15.3.22	Retailer Correspondence			
15.3.22.1	Maintain on-line history of all inbound and outbound correspondence.			
15.3.22.2	Document specific customer correspondence received, i.e.. date, specific comments, including date/time they called etc.			
15.3.23	Credit Profile			
15.3.23.1	Credit profile information is provided including user defined fields.			
15.3.23.2	View a customers credit profile for a customer across all accounts. System has the ability to combine multiple accounts together to provide a "credit at a glance" function.			
15.4	Retailer Transactions			
15.4.1	Process payments to and from retailers			
15.4.2	Search for specific transaction types and dates; export results to Excel, etc			

End of Section

Table 10.2.17. Complex Billing Engine

16.0 Complex Billing Engine			

Item	Function / Feature	Vendor Score	Comments	Work Effort
16.1	Storage of Interval Reads			
16.1.1	Able to import meter reading files in different file formats including MV-90, CMEP, XML, MDEF,			
16.1.2	Store interval reads, from electrical residential and industrial interval meters as used on Ontario			
16.1.3	Edit interval reads, from electrical residential and industrial interval meters as used on Ontario			
16.1.4	Able to manage any interval			
16.1.5	Able to roll to read intervals into other intervals, for instance 5 minutes to 15 minutes or 15 minutes to hourly			
16.1.6	Able to measure power factor, using a minimum of two channels. Describe any limitations on the different channels with different units of measure.			
16.1.7	Ability to handle multiple channels with different configurations (UOM codes) as supplied by various automated meter reading systems.			
16.1.8	Able to apply primary metering allowance and distribution loss factor			
16.2	Billing			
16.2.1	Able to handle multi level demand periods for multiple channels. Able to determine peak in various defined time period.			
16.2.2	Users easily able to define complex rate schedules based on seasons, time of day, and size of customer.			
16.2.3	Able to perform real time pricing, able to apply different prices for any defined time period such as an hour or any defined TOU time range.			
16.2.4	Able to bill off cycle easily as required.			

16.2.5	Able to bill some charges based one demand calculation and other charges on another demand calculation for the same time period.		
16.2.6	Able to bill based an individual customer period weighted average price, calculating the price and quantities.		
16.2.7	Able to model billing for an account, based on differing rates or load profiles.		
16.2.8	Able to bill demand on residential smart meters in different time of use periods.		
16.2.9	Able to calculate the NSLS and period weighted average price (hourly daily monthly) as defined in Ontario, preliminary and final. With on the fly group adjustments. If when calculating information for an account is not available, continue the calculation without the account and produce and error report.		
16.2.10	Create billing determinant files for an external billing system		
16.2.11	Able to edit billing determinants		
16.3	Functions		
16.3.1	Data viewer tool, shows graphs of interval data for a customer, or a group of customers, including analytic tools, shows different interval lengths.		
16.3.2	Can export data to desktop tools, and import from desktop tools.		
16.3.3	Integrate customers, meters and account with external systems, including the Automated Meter Reading system.		
16.3.4	The Retailer can establish various addresses including; service addresses, mailing addresses, temporary addresses, etc.		

16.3.5	Virtual device calculator to aggregate multiple meters to one account		
16.3.6	Group calculator, able to define a virtual device based on groups of accounts.		
16.3.7	EST / DST time zone capabilities. Meters in local time or EST, billing outputs are in EST. Rate calculations could be in either local time or EST.		
16.3.8	Able to import IESO statements		
16.3.9	Able to import IESO data files		
16.3.10	Able to compare IESO data files to IESO statements and to other meter readings		
16.4	Reporting and Queries		
16.4.1	Able to define accounts as a group and report on the group		
16.4.2	Able to store NSLS calculations and what contributed to the calculation when it occurred, historically for an audit trail		
16.4.3	Maintain all versions of data streams for audit trail, raw, edited, corrected, billed, etc.		

End of Section

10.3. Appendix C – Process Scripts

Process Scripts

Demonstration of Ontario Ready Software

Objective

The Group is interested in exploring vendors' readiness to supply Customer Information and Billing software that is ready for the Ontario Market. The Group would like to see vendors demonstrate the features of their software.

The critical features required in the Ontario Market are:

EBT Transactions

Billing

Rebate Processing

Rate Flexibility

Critical Outcomes

EBT transactions

EBT transactions are generally created by the system as a by-product of normal CIS processes without user intervention. For example, if the CSR sets up an out of territory move for an enrolled customer the drop EBT is automatically sent to the retailer. If the CSR changes the date of the move the status advice EBT is automatically sent to the retailer.

Accept and reject transactions for valid incoming EBT transactions are created without user intervention, for example, historical usage accept/reject, IBR accept/reject, enroll accept/reject and drop accept/reject.

Through configuration, users can decide to automatically reject error transactions or review them and then decide to accept or reject. Where incoming EBT transactions are edited and not automatically accepted or rejected, users have friendly screens to review, accept and reject incoming EBT transactions where required. These screens present the users with information needed to resolve possible error situations in a friendly manner. New edits can be created quickly.

Users can find EBTs by retailer, by transaction type, by date and by account and find all related transactions in a transaction flow, for instance in a switch. The associated CIS transaction can be easily found for any EBT (for example, the meter reading transaction related to the usage, the move service order with the drop transaction, the billing transaction with the IBR for retailer consolidated billing).

Users can easily see the enrolment history for an account including the pending retailer.

The ISTs and related ISDs can be easily reviewed, and related to the associated customer accounts.

Unbilled IBRs can be reviewed.

A new retailer can be added easily. All transactions for a retailer can be rejected if desired.

The system sends and receives large volumes of transactions promptly.

The vendor can quickly quote a change to EBT standards and quickly implement EBT changes.

The users can easily identify transactions rejected by retailers, and transactions where the retailer has not responded on a timely basis.

Billing

All types of billing required by the Ontario rules are fully supported.

Rebate processing

The system can create and update accounts with rebates with little effort. This involves prorating historical billed usage into calendar periods for any account, and applying a usage based charge to the applicable accounts.

Rate Flexibility

Users can create new charges without programming. Users can create new rate schedules quickly.

Table 10.3.1. Test Scripts

	Demonstrate billing new TOU rate for a residential customer, including the use of critical peak pricing. Explain how the user would set up the rate.
	Demonstrate setting up a new charge based on loss adjusted usage for a residential account on TOU pricing. Assume for example there is a new additional debt retirement charge.
	Demonstrate NSLS billing and how the pricing is updated.
	Set up a new charge based on daily pricing and loss adjusted usage.
	Demonstrate the LDC consolidated billing cycle, for price protected and non-price protected customers, and interval customers including EBT's. Show the meter read, send usage EBT, receive IBR, bill customer and settlements with the retailer.
	Demonstrate the Retailer consolidated billing cycle, for residential and interval customers, from meter reading to settlements with the retailer.
	Demonstrate a cancel and re-bill for LDC consolidated billing including all associated EBT's including the settlements invoice.
	Demonstrate the users environment to edit and review EBT's where required. Demonstrate how a user would modify the reject reasons in EBT's. Demonstrate the users environment for inquiring on EBT's by retailer, by transaction type, by transaction reference number and by date.
	Demonstrate enroll a customer from SSS.
	Retailer requests a change from price protected to non-price protected. Show billing before and after the change as well as processing the CBO EBT.
	Enroll a customer already enrolled with another retailer, current contract is LDC consolidated, future contract is retailer consolidated. Demonstrate all changes associated with the customer account.
	Enrolled customer moves retroactively outside the service territory. Assume usage has been sent to the retailer for a period after the move took place.
	Enrolled customer moves inside the service territory, and changes the time of the move. Retailer accepts the customer at the new location.
	Customer moves inside the service territory, and retailer rejects the customer at the new location.
	Retailer requests historical usage, high volume of accounts, all interval accounts.

	Retailer requests historical usage, account fails 2 of 3 validation
	Retailer requests historical payment, account is closed.
	Retailer requests historical payment information, transaction is valid.
	Retailer sends an IBR outside the billing window.
	User changes the size of the billing window where an IBR is acceptable from 3 days to 7 days.
	Retailer sends change bill option – customer moving from retailer consolidated to LDC consolidated billing
	Retailer sends change consumer information transaction. LDC holds EBT for review, and then accepts the data
	Retailer sends change consumer information transaction, LDC holds EBT for review and then rejects the data.
	Customer is set up for a move in territory and CCL has been sent. Customer changes mailing address on the account. Show the CCI transaction and subsequent move flow.
	Retailer requests an enroll and customer is in arrears for \$200. LDC rejects the enroll.
	Retailer requests drop and drop requested date is 2 years in the past.
	Demonstrate the steps the user would go through to rebate all customers in rate groups < 50 kw with a charge based on 2% of loss adjusted usage from February 1, 2005 to November 30, 2005. Customers have monthly and bi-monthly billing cycles.
	Show how the LDC would identify the customer billing transaction related to a particular ISD. Retailer has provided the transaction reference number of the ISD.
	Show how the LDC would find all IBR's for a customer enrolled with a retailer.
	Show how the LDC would find all CCL's sent on a particular date. Show how the LDC would identify the move transaction in the CIS associated with a particular CCL EBT.
	Show how the LDC would identify all unbilled IBR's for a retailer.
	LDC decides to manually review all incoming enroll transactions if the customer is moving inside the service territory. Show what would be involved in setting up this edit.
	Explain what would be involved in setting up a new retailer.
	A customer is scheduled to enroll with a retailer on the next bill. The customer changes their mailing address.
	Show how the CSR would review the enrollment history for an account, including the pending retailer.
	The retailer has rejected an IST and all associated ISD's because the sum of the ISD's do not equal the IST. What would the user do to investigate and resolve the issue? Assume retailer can provide little information.
	Demonstrate the process used to re-evaluate deposits according to the OEB rules, increasing and decreasing customer deposits where required.

10.4. Appendix D - Price Sheets

Price Sheets

Table 10.4.1. Hosting Costs

Hosting Service	One-time cost item (specify)	Fixed Cost	Per Unit Charge	Total Cost	Applicable Discounts	Total Cost net of Discounts	Comments
Server Administration							
Security Administration							
etc.							

Table 10.4.2. Travel and Living

[illegible]

Table 10.4.3. Documentation

[illegible]

Confidential Information is not to be shared with any other party without the prior written consent of Enersource Hydro Mississauga Inc. & Toronto Hydro Electric System Ltd.

Table 10.4.4. Training and Change Management

Staffing Category	\$ Fixed cost	Number of Staff	Hourly Rate	Estimated Hours	Total Costs	Applicable Discounts	Total Cost net of Discounts	Comments

Table 10.4.5. Project Management

Staffing Category	\$ Fixed cost	Number of Staff	Hourly Rate	Estimated Hours	Total Costs	Applicable Discounts	Total Cost net of Discounts	Comments

Table 10.4.6. Unique Customization Costs

Staffing Category	\$ Fixed cost	Number of Staff	Hourly Rate	Estimated Hours	Total Costs	Applicable Discounts	Total Cost net of Discounts	Comments
Configuration Team								
Common Interfaces Team								
Common Customization Team								
etc								

Table 10.4.7. CIS Implementation Costs

Staffing Category	\$ Fixed cost	Number of Staff	Hourly Rate	Estimated Hours	Total Costs	Applicable Discounts	Total Cost net of Discounts	Comments
Configuration Team								
Common Interfaces Team								

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Common Customization Team								
etc								

Table 10.4.8. Maintenance Fees

Modules/services	Description	\$ Fixed cost	\$ Variable cost	Applicable Discounts	\$ Total cost, net of Discounts	Comments
CIS						
Ontario Market Modifications						
Data Modeler						
Software Testing Tools						
Data Warehouse/Business Intelligence/Executive Dashboard						
Archiving						
Complex Billing Engine						
Test Region Building Tools						
Customer Web Portal						
Additional Software						

Table 10.4.9. Licence Fees

Modules/services	Description	\$ Fixed cost	\$ Variable cost	Applicable Discounts	\$ Total cost, net of Discounts	Comments
\$						
ta Modeler						
ftware Testing ols						
ta arehouse/Business elligence/Executive shboard						
hiving						
mplex Billing gine						
st Region Building ols						
ustomer Web Portal						
ditional Software						

10.5. Appendix E: Notice of Intent to Respond

Notice of Intent to Respond

NOTICE OF INTENTION TO RESPOND / DECLINE TO RESPOND

Instructions: Suppliers are requested to complete and return this form by facsimile to Enersource Corporation at 905-566-2737, attention: Purchasing Department by April 5, 2006. Please note that failure to return this form does not disqualify a supplier from submitting a proposal by the submission deadline.

Supplier's business name and mailing address:

Please indicate your election by putting an X in the appropriate box:

The Supplier will respond to this RFP: ☐

The Supplier will not respond to this RFP: ☐

Date:

Signature of Authorized representative

Name:

Position:

10.6. Appendix F: Vendor Declaration

Appendix F
Vendor Declaration

Please complete the following form and submit it with your Proposal.

To: Enersource Corporation
3240 Mavis Road
Mississauga, ON
L5C 3K1

Attention: Ramona Hendry

The undersigned (the "Vendor") having received and carefully examined the Request for Proposals EC2006-008 Customer Care and Billing Solution (the "RFP") dated March 27, 2006 and issued by Enersource Corporation ("Enersource") on behalf of its affiliate, Enersource Hydro Mississauga Inc. ("EHM") who is acting on behalf of itself and Toronto Hydro-Electric System Limited ("TH") (EHM and TH hereinafter referred to as the "Group") and all documents provided by the Group in connection therewith, and having satisfied itself as to the meaning and effect of all provisions contained therein, hereby submits this Proposal to perform the Customer Care and Billing Solution on the terms described in this Proposal.

1. Capitalized terms used in this Proposal that are not otherwise defined herein shall have the meaning ascribed to them in the RFP.
2. This Proposal has been signed in strict compliance with the RFP.
3. Without limiting the rights of the Group, the Vendor acknowledges and agrees that nothing contained herein, in the RFP, or in any documents connected therewith, nor any act done or expense incurred by the Vendor in the preparation and submission of this Proposal, nor any trade or industry custom or practice, nor any representation or assurance that may have been made or given to the Vendor by or on behalf of the Group, in any circumstances, shall in any manner bind Enersource or the Group to accept this Proposal or any other Proposal, regardless of the form or content of this Proposal or any other Proposal. The Vendor further acknowledges and agrees that the Group may, in their discretion, reject any or all Proposals or may accept any Proposal in whatever manner, at whatever Proposal price, on whatever terms and for whatever reasons the Group, in its discretion, considers appropriate, all without liability or obligation of any kind to any Vendor. The Group may also negotiate separately with one or more Vendors after receipt of Proposals by the Group.
4. If this Proposal is made by more than one individual, person or entity, then each agrees to be bound jointly and severally by this Proposal.

Confidential Information is not to be shared with any other party without the prior written consent of Enersource Hydro Mississauga Inc. & Toronto Hydro Electric System Ltd.

5. The Vendor submits with this Proposal a duly completed response to the Functional Checklist.

6. The Vendor represents and warrants to the Group that:

all requirements for the completion and submission of this Proposal have been complied with;

this Proposal is made without any connection with, comparison of information or arrangements with, or information from or regarding, any other Vendor and is, in all respects, made fairly and without collusion or fraud;

no party associated with the Vendor is, or may become, financially interested, directly or indirectly, in any aspect of the Customer Care and Billing Solution, other than in the appropriate discharge of his/her obligations as an employee, agent, officer or otherwise of the Vendor; and that

the Vendor has read, understood and agrees to be bound by and to abide by all provisions contained in the RFP and any materials provided in connection therewith.

All written communications from the Purchasers to the Vendor, shall be deemed to have been received and acknowledged by the Vendor, if delivered to an adult person at the mailing address that the original RFP was delivered.

THIS PROPOSAL made this _____ day of _____, 2006.

[Insert name and title]

[Insert name and title]

I am authorized to bind [insert Vendor name]

I am authorized to bind [insert Vendor name]

Date:

Date:



3240 Mavis Road
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www.enersource.com

SEC # 30

Addendum #1 RFP #EC2006-008 Customer Care and Billing Solutions

This addendum, issued March 30, 2006, must be incorporated into, and made part of, the above noted proposal document.

1. Please note the following date changes pertaining to the RFP mentioned above:

Referenced in: *6.2. Vendor Questions Due*

Where the date says April 7, 2006, please change to April 10, 2006

Referenced in two locations in: *6.3. Vendor Proposal Due*

Where the date says April 20, 2006, please change to April 24, 2006

2. Replies to the Function and Features Checklist, referred to in table 9.2 Appendix B, must be returned in Excel format on the CD version of the submitted proposal. We are attaching an electronic copy of this table for ease of entry.
3. The non mandatory bidders meeting is scheduled for Friday, March 31, 2006 at 10:00 a.m. at Enersource Corporation, 3240 Mavis Road.

All other terms and conditions remain the same. This addendum must be acknowledged in the submitted proposal document.

Rosanna Procopio
Buyer



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SEC#30

Addendum #2 RFP #EC2006-008 Customer Care and Billing Solutions

This addendum, issued April 13, 2006, is incorporated into, and part of the above noted proposal document.

Question #1:

Please send any diagrams / schemas of Toronto Hydro's and Enersource Hydro's interfaces to their current CIS environments. This will assist in our estimation / pricing.

Answer #1:

The integration needs from the RFP contain both the current state interfaces as well as the future state, see Section 2.7. The overall integration need to the CIS depends on which components are provided for the customer Web interface.

Question #2:

Please send a new pricing worksheet in Section 10.4 for Table 10.4.9. The descriptions in the left-hand column are not fully visible.

Answer #2:

A new pricing sheet is provided in this addendum – see attachment}.

Question #3:

Table 2.7.2, TH Interfaces, does not list an Element/Description for items 14 and 15. Are these specific, existing interfaces or generic placeholders for desired interfaces?

Answer #3:

This is a report that is emailed to two collection agencies. The same report format is used for both agencies and there is a business rule that allocates the work to the two agencies based on their recent performance. The change to the report parameter is done manually. The current report is written in Oracle Reports (or in C – MIR to check and confirm).

Question #4:

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RFP #EC2006-008
Customer Care and Billing Solutions

The vendor's data conversion responsibilities are outlined in section 4.6.2 (d), Product Conversion, and elsewhere in the RFP. Please provide more information on the data that must be converted from Toronto Hydro's and Enersource Hydro's legacy systems (including number of items and records in each of the databases).

Answer #4

Conversion data is attached from both Enersource and Toronto Hydro.
Toronto – We will provide a high level summary of the number of fields to be converted. We expect to convert 2 years of prior data. The rest will be available as an archive from the previous CIS and available via a distinct interface.
General - There is no prior history on what it will take to migrate the EBT data. This is being investigated and the response will take time.

Question #5

Table 2.1.1 references "2nd level Application Support." Please define this level of support and describe how it is different from 1st level Application Support, if appropriate.

Answer #5

1st level is call taking and follows ITIL definitions for how the configuration item is specified for redirect to 2nd level support. 1st level only resolves incidents that are replicable and subject to pre-defined scripts and standardized procedures.

Question #6

Please clarify the primary difference from the Group member perspective between Option 2 and Option 3.

Answer #6

Option 1 The vendor provides infrastructure, core (Ontario-localized regulatory and shared business process plus shared interfaces)) and custom (interfaces and special features per LDC instance) – i.e. outsourcing services.
Option 2 The LDC provides and runs the infrastructure and the vendor provides core, does the customization and provides application management services.
Option 3 The LDC provides and runs the infrastructure and does 1st level application support, vendor provides and updates the core product over time; performs 2nd level application support for core and does the initial custom interfaces (and initial 2nd level support during burn-in of custom) and the LDCs undertake the support of custom over time and 2nd level support of the custom.

Question #7

Can the group share any additional data about the evaluation criteria and planned empirical analysis referenced in Section 5?

Answer #7

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No.

Question #8

The RFP states that “each utility may individually determine, in its sole discretion, to select different vendors or CIS s or to not proceed with any of the proposals received for a CIS. Further, even if the Group does determine that it will proceed with a common CIS, each utility will enter into its own separate contract for the applicable successful proponent.” In the vendor’s response, then, is it necessary to include separate costs for each scenario (i.e. Option 2 for Enersource Hydro alone, Option 2 for Toronto Hydro alone, Option 2 for Enersource Hydro and Toronto Hydro together, etc.)?

Answer #8

Yes.

Question #9

Similarly, under section 2.2, Technical Requirements / Vendor Responsibilities, is it necessary to include three separate hardware sizing’s / hardware recommendations – one for Enersource Hydro, one for Toronto Hydro, and one for Enersource Hydro and Toronto Hydro together? Or is one hardware sizing / hardware recommendation for the Group sufficient?

Answer #9

For each option that you bid, you must include hardware sizing/hardware recommendations.

Question #10

In the software space there are many interpretations of what data modeling means and what the objective of data modeling should be. In order for SPL to respond appropriately, could you define for us what your definition of data modeling is and what your objectives of this exercise will be within the context of the project?

Answer #10

Data models are to be defined for the purpose of creating and supporting interfaces and reports. Therefore the data model details that are relevant are those elements that are or should be exposed to clients for this purpose. The metadata should be exportable for use with leading 3rd party reporting packages, for the development of middleware connectors and for custom point-to-point applications that need an unambiguous understanding of the meaning of data elements, the associated tables or parametric files that define the domain of each entity and element or any details that would be required to extend and develop reports and interfaces. The internal workings of the application apart from this need to integrate and use information outside the application are not relevant to this discussion.

Data modeling tools - there are no predefined choices at either Enersource or Toronto Hydro. However, the vendor recommendation on a data modeling tool will be subject

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to technical review by both parties. A list (with no implied preference) of commonly used tools would be Erwin, Rational Rose, Power Designer, Oracle Designer.

Question #11

Can you forward copies of the Vendor Declaration and Confidentiality Agreement in Word?

Answer #11

We will not be providing these documents in Word format.

Question #12

Can you reissue page 218 (table 10.4.9 license fees) our version is truncated. Also is it possible to get the pricing tables in Word.

Answer #12

The Licencing Fees document, Table 10.4.9 is being sent to you within this email in Excel format.

Question #13

How many years of data does the group (and individual) LDCs want to convert?

Answer #13

The LDC's request two years of data.

Question #14

Can you provide specifics on the data modeler requirements you have mentioned in the RFP. For example can you give examples of how you intend to use this type of tool?

Answer #14

Data modeling tools - there are no predefined choices at either Enersource or Toronto Hydro. However, the vendor recommendation on a data modeling tool will be subject to technical review by both parties. A list (with no implied preference) of commonly used tools would be Erwin, Rational Rose, Power Designer, Oracle Designer.

Question #15

What is the current batch window for Enersource and Toronto Hydro? What is the worst case batch window?

Answer #15

For Enersource the current is 4 hours, worst case is 6 hours based on current billing cycles
Toronto Hydro the current is 8 hours, worst is 12 hours based on current bi-monthly billing

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Question #16

How many contact centers are there and where are these locations located?

Answer #16

Enersource has two, both in Mississauga.
Toronto Hydro has two, both in Toronto.

Question #17

Can you provide for each contact centre:

- PBX used (make, model, release level)
- Type and release level of CTI Link to the PBX
- Total number of agents and total number of supervisors/managers
- Maximum number of agents and supervisors on one shift
- What is the peak hour
- Current and Projected peak hour call volume, average call length, average daily, weekly, monthly and yearly call volume
- Hours of operations
- Agent desktop (CPU, memory, screen resolution, OS, NIC)
- What type of LAN/WAN connection is there to the data center

Answer #17

Enersource – VoIP from Telus IPOne, no CTI at present, Internet connection - high speed. Agents 33, maximum per shift 33, peak hour 12 noon to 1pm, peak hour average call length 4.25 min, daily avg. 575, weekly 2,875, monthly 12,000, yearly call volume 145,000, hours of operation 24x7x365, agent desktop ??

Enersource IVR – transitioning to Microsoft Speechworks (on PC)

Toronto Hydro – PBX in transition currently Nortel

Key Functions 1) Distributes calls to various departments

Press 1 for Dispatch

Press 2 for Self serve (meter Reading)

Press 3 for Customer Service

2) Enables users to get their account balance

3) Enables users to enter their meter readings

4) Enables users to identify themselves by entering their meter number or account number. This information is then passed on to the CTI solution for screen POP.

5) Provides users with location and hour of operation information CTI is provided by Upstream Works

Key Function 1)

When the caller enters their account number or meter number in the IVR, CTI automatically starts the proper form when the call gets

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to the agent desktop. A screen with the specific account information is provided.

Maintenance Info:
7 X 24 - 365 days a year.

Question #18

During the bidders session you provided additional information on options 2 and 3. Could you provide in writing an expanded description of what specifically is the responsibility of the LDCs and the vendor in each option.

Answer #18

Please see the response for Question #6 in this addendum.

Question #19

Can you provide a list of transactions types you would expect a customer to be able to perform on the web portal?

Answer #19

Some typical transactions would include;
Enter meter reading
Make payments
Review bills
Establish conservation target for energy usage on a monthly basis
Review two years history in various billing blocks, time of use billing (on-peak, mid-peak, off-peak, critical peak) in various chart forms – bar, pie, line graph form.
Retrieve previous day's hourly consumption by 8am as directed by the Ministry of Energy.
Provide data on appliance inventory and lifestyle parameter for use in estimating consumption patterns and opportunities for conservation.
Update data on appliance inventory and lifestyle parameters
Others may be required.

Question #20

Can you provide the information you would expect to deliver to a customer over the phone using the IVR?

Answer #20

Please refer to Answer #26B in this Addendum.

Question #21

Can you provide details of your requirements for Data warehouse and BI?

Answer #21

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Enersource – not using any BI tools at the moment.

Toronto Hydro – Using Business Objects / Crystal environments internally

Recommendation on operational datastore and ETL for creating extracts and operational reporting to be provided by vendor as per RFP section

Question #22

Ontario Market Ready Demonstration

For the Ontario market demonstrations, given that there won't be a live EBT hub to connect to, what is your expectation for what needs to be shown

Answer #22

We would like to see a live demonstration using a test hub facility with the test hub acting as the retailer using Ontario EBT standards and we expect the hub to validate the transactions that the system is sending.

Question #23

Client Resources

- What is the maximum number of FTE client resources (Enersource & Toronto Hydro) that can be involved on the project

Answer #23

Dedicated, senior resources will be seconded for the project. We expect the vendor to identify the need for LDC resources in the project plan. Depending on the option being bid, the type of resources and degree of knowledge transfer will differ. The proposal should address this.

Question #24

Existing Technology

- What software/hardware components make up your existing IVR solution? What key functions does it support?
- What software/hardware components make up your existing CTI solution? What key functions does it support?

Answer #24

Enersource – IVR Microsoft Speechworks (on PC), no CTI in place
Toronto Hydro – IVR PBX in transition currently Nortel

Question #25

Maintenance Term

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- Can you please clarify the duration of the maintenance (application support) period - Section 6.12.4 indicates a maintenance and support services period of 8 years whereas Section 2.2 Technical Requirements discuss storage requirements over a 5 year period.

Answer #25

One duration addresses storage – the size of the initial hardware investment for the first five years. The other is a level of commitment to support the Ontario market for an extended period. There is no conflict in these durations.

Question #26

Clarification on the functional scope of the system to be procured

From the RFP document it is not quite clear which current systems of Enersource and Toronto Hydro are to be replaced.

- a) Should the system allowing customers to access some account information via internet and initiating requests be replaced or interfaced to?
- b) Should the current IVR system be replaced or an interface provided to it?
- c) What archiving system is currently in use?
- d) Is it intended to replace the existing archiving system?

Ideally the response would include a chart on the current and anticipated system landscape and details of the information to be exchanged, frequency, mode of exchange (on request, batch)

Answer #26

A) As examples of the type of Web access that we are contemplating, the following is a non exhaustive list;

- Enter meter reading
- Make payments
- Review bills
- Establish conservation target for energy usage on a monthly basis
- Review two years history in various billing blocks, time of use billing (on-peak, mid-peak, off-peak, critical peak) in various chart forms – bar, pie, line graph form.
- Retrieve previous day's hourly consumption by 8am as directed by the Ministry of Energy.
- Provide data on appliance inventory and lifestyle parameter for use in estimating consumption patterns and opportunities for conservation.
- Update data on appliance inventory and lifestyle parameters.

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- B) IVR is available at Enersource and Toronto Hydro and there is potential to look at options to address future needs. Vendors are welcome to suggest optimal arrangements to address this set of needs. We would expect to provide comparable but scaled services to those provided via the Web. The objective is to provide a uniform set of services via various channels, subject to the technical limitations of these channels.
- C) & D) The archiving solution would need to be specified and provided. The existing Toronto solution is MAK M-Datamanager. There is no Enersource archiving solution at present.

Question #27

Generally, the length of AMS and hosting contracts is five years. Is this the period the Group was anticipating?

Answer #27

Yes, subject to termination for cause.

Question #28

Is the anticipated AMS content in respect of first level support different for Option 1 and Option 2?

Answer #28

First level support is provided under Option 1 and not under Option 2.

Question #29

Please clarify whether the dates set as milestones for the decision process are still relevant. In particular the 10th May and the dates for the two software demos (six weeks from issue of RFP).

Answer #29

Yes, the dates are relevant at this time. The Bidders meeting on March 31st provided an opportunity to request additional time to prepare for the presentations. The intent was that such demonstrations would commence the week of May 1st.

Additional note:

A new pricing sheet is being provided, please use this document to submit your information.

All other terms and conditions remain the same. This addendum must be acknowledged in the submitted proposal document.

Rosanna Procopio
Buyer



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SEC # 30

Addendum #3 RFP #EC2006-008 Customer Care and Billing Solutions

This addendum, issued April 20, 2006, is incorporated into, and made part of the above noted proposal document.

Please find attached a revised copy of the Functional Checklist, noted as "Functional Checklist-revised 04-20-06", which is to be submitted as part of RFP # EC2006-008-Customer Care and Billing Solutions. Please use this version for your submission to this RFP.

There are no changes to the Item numbers and the Function / Features column data which were provided in both the original RFP and Addenda #1 and #2. Any other data provided as part of the previous Functional Checklist is not valid and does not form part of this RFP.

All other terms and conditions remain the same. This addendum must be acknowledged in the submitted proposal document.

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SEC # 30

Addendum #4 RFP #EC2006-008 Customer Care and Billing Solutions

This addendum, issued April 24, 2006, is incorporated into, and made part of the above noted proposal document.

1. Any required changes to your submission in reference to Addendum # 3 can be submitted in CD format. The CD version of the submission for the Functional Checklist will be the final official version.

2. The closing time for this RFP has been extended to April 25, 2005 @ 12:00 pm E.S.T.

All other terms and conditions remain the same. This addendum must be acknowledged in the submitted proposal document.

Rosanna Procopio
Buyer



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SEC # 30

Addendum #5 RFP #EC2006-008 Customer Care and Billing Solutions

This addendum, issued June 20, 2006, is incorporated into, and part of the above noted proposal document.

This is to advise you that Enersource Corporation is requesting an extension of an additional forty five (45) days from the Bid Expiry date to allow for further consideration of the submissions. The current bid expiry date is June 23, 2006. This request will now move the validity date to August 7, 2006.

All terms and conditions remain the same. This addendum must be acknowledged in the submitted proposal document.

Rosanna Procopio
Buyer



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SEC# 30

Addendum #6 RFP #EC2006-008 Customer Care and Billing Solutions

This addendum, issued August 2, 2006, is incorporated into, and part of the above noted proposal document.

This is to advise you that Enersource Corporation is requesting an extension of an additional forty five (45) days from the Bid Expiry date to allow for further consideration of the submissions. The current bid expiry date is August 7, 2006. This request will now move the validity date to September 21, 2006.

All terms and conditions remain the same. This addendum must be acknowledged in the submitted proposal document.

Rosanna Procopio
Buyer

FIXED ASSETS CONTINUITY SCHEDULE (000's)

	2008 <u>Test Year</u>	2007 <u>Bridge Year</u>	2006 <u>Historic Year</u>	2005 <u>Historic Year</u>	2004 <u>Historic Year</u>	2003 <u>Historic Year</u>	2002 <u>Historic Year</u>
Property, Plant & Equipment							
Opening Asset Value at Cost	820,103	778,434	751,820	724,575	689,033	658,376	625,618
Capital Expenditure - Additions	52,345	46,769	37,669	36,733	41,569	36,735	40,339
Adjustments (1)	(9,625)	(5,100)	(11,055)	(9,488)	(6,027)	(6,077)	(7,581)
Closing Asset Value at Cost	862,823	820,103	778,434	751,820	724,575	689,033	658,376
Opening Accumulated Depreciation	(364,994)	(335,449)	(313,429)	(290,731)	(265,445)	(242,462)	(222,643)
Depreciation Expense	(37,041)	(34,535)	(32,689)	(31,931)	(31,166)	(29,042)	(25,857)
Adjustments (1)	9,673	4,990	10,669	9,232	5,880	6,060	6,038
Closing Accumulated Depreciation	(392,362)	(364,994)	(335,449)	(313,429)	(290,731)	(265,445)	(242,462)
Opening Net Fixed Asset (2)	470,461	455,110	442,985	438,391	433,844	423,588	415,914
Less: Contribution in Aid of Construction	(54,391)	(53,325)	(52,196)	(51,656)	(45,014)	(39,445)	(31,537)
Closing Net Fixed Asset (3)	416,070	401,785	390,789	386,735	388,830	384,143	384,376
Average Fixed Asset (Rate Base)							
Opening Fixed Asset	401,785	390,789	386,735	388,830	384,143	384,376	387,718
Closing Fixed Asset (4)	416,070	401,785	390,789	386,735	388,830	384,143	384,376
	817,855	792,574	777,525	775,565	772,972	768,519	772,094
Average Fixed Asset (Rate Base) (5)	408,928	396,287	388,762	387,782	386,486	384,260	386,047

Note (1) - Adjustments includes disposals, retirements etc.

(2) - Closing Asset value at Cost less Closing Accumulated Depreciation.

(3) - Opening Net Fixed Asset less Contribution in Aid of Construction

(4) - Opening Fixed Asset plus Closing Fixed Asset divide by 2

(5) - This Schedule Excludes CIP, which is not eligible for Rate Base

	A	B	D	E	F
2	ENERSOURCE HYDRO MISSISSAUGA				
3	2008 BUDGET				
4	CAPITAL EXPENDITURES				
5					
6					
7					
8					
9	Note: all amounts in \$000'S				
11			2007	2007	2007
12	CATEGORY		Bridge Year	Bridge Year	Bridge Year
13			Forecast	Forecast October - December	Actual January - September
14	System Capacity - Growth Driven Investment:				
15		Subtransmission/Distribution Construction	5,850	1,524	4,326
16		Substation Construction	2,875	169	2,706
17		Total Growth Driven Investment	8,725	1,693	7,032
19	System Maintenance - Reliability Driven Investment:				
20		Subdivision Rebuilds	5,950	1,741	4,209
21		O / H Distribution Upgrades	2,525	94	2,431
22		U / G Distribution Maintenance	2,125	675	1,450
23		Transformer Replacement	600	99	501
24		Protection and Control Upgrades (SCADA)	1,370	854	516
25		Total Reliability Driven Investment	12,570	3,463	9,107
27		Total System Expansion Investment	21,295	5,156	16,139
29	System Expansion & Upgrades - Customer Driven Investment:				
30		New Industrial/Commercial Customer Services	4,000	165	3,835
31		New Subdivisions	2,500	1,858	642
32		Road Projects	750	15	735
33		Metering Equipment	1,954	1,620	334
34		Total Customer Driven Investment	9,204	3,658	5,546
36	Non-System Requirements - Regulatory Driven Investment:				
37		Conservation & Demand (3rd Tranche)	613	418	195
38		Wholesale Metering	772	772	-
40		Total Regulatory Driven Investment	1,385	1,190	195
42	Non-System Requirements - Internally Driven Investment:				
43		CIS	4,000	1,499	2,501
44		Rolling Stock	1,862	1,268	593
45		Major Tools	150	64	86
46		Information Technology	1,087	959	128
47		Engineering and Asset Systems	2,395	1,220	1,175
48		Grounds and Buildings (Capital Maintenance)	2,110	1,577	533
49		Grounds and Buildings (Land & Bldg)	-	-	
51	Information Systems and Facilities Total		11,604	6,586	5,018
53	TOTAL CAPITAL EXPENDITURES		43,488	16,590	26,898

ENERSOURCE HYDRO MISSISSAUGA

2008 BUDGET

CAPITAL EXPENDITURES

Enersource Hydro Mississauga Inc.

EB-2007-0706

2008 Electricity Distribution Rates Application

Filed: August 22, 2007

Exhibit C

Schedule 3

Tab xxx

Note: all amounts in \$000'S

CATEGORY	2008 CIP	2008 Fixed Asset Additions	2008 Test Year	2007 CIP	2007 Fixed Asset Additions	2007 Bridge Year	2006 CIP	2006 Fixed Asset Additions	2006 Actual
System Capacity - Growth Driven Investment:									
Subtransmission/Distribution Construction	560	5,850	5,850	560	5,850	5,850	2042	4102	4,810
Substation Construction	670	3,425	3,425	670	2,875	2,875	1298	3747	3,311
Total Growth Driven Investment	1,230	9,275	9,275	1,230	8,725	8,725	3340	7849	8,121
System Maintenance - Reliability Driven Investment:									
Subdivision Rebuilds	2,153	6,100	6,100	2,153	5,950	5,950	2153	3218	4,292
O / H Distribution Upgrades	129	2,600	2,600	129	2,525	2,525	517	3979	2,985
Contribution In Aid of Construction	-	3,750			4,000	-			
U / G Distribution Maintenance	142	2,200	2,200	142	2,125	2,125	142	3132	2,303
Construction in Progress Capitalised	-	-			3,281	-			
Transformer Replacement	11	650	650	11	600	600	17	932	887
Protection and Control Upgrades (SCADA)	528	1,400	1,400	528	1,370	1,370	603	1901	1,551
Total Reliability Driven Investment	2,963	16,700	12,950	2,963	19,851	12,570	3432	13163	12,018
Total System Expansion Investment	4,193	25,975	22,225	4,193	28,576	21,295	6772	21012	20,139
System Expansion & Upgrades - Customer Driven Investment:									
New Industrial/Commercial Customer Services	533	4,200	4,200	533	4,000	4,000	569	4774	4,526
New Subdivisions	140	2,575	2,575	140	2,500	2,500	140	2245	2,385
Road Projects	23	750	750	23	750	750	79	478	505
Metering Equipment	61	1,863	1,863	61	1,954	1,954	61	1194	1,255
Total Customer Driven Investment	757	9,388	9,388	757	9,204	9,204	849	8691	8,670
Non-System Requirements - Regulatory Driven Investment:									
Conservation & Demand (3rd Tranche)	203	-	-	203	613	613	814	1948	1,874
Wholesale Metering	-	145	145	-	772	772			
Total Regulatory Driven Investment	203	145	145	203	1,385	1,385	814	1948	1,874
Non-System Requirements - Internally Driven Investment:									
CIS	-	7,914	3,914	4,000	-	4,000			
Rolling Stock	-	1,858	1,858	-	1,862	1,862		1623	1,623
Major Tools	-	150	150	-	150	150		143	143
Information Technology	29	720	720	29	1,087	1,087	29	1016	1,044
Engineering and Asset Systems	-	1,545	1,545	-	2,395	2,395		2035	2,035
Grounds and Buildings (Capital Maintenance)		2,150	2,150		2,110	2,110		990	990
Grounds and Buildings (Land & Bldg)	-	2,500	2,500	-	-	-			-
Information Systems and Facilities Total	29	16,836	12,836	4,029	7,604	11,604	29	5806	5,834
TOTAL CAPITAL EXPENDITURES	5,182	52,345	44,595	9182	46,769	43,488	8464	37457	36,517

ENERSOURCE HYDRO MISSISSAUGA
2008 CAPITAL BUDGET PROJECT PROPOSAL

PROJECT: ROLLING STOCK	PROJECT NUMBER:	C0584
LOCATION: 3240 MAVIS RD.	FUNDS PROVIDED BY:	\$ 1,857,600
TYPE: ROLLING STOCK	BOARD	
	OTHERS	
DATE PREPARED: May 12, 2007	TOTAL ESTIMATED COSTS	\$1,857,600

This proposal covers replacements to our rolling stock

<u>Type</u>	<u>Unit #</u>	<u>Year</u>	<u>Replacement Cycle</u>	<u>Year to Replace</u>	<u>Cost (\$)</u>
Car	2105	2005	3	2008	\$47,200
Car	2205	2005	3	2008	\$47,200
Car	2305	2005	3	2008	\$47,200
Car	3300	2000	5	2005	\$25,000
Car	3400	2000	5	2005	\$25,000
Bucket Truck	20297	1997	10	2007	\$200,000
Bucket Truck	20495	1995	12	2007	\$372,400
Bucket Truck	20697	1997	10	2007	\$200,000
Bucket Truck	21099	1999	9	2008	\$190,000
Van	31199	1999	7	2006	\$120,000
Pickup Truck	41603	2003	5	2008	\$35,000
Pickup Truck	42103	2003	5	2008	\$35,000
Pickup Truck	42703	2003	5	2008	\$35,000
Pickup Truck	42903	2003	5	2008	\$35,000
Pickup Truck	45300	2000	7	2007	\$40,000
Mini Van	51601	2001	5	2006	\$25,000
Mini Van	51701	2001	5	2006	\$55,000
Mini Van	51801	2001	5	2006	\$55,000
Van	53900	2000	7	2007	\$55,000
Sweeper	90794	1993	15	2008	\$70,000
Off Road access vehicle	New		5	2008	\$15,000
Kubota Trailer	92295	1995	13	2008	\$12,000
Cargo Trailer	94188	1988	12	2000	\$19,000
Air Compressor	97390	1990	18	2008	\$20,000
Air Compressor	97490		18	2008	\$20,000
Hydraulic Tools & Service Equipment	2105				\$57,600

Estimated Annual Expenditure

2008					2009	2010	Future
Q1	Q2	Q3	Q4	Total			
\$150,000	\$150,000	\$300,000	\$1,257,600	\$1,857,600			

Prepared

Accepted

Approved

ENERSOURCE HYDRO MISSISSAUGA
2007 CAPITAL BUDGET PROJECT PROPOSAL

PROJECT: ROLLING STOCK	PROJECT NUMBER: C0584	
LOCATION: 3240 MAVIS RD.	FUNDS PROVIDED BY: BOARD	\$ 1,861,800
TYPE: ROLLING STOCK	OTHERS	
DATE PREPARED: August 31, 2006	TOTAL ESTIMATED COSTS	\$1,861,800

This proposal covers replacements to our rolling stock in 2007.

<u>Type</u>	<u>Unit #</u>	<u>Year</u>	<u>Replacement Cycle</u>	<u>Year to Replace</u>	<u>Cost (\$)</u>
Car	00705	2004	3	2007	\$ 53,100
Car	01604	2004	3	2007	\$ 59,000
Car	01704	2004	3	2007	\$ 53,100
Car	01805	2004	3	2007	\$ 47,200
Car	02004	2004	3	2007	\$ 47,200
Car	01904	2004	3	2007	\$ 47,200
Bucket Truck	20195	1995	10	2007	\$ 180,000
Bucket Truck	23491	1991	12	2007	\$ 400,000
Dump Truck	404-97	1997	10	2007	\$ 45,000
Van	300-99	1999	7	2007	\$ 120,000
Van	307-99	1999	7	2007	\$ 120,000
Van	308-99	1999	7	2007	\$ 120,000
Van	309-99	1999	7	2007	\$ 120,000
Van	320-97	1997	7	2007	\$ 120,000
Pickup Truck 4 x 4	44000	2000	7	2007	\$ 40,000
Pickup Truck	449-97	2000	7	2007	\$ 30,000
Pickup Truck	453-00	2000	7	2007	\$ 40,000
Pickup Truck	New		7	2007	\$ 50,000
Mini Van	50701	2001	5	2007	\$ 25,000
Mini Van	51297	1997	5	2002	\$ 35,000
Sports Utility Vehicle	51500	2000	7	2007	\$ 40,000
Backhole Trailer	926-97	1997	10	2007	\$ 20,000
Hydraulic Tools & Equipment					\$ 50,000

TOTAL - ROLLING STOCK \$1,861,800

Estimated Annual Expenditure

2007					2007	2008	Future
Q1	Q2	Q3	Q4	Total			
\$150,000	\$150,000	\$300,000	\$1,261,800	\$1,861,800			

Prepared _____ Accepted _____ Approved _____

ENERSOURCE HYDRO MISSISSAUGA
2006 CAPITAL BUDGET PROJECT PROPOSAL

PROJECT: ROLLING STOCK	PROJECT NUMBER: C0584	
LOCATION: 3240 MAVIS RD.	FUNDS PROVIDED BY: BOARD	\$ 1,725,000
TYPE: ROLLING STOCK	OTHERS	
DATE PREPARED: September 9, 2005	TOTAL ESTIMATED COSTS	\$1,725,000

This proposal covers replacements to our rolling stock in 2005.

<u>Type</u>	<u>Unit #</u>	<u>Year</u>	<u>Replacement Cycle</u>	<u>Year to Replace</u>	<u>Cost (\$)</u>
4 Door Sedan	005-99	1999	4	2003	\$ 25,000
4 Door Sedan	006-99	1999	4	2003	\$ 25,000
4 Door Sedan	033-00	2000	4	2004	\$ 25,000
4 Door Sedan	034-00	2000	4	2004	\$ 25,000
Flat Bed Material	100-95	1995	10	2005	\$ 200,000
Derrick	112-90	1990	10	2000	\$ 180,000
Bucket Truck	201-95	1995	10	2005	\$ 180,000
Dump Truck	431-96	1996	10	2006	\$ 45,000
Dump Truck	432-96	1996	10	2006	\$ 45,000
Van	310-99	1999	7	2006	\$ 120,000
Van	311-99	1999	7	2006	\$ 120,000
Van	322-98	1998	7	2005	\$ 120,000
Van	323-98	1998	7	2005	\$ 120,000
Van	326-99	1999	7	2006	\$ 120,000
Pickup Truck	403-97	1997	7	2004	\$ 40,000
Pickup Truck	411-99	1999	7	2006	\$ 35,000
Pickup Truck	419-94	1994	5	1999	\$ 25,000
Pickup Truck	420-94	1994	5	1999	\$ 50,000
Panel Van	510-96	1996	5	2001	\$ 30,000
Panel Van	514-00	2000	5	2005	\$ 30,000
Mini Van	516-01	2001	5	2006	\$ 25,000
Mini Van	517-01	2001	5	2006	\$ 25,000
Mini Van	518-01	2001	5	2006	\$ 25,000
Mini Van	519-01	2001	5	2006	\$ 25,000
Tandem Axle C	919-94	1994	12	2006	\$ 15,000
Hydraulic Tools & Equipment					\$ 50,000

Total Cost for the above proposal is \$ 1,725,000

Estimated Annual Expenditure

2006					2007	2008	Future
Q1	Q2	Q3	Q4	Total			
\$150,000	\$150,000	\$300,000	\$1,125,000	\$1,725,000			

Prepared

Accepted

Approved

2005 CAPITAL BUDGET PROJECT PROPOSAL

PROJECT: ROLLING STOCK

PROJECT NUMBER:

C9584

LOCATION: 3240 MAVIS RD.

FUNDS PROVIDED BY:

BOARD

\$1,766,000

TYPE: ROLLING STOCK

OTHERS

DATE PREPARED: September 10, 2004

TOTAL ESTIMATED COSTS

\$1,766,000

This proposal covers replacements to our rolling stock in 2005.

<u>Type</u>	<u>Unit #</u>	<u>Year</u>	<u>Replacement Cycle</u>	<u>Year to Replace</u>	<u>Cost (\$)</u>
Car	016-01	2001	3	2004	\$54,000
Car	018-01	2001	3	2004	\$44,000
Car	021-02	2002	3	2005	\$44,000
Car	022-02	2002	3	2005	\$44,000
Car	023-02	2002	3	2005	\$44,000
Bucket	200-94	1994	10	2004	\$125,000
Bucket	228-88	1988	10	1998	\$322,000
Work Van	313-95	1995	7	2002	\$109,000
Work Van	318-96	1996	7	2003	\$109,000
Work Van	320-97	1997	7	2004	\$109,000
Work Van	321-97	1997	7	2004	\$109,000
Work Van	324-98	1998	7	2005	\$109,000
Work Van	325-98	1998	7	2005	\$109,000
Pick-up	403-97	1997	7	2004	\$40,000
Pick-up	428-96	1995	5	2000	\$25,000
Pick-up	430-95	1995	5	2000	\$35,000
Mini-Van	504-95	1995	5	2000	\$25,000
Mini-Van	508-95	1995	5	2000	\$25,000
Mini-Van	511-97	1997	5	2002	\$25,000
Panel Van	514-00	2000	5	2005	\$30,000
Panel Van	537-98	1998	5	2003	\$45,000
Panel Van	538-98	1998	5	2003	\$45,000
Cargo Trailer	902-93	1993	10	2003	\$15,000
Cargo Trailer	941-88	1988	12	2000	\$15,000
Cargo Trailer	942-88	1988	12	2000	\$15,000
Cargo Trailer	953-89	1989	12	2001	\$15,000
Cargo Trailer	954-88	1988	12	2000	\$15,000
Cargo Trailer	962-90	1990	12	2002	\$15,000
Hydraulic Tools & Equipment					\$50,000

Total cost for the above proposal is \$1,766,000

Estimated Annual Expenditure

2005					2006	2007	Future
Q1	Q2	Q3	Q4	Total			
\$150,000	\$150,000	\$300,000	\$1,166,000	\$1,766,000			

Prepared

Accepted

Approved

Answers to SEC question 43

Items Paid to/Received from affiliates: (1) Management Fees: paid to Enersource Corporation

	<u>Driver (B)</u>	<u>'07 & '08 Alloc %</u>	<u>2008 Test yr.</u>	<u>2007 Bridge yr.</u>	<u>2006 Alloc %</u>	<u>2006 Actual</u>
Enersource Hydro Mississauga:						
Corporate Governance	Time Estimate	90.00%	189	270	90.00%	391
Executive Management and Communications	Time Estimate	90.00%	2,012	2,195	90.00%	2,000
Safety	Time Estimate	90.00%	654	600	90.00%	831
Human Resources	Headcount	92.00%	1,008	944	88.00%	769
Finance	Time Estimate	80.00%	3,050	3,150	80.00%	2,486
Purchasing	Time Estimate	90.00%	138	146	90.00%	135
Legal	Time Estimate	30.00%	96	96	30.00%	52
Enersource Hydro Charges	Historical	85.00%	705	569	85.00%	674
Capital Taxes	Historical	85.00%	20	20	85.00%	15
Other Expense/Financial Income/Other Income	Historical	85.00%	371	394	85.00%	449
Total Management Fee			<u>\$ 8,243 (A)</u>	<u>\$ 8,383</u>	(C)	<u>\$ 7,802 (C)</u>

Enersource Mississauga Hydro Inc. (Enersource)
2008 Electricity Rate Application
Board File No. EB-2007-0706
VECC's Interrogatories

Vulnerable Energy Consumers Coalition Interrogatories'

Interrogatory

Question #1 Reference: i) Exhibit A/Schedule 7/Tab 1/page 1

a) Please provide copies of all Decisions and Orders issued by the OEB since January 1, 2005 regarding Enersource's rates and/or terms and conditions of service.

Response

The requested Decisions and Orders are attached.

Interrogatory

Question #2 Reference: i) Exhibit A/Schedule 8/Tab 2/page 4, lines 9-15 ii)

Exhibit A/Schedule 8/Tab 4/page 1

a) Does the 600 amps performance criterion apply to all feeders, subtransmission and distribution? If not, how does the criterion vary by

voltage and why? If yes, why does the same criterion apply to all?

b) Do Enersource's neighbouring LDCs use a similar performance criterion?

If not, what criterion do they use?

c) Do Enersource's neighbouring LDCs also try (in practice) not to load feeders beyond 300 amps?

d) What is Enersource's performance criterion and preferred practice with respect to the loading of its municipal substations? How does this compare with the policies and practices of its neighbouring LDCs?

Response

- a) Yes. The performance criterion applies to all feeders, it is the manufacturer's rated capacity.
- b) Enersource does not have any information about the performance criterion relied on by neighbouring distributors.
- c) To the best of Enersource's knowledge, LDCs neighbouring Enersource would not typically load their feeders beyond 300 amps either, doing so would negatively impact reliability.
- d) The loading on Municipal Stations varies depending on a number of factors. Enersource has 2006 observed load duration curves for Municipal Stations.

Interrogatory

Question #3 Reference: i) Exhibit A/Schedule 8/Tab 5/page 1

a) What is the amount of energy associated with each of the four load transfer circumstances set out on page 1?

Response

The requested information is provided in the table below.

Load Transfers in 2006 - all units in kWh

Energy delivered by Enersource		Energy received into Enersource service area	
Delivering LDC	Energy delivered	Receiving LDC	Energy delivered
Oakville	271,533	Milton	1,365,679
Brampton	79,359	Brampton	957,997

Interrogatory

Question #4 Reference: i) Exhibit A/Schedule 10/Tab 1

a) The “organization chart” suggests that Enersource Hydro Mississauga is 100% owned by Enersource Corporation. Please confirm whether or not this is the case. If not please provide a corrected “chart”.

Response

Yes, Enersource Hydro Mississauga Inc. is 100% owned by Enersource Corporation.

Question #5 Reference: i) Exhibit A/Schedule 12.1

a) Please provide the December 2005 and December 2006 balances for each of Enersource's Regulatory Asset and Liability accounts. Please provide a schedule setting out, for each account, the 2006:

- Interest charges/credits to the account
- The amount refunded/recovered from customers
- Any new costs or credits posted to the account for the year.

b) Who received dividend payments In 2005 and 2006 (see page 2 of Financial Statements)? What is the shareholders' policy as to under what circumstances and in what amounts dividends will be declared each year?

Response

a. Please see response to Board Staff #44.

b. Enersource Corporation received dividends in 2005 and 2006. The corporation's dividend policy is to distribute 60% of prior year net income unless otherwise recommended by management (eg., based on solvency, credit rating, cash or investment requirements) and approved by the Audit Committee and the Board of Directors.

Interrogatory

Question #6 Reference: i) Exhibit A/Schedule 12/Tab 3

Please provide Enersource's overhead capitalization policy.

Response

Overhead is capitalized through recoveries and burdens. Enersource follows GAAP principles in its capitalization of indirect overhead through recoveries. Please see Exhibit D/Schedule 1/Tab 11.

Interrogatory

Question #7 Reference: i) Exhibit A/Schedule 12/Tab 4, page 2 ii) Exhibit E/Schedule 1/Tab 1, page 3

a) What account for the difference between the interest expense reported in reference (ii) of \$18.675 M and that reported in reference (i) of \$19.529 M for 2008?

Response

The \$19.529M is deemed interest expense and used to determine the revenue requirement. The \$18.675M is the forecast interest expense.

Interrogatory

Question #8 Reference: a) Exhibit A/Schedule 12/Tab 7

a) Please provide a similar schedule that sets out Enersource's Statement of Income for 2006, 2007 and 2008 in a format consistent with the USoA.

Response

Please see attached spreadsheet. (Also please refer to Enersource's pro forma financial statements in Exhibit A/Schedule 12/Tab 4).

ENERSOURCE HYDRO MISSISSAUGA INC.

Statement of Income

(in thousands of dollars)

	Test 2008	Bridge 2007	Actual 2006
NET SALES REVENUE			
Sales of Electricity	\$ (601,101)	\$ (564,470)	\$ (557,271)
Power Supply Expenses (Working Capital)	\$ 601,101	\$ 564,470	\$ 557,271
	\$ -	\$ -	\$ -
SALES OF ELECTRICITY NET OF COST OF POWER	-	-	-
DISTRIBUTION REVENUE			
Distribution Services Revenue	\$ 117,426	\$ 113,699	\$ 111,263
Other Distribution Revenue*	\$ 2,814	\$ 2,816	\$ 2,863
TOTAL DISTRIBUTION REVENUE	\$ 120,240	\$ 116,515	\$ 114,126

OM&A EXPENSES (before PILS & Capital Taxes):

Operation (Working Capital)	\$ 17,279	\$ 16,468	\$ 14,395
Maintenance (Working Capital)	\$ 2,557	\$ 2,530	\$ 2,630
Billing and Collection (Working Capital)	\$ 5,286	\$ 5,103	\$ 4,311
Community Relations (Working Capital)	\$ -	\$ -	\$ -
Community Relations - CDM (Working Capital)	\$ -	\$ 2,600	\$ 1,906
Administrative and General Expenses (Working Capital)	\$ 14,431	\$ 12,394	\$ 9,001
Insurance Expense (Working Capital)	\$ -	\$ -	\$ -
Bad Debt Expense (Working Capital)	\$ 1,575	\$ 1,875	\$ 2,580
Advertising Expenses	\$ -	\$ -	\$ -
Charitable Contributions	\$ -	\$ -	\$ -
Other Distribution Expenses	\$ 949	\$ 918	\$ 639
Non- Distribution Expense / Revenue Reclass*			\$ 438

	\$	\$	\$
TOTAL OM&A EXPENSES	42,076	41,889	35,899
	\$	\$	\$
Taxes Other Than Income Taxes (Capital Taxes)	1,482	1,450	1,557
	\$	\$	\$
Amortization of Assets	34,357	32,007	30,275
	\$	\$	\$
Amortization of Regulatory Assets	(5,118)	6,129	7,144
	\$	\$	\$
TOTAL DISTRIBUTION EXPENSES (before PILs)	72,797	81,475	74,875
	\$	\$	\$
TOTAL OPERATING INCOME	47,443	35,040	39,251
	\$	\$	\$
Interest Income	2,049	2,507	2,764
Other Interest Expense	\$	\$	\$
	(19,529)	(19,187)	(18,595)
	\$	\$	\$
	(17,480)	(16,680)	(15,831)
Payments in lieu of corporate income taxes	11,768	8,130	10,119
	\$	\$	\$
Net income	18,195	10,230	13,301

* GTAA Interconnect Revenue & Expense are included to tie to financial statement

Interrogatory

Question #9 Reference: a) Exhibit A/Schedule 14/Tab 1, page 1 b) Exhibit A/Schedule 14/Tabs 5 & 6

a) Please indicate where in the Application the following items are accounted for:

- Revenues received from Enersource's affiliates for use of trucks and other vehicles**
- Revenues received from the provision of Information Technology Services to affiliates.**

b) Do the fees charged for services provided by Enersource to its affiliates (see page 171 of overall Application) include a mark-up for corporate overheads? If so, how is it determined? If not, why not?

c) Based on one of the services provided to affiliates, please provide an illustrative example of how Enersource determines the fees payable that sets out the various cost components included.

d) With respect to each of the services provided by Enersource Corporation to Enersource Hydro and their associated fees (see page 163 of the overall Application), please provide:

- A schedule that sets out the calculation of the 2006 fees based on HOLDCO's 2006 budget (i.e., show total budget and basis on which proportion chargeable to Enersource Hydro was established)**
- A schedule that sets of the actual costs incurred for 2006 by HOLDCO and the resulting adjustment in charges to Enersource Hydro**

Response

- a) Revenue received from Enersource's affiliates' use of trucks and other vehicle is included in the fleet recovery. Revenue received from the provision of Information Technology Services is included IT recoveries.
- b) The recoveries for services charged out to affiliates for Facilities and Information Systems usage are allocated on a Headcount basis and is cost based. The recovery for assets used by affiliates is allocated on a blend of Headcount and the allowed return authorized by the OEB.

c)

Answer to VECC question 9 C

	2008 Test Yr	2007 Bridge Yr
Information Systems costs to Enersource Hydro Mississauga	\$ 3,067	\$ 2,838
HEADCOUNT:		
Enersource Hydro Mississauga	323	317
Enersource Corporation	47	47
EHMS	20	15
	390	379
Information Systems Costs Recoveries Charged to Enersource Corporation	\$ 370	\$ 352
Information Systems Costs Recoveries Charged to EHMS	\$ 157	\$ 112

d) Please see attached schedule

Interrogatory

Question #10 Reference: i) Exhibit B/Schedule 1/Tab 1 ii) Exhibit A/Schedule 15/Tab 1.1, Appendix A iii) Exhibit B/Schedule 2/Tab 4 iv) Exhibit B/Schedule 2/Tab 5, page 2

a) Please reconcile the monthly charges reported in reference (ii) for each customer class with the monthly charges used in reference (iii) to determine revenues at existing rates (e.g., the residential monthly services charges do not match).

b) Does Enersource have any other standby customers other than Britannia and GTAA? If so, where is the associated standby charge revenue accounted for?

c) Please describe further the new payment mechanisms that Enersource has recently introduced (reference (iv)).

Response

a. The differences in the monthly charges reported in reference (ii) vs. (iii) are due to the Smart Meter charge of \$1.28 for all customer classes, except Streetlights and Flat Rate customers.

b. Enersource provides standby service to the following customers:

- Integrated Gas Recovery Services Inc.;
- Greater Toronto Airport Authority;
- Orenda; and
- TransAlta.

The standby service revenue recovered from Orenda and TransAlta is included in the revenues recovered from their respective customer class.

c. See response to SEC # 20.

Interrogatory

Question #11 Reference:

- i) Exhibit B/Schedule 3/Tab 1**
- ii) Exhibit B/Schedule 3/Tab 2**
- iii) Exhibit H/Schedule 3/Tab 1**

- a) Please explain why the median temperature day (as opposed to the average) was selected to establish the normal weather scenario (see reference (i), page 1).**
- b) Please provide a table similar to that on page 5 of reference (ii) but based on weather corrected energy use.**
- c) Reference (i) only discusses how weather corrected energy use is established. However, Figure 3 on page 8 of reference (ii) appears to suggest that Enersource also establishes weather corrected peak use. Please describe how peak demands are weather normalized.**
- d) Please provide a table similar to that on page 8 of reference (ii) but based on weather corrected peaks.**
- e) Please provide details (e.g.,) regarding the MetrixND load forecasting methodology (reference (ii), page 13) including:**
 - Whether there are separate models for demand and energy.**
 - The specific parameters included in the model and their statistical significance.**
 - If there are other Ontario LDCs that also use this model.**
- f) In a schedule please set out:**
 - The 2008 assumptions for the economic driver underlying the short term load forecast for 2008.**
 - The 1998 through 2006 values for the same parameters**
 - The current 2007 projected values for the same parameters.**
- g) Did the load forecasting model used to forecast 2008 demand and energy usage utilize 2005 and/or 2006 load data?**
- h) If the response to (g) is yes, then is it reasonable to assume that the 2008 forecasts for demand and energy provided by the model include some C&DM effect? If not, why not?**
- i) Please describe how the overall forecast for Enersource's total energy requirements and peak demand is translated into a forecast of number of the customers, energy use and billing demand for each customer class.**

Response

- a. The weather normalization process utilized the median temperature day in order to provide a specific date for a 'normal weather day'. This specific date was then indexed to create a 'normal temperature scenario' and 'normal dew point scenario'. In addition, the median temperature day was selected from a list of similar day of the year ranked by**

the daily mean (arithmetic average) temperature. Thus, both the median and mean methods were utilized in developing the normal weather scenario.

b. Weather corrected values can be found in the updated Appendix A of 'ExB Sch3 Tab2 _ Appendix A_ Updated.xls'

c. The Short Term Load Forecast has two forecast models; energy consumption model and peak demand forecast model. Similar to weather correcting energy consumption, the process for correcting actual peak demand for weather is also completed in three steps:

- 1) A Peak Demand model is created based on actual peak demand data, actual weather conditions, actual economic drivers and calendar.
- 2) Normal Weather Scenario is created based on 35 years of weather data. The same normal weather scenario is used for energy consumption and peak demand forecasting.
- 3) The Peak Demand Model is run on the normal weather condition, actual historic economic drivers and calendar.

d. Weather corrected values can be found in the updated Appendix A of 'ExB Sch3 Tab2 _ Appendix A_ Updated.xls'

e.

- The Short Term Load Forecast has two forecast models; energy consumption model and peak demand forecast model.
- In the Short Term Load Forecast, the energy consumption model and peak demand model were forged based on actual data from January 1996 to April 30, 2007 based on actual System Load, Econometric data (Population, Employment, Housing) and Calendar Data. The actual and forecasted econometric data for energy consumption drivers and peak demand drivers are located in 'Economic Drivers used for Load Forecast.xls'. The Statistical significance is provided in 'Short Term Load Forecasts Statistical Parameters.xls' worksheet.
- Enersource is not aware of other Ontario LDCs utilizing this model. The IESO and OPG are two known entities utilizing MetrixND with similar approaches to load forecasting.

f. The actual and forecasted econometric data for energy consumption drivers and peak demand drivers are located in attachment, 'Economic Drivers used for Load Forecast.xls'

g. Yes.

h. Yes. The recent focus on CDM Activities is over and above prior CDM activities.

i. Estimated energy purchases in kWh per Short Term Load Forecast Exhibit B / Schedule 3 / Tab 2 are allocated to each customer class based on the three year actual average for each respective customer class. Energy related to residential, small commercial and general service class less than 50 kW are then calculated. For the general service classes greater than 50kW, large users, and street lighting a three year actual load factor are used to convert the kWh to KW for billing demand. The resultant forecast was adjusted for projected CDM programs in the 2008 Test Year. For specific details see Exhibit B / Schedule 2/ Tab 2, 2.1, and 3.

In forecasting the number of customers, we use past trending data as well as forecasts from the City of Mississauga Economic Planning Dept see Exhibit B / Schedule 2 / Tab 1 for specific details. (See response to CCC # 3 & 4 and OEB # 17).

Interrogatory

Question #12 Reference: i) Exhibit B/Schedule 2/Tab 2.1 ii) Exhibit D/Schedule 2/Tab 10.2

a) Please provide a schedule that breaks down the contribution of C&DM included in the 2008 load forecast (reference (i)) by program, per reference (ii).

Response

[Please refer to the response to Board staff question #20.](#)

Interrogatory

Question #13 Reference: i) Exhibit B/Schedule 2/Tab 2, page 1

ii) Exhibit D/Schedule 1/Tab 9.2

iii) Exhibit B/Schedule 3/Tab 2, page 5

a) Please reconcile the difference between the 2006 energy deliveries in reference (i) and the 2006 Retail kWh in reference (ii).

b) Please reconcile the 2006 Wholesale kWh reported in reference (ii) with the 2006 actual Total Energy reported in reference (iii).

Response

a. In reference (i), this chart represents EHM's actual energy consumption which excludes losses but includes embedded generation. In reference (ii) this analysis on losses reviews energy purchases from the IESO only which excludes embedded generation. The differences between these two reports are due to losses, embedded generation and timing of IESO purchases versus EHM's actual billings.

b. In reference (iii), this chart represents EHM's actual energy consumption which includes losses and embedded generation. In reference (ii) (as above) this analysis on losses reviews energy purchases from the IESO only which excludes embedded generation. The differences between these two reports are due to embedded generation and timing of IESO purchases versus EHM's actual billings.

Interrogatory

Question #14 Reference: i) Exhibit C/Schedule 1/Tab 1 ii) Exhibit C/Schedule 3/Tab 2

Preamble: The last time Enersource's rates were based on a "cost of service" type approach was for 2006. In that process, rate base was determined by making various adjustments to 2004 year end actual values. Enersource is currently seeking approval for its 2008 rate base.

a) Please provide a continuity schedule for Enersource's Net Plant, Property and Equipment similar to reference (ii) but that:

• Starts as of December 31, 2004.

• Also shows separately:

The capital expenditures during the year

The in-service asset additions during the year

Year end assets under construction (CWIP)

Response

FIXED ASSETS CONTINUITY SCHEDULE (000's)

	2008 <u>Test Year</u>	2007 <u>Bridge Year</u>	2006 <u>Historic Year</u>	2005 <u>Historic Year</u>	2004 <u>Historic Year</u>
<u>Property, Plant & Equipment</u>					
Opening Asset Value at Cost	820,103	778,434	751,820	724,575	689,033
Capital Expenditure - Additions	52,345	46,769	37,669	36,733	41,569
Adjustments (1)	(9,625)	(5,100)	(11,055)	(9,488)	(6,027)
Closing Asset Value at Cost	862,823	820,103	778,434	751,820	724,575
Opening Accumulated Depreciation	(364,994)	(335,449)	(313,429)	(290,731)	(265,445)
Depreciation Expense	(37,041)	(34,535)	(32,689)	(31,931)	(31,166)
Adjustments (1)	9,673	4,990	10,669	9,232	5,880
Closing Accumulated Depreciation	(392,362)	(364,994)	(335,449)	(313,429)	(290,731)
Opening Net Fixed Asset (2)	470,461	455,110	442,985	438,391	433,844
Less: Contribution in Aid of Construction	(54,391)	(53,325)	(52,196)	(51,656)	(45,014)
Closing Net Fixed Asset (3)	416,070	401,785	390,789	386,735	388,830
Average Fixed Asset (Rate Base)					
Opening Fixed Asset	401,785	390,789	386,735	388,830	384,143
Closing Fixed Asset (4)	416,070	401,785	390,789	386,735	388,830
	817,855	792,574	777,525	775,565	772,972
Average Fixed Asset (Rate Base) (5)	408,928	396,287	388,762	387,782	386,486
Construction Work In Progress (See Note 5 Below)	5,182	9,182	8,464	7,312	5,014

Note (1) - Adjustments includes disposals, retirements
etc.

- (2) - Closing Asset value at Cost less Closing Accumulated Depreciation.
- (3) - Opening Net Fixed Asset less Contribution in Aid of Construction
- (4) - Opening Fixed Asset plus Closing Fixed Asset divide by 2
- (5) - This Schedule Excludes CIP, which is not eligible for Rate Base

Interrogatory

Question #15 Reference: i) Exhibit C/Schedule 1/Tab 1, page 2 ii) Exhibit C1/Schedule 3/Tab 5

a) Please explain why Enersource has not performed a lead/lag study in order to justify its working cash requirements for 2008.

b) Working capital studies performed by other Ontario LDCs have resulted in requirements that are less than 15% of controllable costs plus the cost of power. For example, in its 2006 Rate Application, Hydro One Networks' Lead/Lag study resulted in a working capital allowance equal to 11.6% of controllable costs plus the cost of power (see Exhibit D1/Tab 1/Schedule 4 of the Application). Please comment on the reasonableness of using a similar value for Enersource.

Response

a) Enersource has not performed a Lead Lag study because it considers the Board's 15% of controllable costs plus the cost of power a reasonable estimate of Enersource's working cash requirements. Enersource conducted an informal assessment of its monthly working cash requirements and established the following low and high estimates of its Leading uses of cash:

	Low	High
• Cost of power	35M	72M
• GST	3M	6M
• PILs	1M	1.5M
• Payroll	2.5M	1.75M
• Payments to contractors	0.5M	1.5M
• Prepaid Expenses	0.25M	0.5M
• Dividends	0.6M	0.75M
• Other Regulated Charges	9M	18M
• Total	51.85M	102.00M

Enersource's claimed Working Cash Allowance for 2008 is \$96.5 M and is in the computed range.

b) Enersource is not in a position to comment on or discuss the reasonableness of using the results of other distributors Lead Lag studies.

Interrogatory

Question #16 Reference: i) Exhibit C/Schedule 1/Tab 2, page 6

a) The Application indicates that loads and number of customers have grown significantly in the last three years and are expected to continue to do so. If there are tables in the Application that contrast recent (e.g., 2003-2006) customer and load growth with expected (2007 and 2008) growth that illustrates this expectation please provide the appropriate references. If not, please provide the appropriate schedules.

b) To what extent are the anticipated new customers expected to lead to “system expansion” that could trigger a potential capital contribution?

Response

a. Forecasted growth in customers and load is expected to reflect past growth. Please refer to the Exhibit B / Schedule 2 where forecasted charge parameters are derived and to the Short Term Load Forecast at Exhibit B / Schedule 3 / Tab 1. Also please see the responses to SEC interrogatory #1, Board Staff interrogatory #16 and CCC interrogatories #4, #8 and #9.

b. Any potential capital contribution is the result of an economic evaluation that is computed in accordance with the Distribution System Code and when the project is completed. Enersource Hydro records the Contribution in Aid of Construction as an offset to the fixed assets.

Interrogatory

Question #17 Reference: i) Exhibit C/Schedule 1/Tab 3, page 3 ii) Exhibit C/Schedule 5/Tab 1, pages 62-68

a) Reference (i) indicates that one of Enersource's significant IT projects is implementation of an "Integrated Operating Model". However, there is no budget or business case provided in reference (ii) for this project. Please provide a more detailed description of the project, the annual capital expenditures and the business case supporting the initiative.

Response

[Please refer to the response to SEC interrogatory # 28.](#)

Interrogatory

Question #18 Reference:

- i) Exhibit C/Schedule 4/Tab 1**
- ii) Exhibit C/Schedule 3/Tab 4**
- iii) Exhibit C/Schedule 5/Tab 1**

a) Please provide the business cases for each of the 2007 projects set out in reference (i) with a cost of \$250,000 or more.

b) Please provide a breakdown of the 2008 capital expenditures set out in reference (ii) into individual projects, similar to that done for 2007 in Appendix A of reference (i). Please identify the in-service date for each project.

c) Please provide the business cases for all capital projects in 2008 with a total cost of \$250,000 which have not been already addressed in reference (iii).

Response

a. Asset investment is generally driven by system requirements (eg., to meet load), customer requirements or reliability requirements and not by ROI. Individual business cases for 2007 were not created as Enersource follows its capital budgeting practices, which begins with the completion of the System Capacity Report. Enersource's 2007 budget was then approved by management, executives, and Board of Directors.

b. Please see the response to SEC interrogatory #27 and to Board staff interrogatory #9.

c. Please see the response to part a).

Interrogatory

Question #19 Reference: i) Exhibit D/Schedule 2/Tab 5 and Tab 6 ii) Exhibit A/Schedule 11/Tab 1

- a) Please indicate how the 18 new positions in 2008 are distributed across the business units set out in reference (ii) – Head Count summary.**
- b) Please explain what gave rise to the need in 2008 for the new positions in each of these business units**
- c) Please indicate how the 12 new positions in 2007 were distributed across the business units in reference (ii).**
- d) Please explain what gave rise to the need in 2007 for the new positions in each of these business units.**

Response

[Please see the response to Board Staff interrogatory #31.](#)

Interrogatory

Question #20 Reference: i) Exhibit D/Schedule 1/Tab 11

- a) Please breakdown the \$8.243 M in Management Fees according to the service categories (i.e., page 163 of the overall Application).**
- b) Please provide a schedule that sets out the calculation of the 2008 fees by category based on HOLDCO's 2008 budget (i.e., show total budget and basis on which proportion chargeable to Enersource Hydro was established).**

Response

- a) & b) [Please see the response to Board Staff interrogatory #25.](#)**

Interrogatory

Question #21 Reference: i) Exhibit D/Schedule 2/Tab 2 ii) Exhibit A/Schedule 11/Tab 1

a) Please breakdown the 2006, 2007 and 2008 Administration costs (per reference (i)) as between the various underlying organizational units set out in reference (ii).

Response

Please note that the Organizational Chart and the Business Units referenced in the interrogatory are relied on for independent purposes. The financial controls applied to business units are not aligned with the reporting and staff controls depicted through the Organizational Chart.

Interrogatory

Question #22 Reference: i) Exhibit D/Schedule 2/Tab 1

a) Was any OM&A expense capitalized as overheads in 2006, 2007 or 2008?

If not, why not?

b) If the response to (a) is yes, please indicate the OM&A amounts that were capitalized as overheads in 2006, 2007 and 2008 and provide schedules setting out how the amounts for each were determined.

Response

a. OM&A expenses in 2006, 2007 and 2008 were or will be capitalized and allocated to customer projects. Exhibit D, Schedule 1/Tab 11,

b. The amount capitalized and allocated to customer projects for each year is listed below.

Description	2006	2007	2008
Recoveries	- 8,140	- 8,174	- 7,485

Interrogatory

Question #23 Reference: i) Exhibit D/Schedule 1/Tab 6, pages 1&2
a) The other expenses discussed appear to account for less than \$2.5 M of the \$3.534 M projected for 2008. Please provide a schedule showing a breakdown of the total other expenses for 2006 through 2008.

Response

Below is a table illustrating the breakdown of the total other expenses for 2008.

TOTAL OTHER EXPENSES	2006	2007	2008
ESA FEES ASSESSED	\$81	\$85	\$88
OEB FIXED COSTS ASSESSED	\$509	\$780	\$840
INCENTIVE PLAN	\$1,159	\$1,174	\$1,280
RETAIL TRANSACTION HUB	\$130	\$323	\$329
REGULATORY COSTS	\$17	\$90	\$270
ENVIRONMENTAL REHABILITATION COSTS	\$311	\$200	\$300
FIBER CHARGES	<u>\$180</u>	<u>\$180</u>	<u>\$180</u>
Exhibit D/Schedule 1/Tab 6/Page 2 of 2	\$2,387	\$2,832	\$3,287
<u>Other Costs</u>			
ANNUAL BOND RATING EXPENSES	\$44	\$97	\$94
POLE ATTACHMENTS	\$43	\$21	\$21
INVENTORY WRITE-OFF AND RESERVE	\$56	\$70	\$70
MISCELLANEOUS EXPENSE	\$47	\$355	\$62
Not Included in Exhibit D/Schedule 1/Tab 6/Page 2 of 2	<u>\$190</u>	<u>\$543</u>	<u>\$247</u>
Total	\$2,577	\$3,375	\$3,534

Interrogatory

Question #24 Reference: i) Exhibit D/Schedule 2/Tab 10.3

a) Please provide the detailed calculations supporting the Total Benefits calculated for each program. Please document the source and assumptions underlying all inputs.

Response

[Please refer to the response to Board staff interrogatory # 52.](#)

Interrogatory

Question #25 Reference: i) Exhibit F/Schedule 2/Tab 1

a) Please provide a schedule setting out the components of the total proposed distribution cost of service (including interest expense, allowed return and taxes) for 2008.

b) Please indicate where “Amortization of Regulatory Assets” for 2008 is described and detailed in the Application. If not already in the evidence, please provide:

- A description of each of the Regulatory Asset accounts contributing the 2008 amortization value.
- The basis for the 2008 amortization value for each account.
- A continuity schedule for each Regulatory Asset account from year end 2005 through to year end 2008.

Response

a)

Revenue Requirement:

	Test 2008
<u>Cost of Service</u>	
Operating, Maintenance & Administration	\$ 42,076
Depreciation & Amortization	\$ 34,357
CDM	\$ -
Capital Taxes	\$ 1,482
Income Taxes	\$ 11,769
	<u>\$ 89,684</u>
<u>Less: Non-Rate Revenues</u>	
Specific Service Charges	\$ 1,282
Late Payment Charges	\$ 420
Other Distribution Revenue (RCVA)	\$ 329
Other Income & Deductions	\$ 2,832
ADMIN Revenue	\$ 477
Total Revenue Offsets	<u>\$ 5,341</u>
Base Revenue Requirement	\$ 84,343
<u>Return on Capital</u>	
Rate Base	\$ 505,404
Cost of Capital	<u>7.46%</u>
Return on Capital	\$ 37,723
TOTAL REVENUE REQUIREMENT	\$ 122,066
Transformer Allowance	\$ 2,042
TOTAL REVENUE REQUIREMENT	\$ 124,108

- b) The Regulatory Asset Accounts that contributes to the 2008 Amortization value are: 1) Account 1508 Sub Account OEB Deferred Assessed Costs; 2) Account 1508 Sub Account OMERS Deferred Pension Costs and 3) Account 1590 Recovery of Regulatory Asset Balances. See Board IR #42 and #43 for a description of these accounts.

Amortization of Regulatory Asset Balances flow through costs and are based on account balances that have been approved by the OEB for recovery and in certain cases for return to customers where accounts have been over-recovered.

Account 1508 OEB Assessed Costs are related to the 2004 OEB Assessed costs that are amortized over a two year period to end April 2008.

Account 1508 OMERS Pension Costs are related to the 2004 OMERS Pension costs that are amortized over a two year period to end April 2008.

Account 1590 represents the Recovery of Regulatory Asset Balances that have been approved for recovery from and amounts refunded to customers. Account 1590 includes, 1) the transfer of balances that have been approved in the Board's 2004 Decision regarding the Recovery of Regulatory Asset balances, 2) the October 3, 2006 Review & Vary Decision which result in a net refund of certain balances to customers and the transfer of balances for LV variance up to April 30, 2006 according the OEB's Frequently Asked Questions of December 2005 and Guidelines of June 13, 2006. Recovery of account 1590 will expire April 2008.

- Please see the response to Board staff interrogatory #44.

Interrogatory

Question #26 Reference: i) Exhibit G/Schedule 1/Tab 1

ii) Board's December 9, 2004 Decision regarding the Recovery of Regulatory Assets

a) Please provide a schedule linking the \$124.108 in planned recoveries through base distribution rates set out on page 1 of reference (i) to the proposed 2008 distribution cost of service.

b) Please provide the filings Enersource made to the OEB in response to the direction on pages 86 and 87 of reference (ii).

c) Please provide continuity schedules for each of the Regulatory Asset accounts dealt with in reference (i) from **December 31, 2003 through to December 31, 2006. For each account please show separately the annual amounts refunded to/recovered from customers, any new "postings" to the account and interest accrued.**

d) Please provide a schedule detailing the variance and regulatory asset accounts whose December 31st, 2006 balances contribute to the \$8.552 M being returned to customers through rate riders. In each case, please provide:

- A description of each variance/regulatory asset account, including the Board decision authorizing the account, unless addressed in reference (ii)**
- A continuity schedule showing the annual changes in the account since its inception through to December 31st 2006, unless already addressed in response to c).**

e) Please provide further details on each of the following items for which rate riders are proposed (including a description and details on the period over which the amount was accrued and how the accrued amount was determined):

- Past Over Recovery of the LCT**
- Low Voltage Charges levied by HONI**
- Ontario Price Credit Administrative costs**

f) Please provide details as to which Regulatory Asset accounts the \$1.537 M in interest costs proposed for recovery is associated, including:

- A breakdown the interest costs by Regulatory Asset account**
- The period over which the interest cost on each account were accrued, and**
- Why interest costs were not included in the determination of the Regulatory Asset account's balance.**

Response

a. Please see the response to interrogatory #25.a.

b. Enersource assumes that the referenced Decision pertains to the Board's December 10, 2004 Decision on Enersource's Third Tranche Conservation and Demand Management spending (RP-2004-0203). The reporting obligations required in paragraphs 81, 82 and 89 are available on the Board's website.

c. Please see the attached spreadsheet.

d. Please see the responses to interrogatories #25 and #26 (c), and to the response to Board staff interrogatory #42.
Please see the attached spreadsheet.

e. Information on the past over recovery of Large Corporation Tax is provided at the response to Board staff interrogatory # 42.
Information on the past over recovery of Low Voltage charges levied by Hydro One is provided at the response to Board staff interrogatory # 42.
Information on the past over recovery of Ontario Price Credit Administrative Costs is provided at the response to Board staff interrogatory # 46.

f. Please see the responses to interrogatories #25 and #26 (c).
Interest costs have been included in the determination of the Regulatory Asset account balance. Account 1590, to which the \$1.537 M relates to will be fully recovered in April 2008. The net amount of \$1.537 M represents the interest that is projected to be outstanding on account 1590 for which we are now seeking to recover.

Interrogatory

Question #27 Reference: i) Exhibit G/Schedule 2/Tabs 3 and 4 Preamble:

Tab 4, page 1 of reference (iii) states that the assignment of class responsibility of the refund/recovery is (with the exception of the LRAM and SSM) consistent with the 2006 EDR treatment of the subject amounts. The evidence then states that “historic revenue responsibility ratios” were used to allocate all amounts to classes except for those associated with the LRAM and SSM:

a) Please provide a schedule that sets out each of the variance and regulatory asset accounts and the other items contributing to the \$5.118 M refund and, for each:

- Indicate whether its assignment to customer classes was addressed in the 2006 EDR and, if so, how.**

- Indicate how it will be allocated to customer classes for 2008 rates**

b) Please describe fully what is meant by “historic revenue responsibility ratios”.

Response

Variance and Regulatory Asset Accounts

a) Was the item assigned to customer classes in 2006 EDR and how?

- Ontario Price Credit Admin Costs-not applicable to 2006 EDR
- Large Corporation Tax Over Recovery-not applicable to 2006 EDR
- Deferred OEB Costs-In the Board’s October 3, 2006 Decision on Motion EB-2006-0109, Enersource was allowed to recover deferred OEB costs for 2004 through rate riders beginning November 1, 2006. By granting the Motion, the original 2006 EDR Decision was, therefore, varied accordingly. This item was assigned to customer classes using the method described below for 2008 test year.
- OMERS Pension Deferral-In the Board’s October 3, 2006 Decision on Motion EB-2006-0109, Enersource was allowed to recover deferred OMERS Pension costs for 2004 through rate riders beginning November 1, 2006. By granting the Motion, the original 2006 EDR Decision was, therefore, varied accordingly. This item was assigned to customer classes using the method described below for 2008 test year.
- Interest on Regulatory Assets- not applicable to 2006 EDR

- RSVA Balances returned to customers- In the Board's October 3, 2006 Decision on Motion EB-2006-0109, Enersource was allowed to recover RSVA balances up to December 31, 2004 through rate riders beginning November 1, 2006. By granting the Motion, the original 2006 EDR Decision was, therefore, varied accordingly. This item was assigned to customer classes using the method described below for 2008 test year.
- Low Voltage Charges-this item was assigned to customer classes in 2006 EDR using the method described below for 2008 test year.
- LRAM and SSM amounts-Enersource did not request these amounts in 2006 EDR.

How will the item be allocated to customer classes for 2008 rates?

Enersource proposes to allocate consistent with the 2006 EDR treatment. All customer class allocations of variance and regulatory asset amounts for the 2008 test year were made based on each class' proportional responsibility for Enersource revenue requirement (other than for LRAM and SSM claims). That proportion was determined by multiplying projected 2008 customer connections and total kWh for each customer class by current rates, and then comparing the resulting customer class revenue to the resulting total distribution revenue. In this manner, Enersource is able to fairly allocate the amounts to each customer class based on the proportion of distribution revenue they are expected to provide in 2008.

b) What is meant by "historic revenue responsibility ratios"?

The term "historic revenue responsibility ratios" refers to the use of current rates (not the new rates being applied for) to determine revenues for each customer class. The term "historic" is not entirely accurate, although the 2006 EDR ratios are similar to the ratios used in this application. Enersource will use the 2006 EDR treatment for the allocations.

Interrogatory

Question #28 Reference: i) Exhibit G/Schedule 2/Tab 5

a) Please provide a copy of Sheet O2 (Monthly Fixed Charge Min & Max Worksheet) from Enersource's January 15, 2007 filing.

Response

[Please see attached Cost Allocation filing sheet O2.](#)

Interrogatory

Question #29 Reference: i) Exhibit H/Schedule 1/Tab 1, page 2

a) Based on a recent 12 consecutive months of actual billing data, please indicate the percentage of total residential customers that:

- Consume less than 100 kWh per month
- Consume 100 -> 250 kWh per month
- Consume 250 -> 500 kWh per month
- Consume 500 -> 800 kWh per month

Response

<u>Category</u>	<u>Percentage</u>
Less than 100 kWh per month	0.2
100 -> 250 kWh per month	2.1
250 -> 500 kWh per month	18.1
500 -> 800 kWh per month	35.3

Interrogatory

Question #30 Reference: i) Exhibit H/Schedule 2/Tab 6

- a) If not provided in response to Question #1, please provide copies of the Decision and Order for EB-2005-0465 and EB-2005-0560.**
- b) Did either decision identify any shortcomings in supporting data provided by Enersource or other analysis/information that Enersource should provide prior to the interim rates being made final**

Response

- a) Please see the response to VECC Interrogatory #1.
- b) Neither decision identified shortcomings in the supporting data provided by Enersource or other analysis/information that Enersource should provide prior to interim rates being made final.

VECC Interrogatories

Index of Attachments

1. #1 VECC IR_ Mar 9, 2006 Interim Rate Order.pdf
2. #1 VECC IR_April 12, 2006 Decision & Order.pdf
3. #1 VECC IR_April 12, 2007 Decision & Order.pdf
4. #1 VECC IR_Mar 18, 2005 Decision & Order.pdf
5. #1 VECC IR_Nov 29, 2005 Interim Rate Order.pdf
6. #1 VECC IR_Oct 3, 2006 Decision.pdf
7. #1 VECC IR_Oct 27, 2006 Rate order.pdf
8. #9 VECC IR.pdf
9. #11b VECC IR_ExB Sch3 Tab2 _ Appendix A_ Updated _Demand Tab.pdf
10. #11b VECC IR_ExB Sch3 Tab2 _ Appendix A_ Updated _Energy Tab.pdf
11. #11b VECC IR_ExB Sch3 Tab2 _ Appendix A_ Updated.pdf
12. #11e VECC IR Econometric Drivers for Load Forecast.pdf
13. #11e VECC IR_Short Term Load Forecasts Statistical Parameters_Energy Consumption.pdf
14. #11e VECC IR_Short Term Load Forecasts Statistical Parameters_Peak Demand.pdf
15. #26b VECC IR_RP-2004-0069-EB-2004-0055.pdf
16. #26d VECC IR.pdf
17. #26c VECC IR.pdf
18. #28 VECC IR.pdf



RP-2005-0013
EB-2005-0051

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

AND IN THE MATTER OF an Application by
Enersource Hydro Mississauga Inc. for an order or
orders approving or fixing just and reasonable rates.

BEFORE: Gordon Kaiser
Vice Chair and Presiding Member

Paul Vlahos
Member

Pamela Nowina
Member

DECISION AND ORDER

Background and Application

In November 2003 the Ontario government announced that it would permit local distribution companies to apply to the Board for the next installment of their allowable return on equity beginning March 1, 2005. The Government also indicated that the Board's approval would be conditional on a financial commitment to reinvest in conservation and demand management initiatives, an amount equal to one year's incremental returns.

Also in November 2003, the Government announced, in conjunction with the introduction of Bill 4, the *Ontario Energy Board Amendment Act, (Electricity Pricing), 2003*, that electricity distributors could start recovering Regulatory Assets in their rates, beginning March 1, 2004, over a four year period.

In February and March, 2004, the Board approved the applications of distributors to recover 25% of their December 31, 2002 Regulatory Asset balances (or additional amounts for rate stability) in their distribution rates on an interim basis effective March 1, 2004 and implemented on April 1, 2004.

On December 20, 2004 the Board issued filing guidelines to all electricity distribution utilities for the April 1, 2005 distribution rate adjustments. The guidelines allowed the applicants to recover three types of costs. These costs concern (i) the rate recovery of the third tranche of the allowable return on equity (Market Adjusted Revenue Requirement or "MARR"), (ii) the 2005 proxy allowance for payments in lieu of taxes ("PILs") and (iii) a second installment of the recovery of Regulatory Assets.

A generic Notice of the proceedings was published on January 25, 2005 in major newspapers in the province, which provided a 14 day period for submissions from interested parties. On February 4, 2005, the Board issued Procedural Order No. 1, providing for an extension for submissions until February 16, 2005 and also providing for reply submissions from applicants and other parties.

The Applicant filed an application for adjustments to their rates for the following amounts:

MARR: \$ 8,263,000

2005 PILs Proxy: \$ 12,769,591

Regulatory Assets: The Applicant also included the rate riders for the first of a three year recovery of regulatory assets as subsequently approved by the Board in the December 9, 2004 Decision with Reasons and the March 14, 2005 Order (RP-2004-0069/EB-2004-0323).

Submissions

The Board received one submission which addressed the 2005 rate setting process in general. This submission was made by School Energy Coalition (SEC). SEC objected to the guideline which caused the recovery of the 2005 PILs proxy to be reflected only on the variable charge. SEC was also concerned that monthly service charges and overall distribution charges varied significantly between utilities across the province. SEC also raised concerns regarding the consistency of, and access to, information on the applications as filed by the utilities.

Reply submissions to SEC's general submissions were received from the Coalition of Large Distributors, the Electricity Distributors Association, Hydro One Networks, and the LDC Coalition (a group of 7 distributors). These parties generally argued against the recommendations put forward by SEC, by and large indicating that the Board's existing processes for 2006 and 2007 have been planned to address these issues going forward and that these issues should not be added to the 2005 rates adjustment process.

The Applicant was not specifically named in any of these submissions.

The full record of the proceeding is available for review at the Board's offices.

Board Findings

The Board first addresses the general submission of SEC. While SEC raises important issues regarding electricity distribution rates, the Board has put in place a process which will address most of the issues raised by SEC on a comprehensive basis with coordinated cost of service, cost allocation and cost of capital studies for all distributors in 2006, 2007 and 2008. The Board does agree that unless there are compelling reasons to diverge from the Board's original filing guidelines for the 2005 distribution rate adjustment process, distributors should follow the guidelines in their applications.

The Board finds that the application conforms with earlier decisions of the Board (including approval for the Applicant's Conservation and Demand Management plan), directives and guidelines.

The Board will issue a separate decision on cost awards.

THE BOARD ORDERS THAT:

- 1) The rate schedule attached as Appendix "A" is approved effective March 1, 2005, to be implemented on April 1, 2005. All other rates currently in effect that are not shown on the attached schedule remain in force. If the Applicant's billing system is not capable of prorating to accommodate the April 1, 2005 implementation date, the new rates shall be implemented with the first billing cycle for electricity consumed or estimated to have been consumed after April 1, 2005.

- 2) The Applicant shall notify its customers of the rate changes, no later than with the first bill reflecting the new rates and include the brochure provided by the Board.

DATED at Toronto, March 18, 2005

ONTARIO ENERGY BOARD



Peter H. O'Dell
Assistant Board Secretary

Appendix "A"

RP-2005-0013
EB-2005-0051

March 18, 2005

ONTARIO ENERGY BOARD

Enersource Hydro Mississauga Inc.
Schedule of Changed Distribution Rates and Charges

Effective Date: March 1, 2005
Implementation Date: April 1, 2005

RP-2005-0013
EB-2005-0051

RESIDENTIAL

Monthly Service Charge	(per month)	\$10.23
Distribution Volumetric Rate	(per kWh)	\$0.0103
Final Rate Rider	(per kWh)	\$0.0029

SMALL COMMERCIAL

Monthly Service Charge	(per month)	\$13.20
Distribution Volumetric Rate	(per kWh)	\$0.0241
Final Rate Rider	(per kWh)	\$0.0010

GENERAL SERVICE < 50 KW

Monthly Service Charge	(per month)	\$26.40
Distribution Volumetric Rate	(per kWh)	\$0.0136
Final Rate Rider	(per kWh)	\$0.0012

GENERAL SERVICE > 50 KW TO 499 kw

Monthly Service Charge	(per month)	\$67.44
Distribution Volumetric Rate	(per kW)	\$4.0296
Final Rate Rider	(per kW)	\$0.3500

GENERAL SERVICE > 500 KW TO 4999 KW

Monthly Service Charge	(per month)	\$1,139.50
Distribution Volumetric Rate	(per kW)	\$1.5267
Final Rate Rider	(per kW)	-\$0.0100

LARGE USE

Monthly Service Charge	(per month)	\$12,054.91
Distribution Volumetric Rate	(per kW)	\$2.5109
Final Rate Rider	(per kW)	\$0.0300

STREET LIGHTING (Non Time of Use)

Monthly Service Charge	(per connection)	\$0.35
Distribution Volumetric Rate	(per kW)	\$2.6280
Final Rate Rider	(per kW)	\$0.2500

Enersource Hydro Mississauga Inc.
Schedule of Changed Distribution Rates and Charges

Effective Date: March 1, 2005
Implementation Date: April 1, 2005

RP-2005-0013
EB-2005-0051

UMETERED SCATTERED LOAD

Billed as Small Commercial

Monthly Service Charge	(per month)	\$13.20
Distribution Volumetric Rate	(per kWh)	\$0.0241
Final Rate Rider	(per kWh)	\$0.0010

The final rate riders on this schedule reflect the first of the three year recovery of regulatory assets as approved in the December 9, 2004 Decision with Reasons and the March 14, 2005 Order.



EB-2005-0465

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

AND IN THE MATTER OF an application by Enersource Hydro
Mississauga Inc. for an Order or Orders pursuant to section 78 of
the *Ontario Energy Board Act, 1998* for 2006 distribution rates and
related matters;

AND IN THE MATTER OF an application by Enersource Hydro
Mississauga Inc. for an Interim Order or Orders pursuant to
sections 78 and 21(7) of the *Ontario Energy Board Act, 1998*
authorizing certain rates, charges and charge parameter in
connection with the provision of distribution service to Integrated
Gas Recovery Service Inc.'s Britannia Sanitary Landfill electricity
generation facility.

INTERIM ORDER

By letter dated October 5, 2005, Enersource Hydro submitted an application seeking an interim order, effective September 15, 2005, authorizing certain rates, charges and charge parameter applicable to a methane fuelled generating facility commissioned by Integrated Gas Recovery Services Inc. ("IGRS") at the Britannia Sanitary Landfill ("BSL") site in the City of Mississauga. Enersource Hydro proposed the following:

- an administrative charge of \$200.00/month;
- a customer charge of \$67.44/month;
- a distribution facilities charge in an amount equal to the product of the \$4.3796/kW and the Demand Contract Quantity;
- an overrun distribution facilities charge in an amount equal to the product of \$4.3796/kW and each kW supplied by Enersource Hydro in excess of the Demand Contract Quantity; and
- a Demand Contract Quantity initially set at 400 kW.

The proposed customer charge and the proposed variable rate are the Board approved rates for Enersource's customers classified as GS >50 kW to 499kW. The monthly administration charge is based on the incremental costs incurred by Enersource for manual intervention by settlement staff in the billing process. These costs are based on 3 hours per month of work with a weighted average hourly rate of \$70. Enersource Hydro chose to round the resulting \$210 of costs down to \$200.

The Contract Demand Quantity is based on Enersource Hydro's supply of electricity to BSL under black start conditions. Enersource Hydro stated that IGRS has established the BSL generation station's Contract Demand Quantity at 400 kW.

Also, as part of the application Enersource Hydro submitted a letter originally sent to IGRS informing the subject customer of the proposed interim rates, charges and charge parameter. The letter, dated September 28, 2005 was returned to Enersource Hydro signed by the Director of IGRS accepting the rates, charges and charge parameter as proposed by Enersource Hydro in EB-2005-0465.

Enersource Hydro is currently authorized to charge \$2.60/kW for standby service as per the Board's order in RP-2000-0035/EB-2001-0323. However, Enersource stated that it did not propose to apply this rate to the subject customer because of the following:

- It was established for a load displacing device rather than a merchant generator
- It does not compensate the distributor for costs incurred to manually intervene in the settlement and billing process
- It is not consistent with customer specific variable distribution rates.

With the exception of the monthly administration charge, all other rates and charges proposed in this application are based on Board approved rates and charges for the subject customer class.

In regards to its 2006 EDR filing in RP-2005-0020/EB-2005-0360, Enersource Hydro stated that it intends to update that application by incorporating the rates and charges requested in the instant proceeding. That application will request the interim order be finalized as part of the 2006 rates process subject to any alterations or revisions that may result from the Board's adjudication of that application. Therefore,

THE BOARD ORDERS THAT:

1. Enersource Hydro is granted interim approval for its proposed rates, charges and charge parameter as filed on October 5, 2005.
2. The rate schedule attached is approved on an interim basis, to be incorporated in Enersource Hydro's 2006 electricity distribution rate application.

DATED AT Toronto, November 29, 2005

ONTARIO ENERGY BOARD

Original signed by

Peter H. O'Dell
Assistant Board Secretary

**Interim Rate Schedule
Enersource Hydro Mississauga Inc.
EB-2005-0465**

Applicability

This rate schedule applies to Enersource Hydro Mississauga Inc.'s provision of distribution service to Integrated Gas Recovery Services Inc. ("IGRS"), Britannia Sanitary Landfill ("BSL") generating facility.

Distribution Service Rates and Charges for the BSL Generating Facility

Monthly administrative charge:	\$	200.00
Monthly Customer Charge:	\$	67.44
Monthly distribution facilities rate:	\$	4.3796/kW
Variable overrun distribution service rate:	\$	4.3796/kW

Contract Demand Quantity

The applicable Monthly Contract Demand Quantity is initially set at 400 kW.

Billing Determinant

The monthly distribution facilities rate is applied to the Contract Demand Quantity.

The variable overrun distribution service rate is applied to each kilowatt of demand delivered by Enersource Hydro to IGRS's BSL generating facility in the current month that exceeds the Contract Demand Quantity. Demand is measured by Enersource Hydro's meter at the interconnection of IGRS's BSL generating facility and Enersource Hydro's distribution system.

Terms and Conditions

The applicable terms and conditions of service are set out in Enersource Hydro's Conditions of Service.



RP-2005-0020
EB-2005-0360
EB-2005-0560

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

AND IN THE MATTER OF an application by Enersource
Hydro Mississauga Inc. for an Order or Orders pursuant to
section 78 of the *Ontario Energy Board Act, 1998* for 2006
distribution rates and related matters;

AND IN THE MATTER OF an application by Enersource
Hydro Mississauga Inc. for an Interim Order or Orders
pursuant to sections 78 and 21(7) of the *Ontario Energy
Board Act, 1998* authorizing certain rates, charges and
charge parameter in connection with the provision of
distribution service to the Greater Toronto Airports Authority.

BEFORE:

Bob Betts
Presiding Member
Cathy Spoel
Member
Ken Quesnelle
Member

INTERIM ORDER

By letter received December 29, 2005, Enersource Hydro Mississauga Inc. (the
“Applicant”) submitted an application seeking an interim order, effective

December 15, 2005, authorizing certain rates, charges and charge parameter applicable to the Greater Toronto Airports Authority ("GTAA"). The Applicant proposed:

- A \$500.00 per month administrative charge
- A gross metered load charge parameter relying on currently approved distribution rates applicable to the Large User customer class.
- The currently approved distribution rates for the Large User class are:
Monthly Fixed Charge \$12,054.91
Variable Distribution Rate \$2.5409/kW

This application was given file number EB 2005-0540. The Board notes that this application was filed within the context of the Applicant's 2006 distribution rate application (RP-2005-0020/EB-2005-0360).

The proposed customer charge and the proposed variable rate are the Board approved rates for Enersource Hydro's customers classified as Large User. The monthly administration charge is based on the incremental costs incurred by the Applicant because its settlement staff must manually intervene in the billing process. These costs are based on 7 hours per month of work with a weighted average hourly rate of \$70. The Applicant chose to round the resulting \$490 of costs up to \$500.

The Applicant stated that it has negotiated a Connection Agreement with the GTAA, which includes the Applicant's provision of distribution service after the generating facility is commissioned and charging for distribution service using a gross load charge parameter and an administrative charge. The Applicant requested that the interim order be approved without a written hearing since it does not affect any other person and is limited to the Applicant and the GTAA.

Enersource Hydro is currently authorized to charge \$2.60/kW for standby service as per the Board's order in RP-2000-0035/EB-2001-0323. However, Enersource stated that it did not propose to apply this rate to the subject customer because of the following:

- This rate was established by the former regulator and is out of date
- This rate was not adjusted to recover the Applicant's MARR or PILs
- It was established as a universal rate therefore, charging this rate implies a cross-subsidization between any eligible customer and all comparable customers of similar load.

With the exception of the monthly administration charge, all other rates and charges proposed in this application are based on Board approved rates and charges for the subject customer class.

By letter dated January 6, 2005, the GTAA submitted a response to the Applicant's request for an interim order. The GTAA disputed several points in the Applicant's evidence regarding the appropriateness of using the gross load billing parameter in determining standby variable rates.

However, the GTAA submitted that the issues dealing with what constitutes an appropriate rate are best examined in the main EDR application and in the GTAA's submission following a cost allocation study and a study of the impact of the generation facility. The Board notes that the GTAA has been actively involved in the Applicant's main EDR application and in the Generic Issues proceeding.

Consequently, the GTAA stated that it supports the Applicant's request for approval of the subject application without a written hearing, as long as the Board does not rule on the appropriateness of the proposed standby rates and charges. The GTAA also noted, for the purpose of the subject application and within the context of the Connection Agreement with Enersource Hydro, that it has accepted the proposed rate as an interim

rate pending the final resolution of the issue by the Board. The GTAA stated that it takes no position on the administrative charge at this time.

The Board notes that the matter of finalizing the interim order with regards to the GTAA will be determined as part of Enersource Hydro's 2006 rates application subject to any alterations or revisions that may result from the Board's adjudication of that application. In addition, the Board notes that although the GTAA supports the proposed rates as an interim measure to facilitate Enersource Hydro's provision of service to the GTAA, it did reserve the right to take an opposite position on any application by Enersource Hydro to the Board, relating to these matters.

THEREFORE, THE BOARD ORDERS THAT:

1. Enersource Hydro is granted interim approval for its proposed rates, charges and charge parameter as filed on December 29, 2005.
2. The rate schedule attached as Appendix A is approved on an interim basis.

DATED AT Toronto, March 9, 2006

Ontario Energy Board

Original signed by

Peter H. O'Dell
Assistant Board Secretary

APPENDIX "A"

TO THE INTERIM ORDER

RP-2005-0020

EB-2005-0360

EB-2005-0560

March 9, 2006

ONTARIO ENERGY BOARD

**Interim Rate Schedule
Enersource Hydro Mississauga Inc.
RP-2005-0020/EB-2005-0360
EB-2005-0560**

Applicability

This rate schedule applies to Enersource Hydro Mississauga Inc.'s provision of distribution service to The Greater Toronto Airport Authority ("GTAA").

Distribution Service Rates and Charges for the GTAA

Monthly administrative charge:	\$	500.00
Monthly Customer Charge:	\$	12,054.91
Variable distribution service rate:	\$	2.5409/kW

Billing Determinant

The variable distribution rate is applied to the Gross Metered Load.

Terms and Conditions

The applicable terms and conditions of service are set out in Enersource Hydro's Conditions of Service.



RP-2005-0020
EB-2005-0360

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

AND IN THE MATTER OF an Application by Enersource
Hydro Mississauga Inc. for an order or orders approving
or fixing just and reasonable distribution rates and other
charges, effective May 1, 2006.

BEFORE: Paul Vlahos
Presiding Member

Bob Betts
Member

DECISION AND ORDER

Enersource Hydro Mississauga Inc. (“Enersource” or the “Applicant”) is a licensed distributor providing electrical service to consumers within its defined service area. Enersource filed an Application (the “Application”) with the Ontario Energy Board (the “Board”) for an order or orders approving or fixing just and reasonable rates for the distribution of electricity and other matters, to be effective May 1, 2006.

Enersource is one of over 90 electricity distributors in Ontario that are regulated by the Board. To streamline the process for the approval of distribution rates and charges for these distributors, the Board developed and issued the 2006 Electricity Distribution Rate Handbook (the “Handbook”) and complementary spreadsheet-based models. These materials were developed after extensive public consultation with distributors, customer groups, public and environmental interest groups, and other interested parties. The Handbook contains requirements and guidelines for filing an application. The models determine the amounts to be included for the payments in lieu of taxes (“PILs”) and

calculate rates based on historical financial and other information entered by the distributor.

Also included in this process was a methodology and model for the final recovery of regulatory assets flowing from the Board's decision dated December 9, 2004 on the Review and Recovery of Regulatory Assets – Phase 2 for Toronto Hydro, London Hydro, Enersource Hydro Mississauga and Hydro One Networks Inc. ("Hydro One").

As a distributor that is embedded in Hydro One Network's low voltage system, the Applicant has included the recovery of certain Regulatory Assets that have been allocated by Hydro One Networks. The amount claimed by the Applicant was provided by Hydro One Networks as a reasonable approximation of the actual amount that Hydro One Networks will assess the Applicant. To the degree that the amount differs from the actual amount approved for Hydro One Networks in another proceeding (RP-2005-0020/EB-2005-0378), this difference will be reconciled at the end of the Regulatory Asset recovery period, as set out in the Phase 2 regulatory assets decision issued on December 9, 2004 (RP-2004-0064/RP-2004-0069/RP-2004-0100/RP-2004-0117/RP-2004-0118).

In its preliminary review of the 2006 rate applications received from the distributors, the Board identified several issues that appeared to be common to many or all of the distributors. As a result, the Board held a hearing (EB-2005-0529) to consider these issues (the "Generic Issues Proceeding") and released its decision (the "Generic Decision") on March 21, 2006. The rulings flowing from that Generic Decision apply to this Application, except to the extent noted in this Decision. The Board notes that pursuant to ss. 21 (6.1) of the *Ontario Energy Board Act, 1998*, and to the extent that it is pertinent to this Application, the evidentiary record of the Generic Issues Proceeding is part of the evidentiary record upon which the Board is basing this Decision.

In December 2001, the Board authorized the establishment of deferral accounts by the distributors related to the payments that the distributors make to the Ministry of Finance in lieu of taxes. The Board is required, under its enabling legislation, to make an order with respect to non-commodity deferral accounts once every twelve months. The Board has considered the information available with respect to these accounts and orders that the amounts recorded in the accounts will not be reflected in rates as part of the Rate

Order that will result from this Decision. The Board will continue to monitor the accounts with a view to clearing them when appropriate.

Public notice of the rate Application made by Enersource was given through newspaper publication in its service area. The evidence filed was made available to the public. Interested parties intervened in the proceeding. The evidence in the Application was tested through written interrogatories from Board staff and intervenors, and intervenors and Enersource had the opportunity to file written argument. While the Board has considered the entire record in this proceeding, it has made reference in this Decision only to such evidence and argument as is necessary to provide context to its findings.

Enersource has requested an amount of \$128,405,947 as revenue to be recovered through distribution rates and charges. Included in this amount is a debit of \$11,298,678 for the recovery of regulatory assets. Except where noted in this Decision, the Board finds that Enersource has filed its Application in accordance with the Handbook.

Notwithstanding Enersource's general compliance with the Handbook and associated models, in considering this Application the Board reviewed the following matters in detail:

- Low Voltage Rates;
- Conservation and Demand Management ("CDM") Funding;
- Tier 1 adjustment – Unfilled Vacancies;
- Loss factors;
- Deferral accounts;
- Revised regulatory assets;
- Affiliate transactions; and
- Consequences of the Generic Decision (EB-2005-0529).

Low Voltage Rates

Enersource included in its Application recovery of ongoing Low Voltage ("LV") charges that Hydro One Networks will be levying on Enersource for Low Voltage wheeling distribution services provided to Enersource.

The Board notes that this estimate reflects Hydro One Networks' current approved LV rate of \$0.56/kW. The Board further notes that Hydro One Networks applied for an LV rate of \$0.63/kW in its 2006 rate application RP-2005-0020/EB-2005-0378, and the Board has approved this rate.

The Board is of the view that the LV adjustment that Enersource has included in its Application is insufficient to recover its expected LV charges in 2006, as this amount does not reflect the updated Hydro One Networks rate. Although the Generic Decision provides that embedded distributors are to track differences between LV costs charged by the host distributor(s) and corresponding revenues recovered from ratepayers, the Board seeks to minimize systemic sources of variance. The Board is of the view that Enersource's rates should reflect the LV rates authorized by the Board for the host distributor. Accordingly, the Board has revised the amount for LV charge recovery in Enersource's revenue requirement.

CDM Funding

Enersource has applied for approval to recover \$1,525,000 in distribution rates to be invested in CDM activities. Enersource has proposed three residential programs for 2006. These three programs are:

- Hot Water Tune Up Program;
- Seasonal Light Exchange Program;
- Events Van program.

The Vulnerable Energy Consumers Coalition ("VECC") expressed concern that 100% of the costs are allocated to the residential class. VECC noted that 65% of the CDM spending is associated with the Events Van and the distribution of compact fluorescent lights. VECC argued that it would be wrong to assume that residential class customers are the sole beneficiaries of the program, and therefore that the costs for the program should not be entirely assigned to the residential class. Also, VECC noted that Enersource Hydro should target some of the CDM spending specifically at low income consumers.

Enersource indicated that it could not measure the extent of spill-over into other rate classes to allocate costs in a meaningful way. The Board notes VECC's concerns, but agrees with Enersource that determining an alternate allocation methodology would be

difficult. The Board also notes that VECC did not propose an alternative. With regard to VECC's concerns about low income customers, the Board notes that low-income program targets are not specifically required under the Board's guidelines for incremental CDM spending. In addition, Enersource has stated that its program is open to all customers including low-income customers.

The Board notes that Enersource has performed the Total Resource Cost effectiveness screening required for approval, and the programs satisfy the Board's prudence test for CDM investments. The Board therefore accepts Enersource's CDM plan and will include the costs in 2006 rates.

Tier 1 adjustment – Unfilled Vacancies

Enersource requested that \$1,131,601 be included in distribution rates in order to reflect the existence in 2004 of 23 vacant positions that are over and above the normal number of vacant positions of 15. Enersource stated that the adjustment is needed so that its actual 2004 personnel costs more closely resemble those of a typical year.

VECC argued that the adjustment should be limited to \$520,000 to reflect a lower average salary, specifically that of union staff, and the difference in full time equivalent positions between 2003 and 2004 as shown on schedule 6-4 of the Handbook.

The School Energy Coalition ("SEC") argued that Enersource had not demonstrated how the unfilled vacancies and associated costs of \$1,131,601 qualify as an appropriate Tier 1 adjustment and should be disallowed. SEC noted that although Enersource claimed that these vacancies are unsustainable, the utility admitted that overtime expense for the period of the hiring freeze was the lowest of the 2002-2004 period.

The Board notes Enersource's explanation that it was able to sustain normal operations at acceptable levels due to a cooler than normal summer in 2004. The Board also notes that Enersource defended the lack of additional overtime expense in the Application by stating that the majority of overtime worked was by employees not eligible for compensation for overtime. However, the Board is not persuaded by the evidence that Enersource would not operate efficiently in a typical year under current staffing levels. The Board therefore will not approve the Applicant's request for \$1,131,601 for unfilled vacancies. The Applicant provided no specific details on how and where the new personnel would be used and why they are needed. It is open to

the Applicant to come forward with more information supporting the need for increased staffing levels in a future filing. Accordingly, the Board has revised the EDR and PILs models to reflect the removal of the entire amount relating to the unfilled vacancy adjustment.

Loss factors

The Handbook requires distributors to calculate the distribution loss factor ("DLF") and enter the value in the appropriate cell(s) of the EDR model. The model then automatically calculates the total loss factor by applying the current supply facilities loss factor to the new DLF. It is this total loss factor which should be applied to the rate classes. Enersource applied the DLF instead of the total loss factor.

The Board finds that in the absence of more information on the nature of the data provided by Enersource, the appropriate value to be applied is the total loss factor of 1.0433 as per sheet 8-7 of the model. Accordingly, the Board has revised the EDR model to reflect this adjustment.

Deferral accounts

Enersource requested an accounting order establishing two deferral accounts to track costs associated with a new Customer Information System and costs associated with the implementation of risk management initiatives.

VECC submitted that requests for deferral accounts such as these are inconsistent with the choice of Historical Test Year for the purpose of determining 2006 rates and should be denied. SEC added that the Applicant had the option to file on a forward test year basis and to include and justify expected costs outside of its 2004 costs.

The Board agrees with VECC and SEC that such requests are not consistent with a historical test year filing and therefore denies the request to establish these deferral accounts.

Revised regulatory asset rate riders

Enersource proposed to revise its approved regulatory asset rate riders to include additional regulatory asset amounts in the form of 2004 and 2005 OEB and Pension costs, and Hydro One's post-January 1, 2004 charges. In addition, the Applicant requested that the recovery for these incremental amounts be realized in one year as

opposed to over the remaining two years of the mandated four year recovery period.

With respect to the 2005 OEB costs, the Board indicated in a December 20, 2004 letter to electricity distributors that it would consider the disposition of the 2005 OEB dues recorded in Account 1508 in this proceeding. However, given that the final 2005 OEB dues are not available because of the difference in fiscal years for the Board and the distributors, the Board will review and dispose of the 2005 OEB dues at a later time.

With respect to the 2005 Pension Costs, the Applicant's request is unique among historical test year filers. Notwithstanding the Board's communication regarding the OEB costs mentioned above, a request for the disposition of other 2005 amounts recorded in account 1508 or in any other variance account are outside the scope of the Board's guidelines on the current recovery of regulatory assets. Although these guidelines were targeted to the remaining distributors who have not received final approval of their regulatory assets, Enersource should follow the intent of the guidelines when requesting an update to their approved rate riders and limited their request to 2004 year end amounts. Therefore, the Board finds that the 2005 Pension costs should not be recovered in rates at the present time and should be carried forward for disposition at a later time.

With respect to the request for recovery of the incremental amounts over a one year period, the Board finds that Enersource has not provided a persuasive argument as to why the incremental rate riders should not be congruent with the legacy rate riders. Accordingly, the Board has adjusted the EDR model to reflect a two year recovery period for the other incremental amounts approved in this Decision.

Affiliate Transactions

Enersource acquires a large number of services from its parent company and purchases these services through an annual Management Fee. The Board has the responsibility to determine the prudence of all such costs, and needs detailed information on which to base its judgment. The Applicant has presented its information clearly and has been helpful in its responses to interrogatories, but the record is still not at a satisfactory level. In future, further information will be required concerning the costs for services provided by the parent company via the Management Fee, and how these costs relate to other costs shown elsewhere in the Application, for example in Schedules 6-4, 6-5 and 6-6.

The Board notes that the upcoming cost allocation study may address its concerns to some extent, as long as the study encompasses all those activities of the affiliated entity for which Enersource pays. The Applicant is cautioned that in future, more detailed information will be required on affiliate costs.

Consequences of the Generic Decision on this Application

The Generic Decision contains findings relevant to funding for smart meters for electricity distributors. The Applicant did file a specific smart meter plan in the revenue requirement. In this situation, the Generic Decision provides that an amount determined as \$3.50 per meter per month installed during the rate year be reflected in the Applicant's revenue requirement, instead of the smart meter-related costs proposed by the Applicant. As there is a variance account, and for simplicity, the Board has not made any distinction for purposes of setting rates between the meter costs for residential and non-residential customers. Consequently, the amounts that the Applicant has proposed in the 2006 rate Application have been removed and replaced with the amount determined in accordance with the Generic Decision. Furthermore, the Board finds in this Decision that this smart meter revenue will be allocated to all metered customers and recovered through the monthly service charge. The revised amount is reflected in the approved monthly service charges contained in the Tariff of Rates and Charges appended to this Decision. Pursuant to the Generic Decision, a variance account will be established, the details of which will be communicated in due course.

With respect to standby rates, the Generic Decision provided that existing and proposed standby rates should be declared interim upon the effective date of the rates approved in this Decision. Enersource currently has an approved standby rate. However, in related proceedings (EB-2005-0465 and EB-2005-0560) the Board approved, on an interim basis, new standby rates and charges for a merchant generator at the Britannia Landfill site in Mississauga and for a load displacing device commissioned by the Greater Toronto Airport Authority. These rates were approved on November 29, 2005 and March 9, 2006 respectively in order to facilitate Enersource's service to these customers, whose generators were due to be commissioned before May 1, 2006. These rates were based in part on the Applicant's normal distribution rates at the time of the filing. The revisions to distribution rates caused by this Decision will amend the rates to some degree. The rates remain interim in accordance with the Generic

Decision, and are effective as of the date of the Tariff of Rates and Charges accompanying this Decision.

With regard to Enersource's generally applicable legacy standby rate, this rate is declared interim at the current level as of the effective date of the Tariff of Rates and Charges accompanying this Decision, regardless of whether or not that rate is currently applied to any other customer.

Resulting Revenue Requirement

As a result of the Board's determinations on these issues, the Board has adjusted the revenue requirement to be recovered through distribution rates and charges to \$121,401,972, including a debit amount of \$8,641,750 for the recovery of Regulatory Assets.

Cost Awards

This Application is one of a number of applications before the Board dealing with 2006 rates chargeable by distributors. Intervenors may be parties to multiple applications and, if eligible, their costs associated with a specific distributor may not be separable. Therefore, for these applications, the matter of intervenor cost awards will be addressed by the Board at a later date, upon the conclusion of the current rate applications. If an intervenor that is eligible to recover its costs is able to uniquely identify its costs associated with this Application, it must file its cost claim within 10 days from the receipt of this Decision.

THE BOARD ORDERS THAT:

1. The Tariff of Rates and Charges set out in Appendix "A" of this Order is approved, effective May 1, 2006, for electricity consumed or estimated to have been consumed on and after May 1, 2006. The application of the revised distribution rates shall be prorated to May 1, 2006. If Enersource Hydro Mississauga Inc.'s billing system is not capable of prorating changed loss factors jointly with distribution rates, the revised loss factors shall be implemented upon the first subsequent billing for each billing cycle.
2. The Tariff of Rates and Charges set out in Appendix "A" of this Order supersedes all previous distribution rate schedules approved by the Ontario Energy Board for

Enersource Hydro Mississauga Inc., and is final in all respects, except for the standby rates which are approved as interim.

3. Enersource Hydro Mississauga Inc. shall notify its customers of the rate changes no later than with the first bill reflecting the new rates.

DATED at Toronto, April 12, 2006.

ONTARIO ENERGY BOARD

A handwritten signature in black ink, appearing to read "John Zych". The signature is fluid and cursive, with the first name "John" and the last name "Zych" clearly distinguishable.

John Zych
Board Secretary

Appendix "A"

RP-2005-0020
EB-2005-0360

April 12, 2006

ONTARIO ENERGY BOARD

Enersource Hydro Mississauga Inc.

TARIFF OF RATES AND CHARGES

Effective May 1, 2006

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

RP-2005-0020
EB-2005-0360

APPLICATION

- The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Codes, Guidelines or Orders of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.
- No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.
- This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2006 for all consumption or deemed consumption services used on or after that date.
SPECIFIC SERVICE CHARGES - May 1, 2006 for all charges incurred by customers on or after that date.
LOSS FACTOR ADJUSTMENT – May 1, 2006 unless the distributor is not capable of prorating changed loss factors jointly with distribution rates. In that case, the revised loss factors will be implemented upon the first subsequent billing for each billing cycle.

SERVICE CLASSIFICATIONS

Residential

This classification refers to all residential services including, without limitation, single family or single unit dwellings, multi-family dwellings, row-type dwellings and subdivision developments. Energy is supplied in single phase, 3-wire, or three phase, 4-wire, having a nominal voltage of 120/240 Volts. There shall be only one delivery point to a dwelling.

General Service Less Than 50 kW

This classification refers to a non-residential account whose monthly average peak demand is less than, or is forecast to be less than, 50 kW.

Small Commercial and Unmetered Scattered Load

This classification applies to an account taking electricity at 750 volts or less whose average monthly maximum demand is less than, or is forecast to be less than, 50 kW and the consumption is either metered or unmetered. While this customer class includes about 350 existing metered customers, metered customers are no longer added to this customer class. The unmetered connections include cable TV power packs, bus shelters, telephone booths, traffic lights, railway crossings, etc. The level of the consumption will be agreed to by the distributor and the customer, based on detailed manufacturer information/documentation with regard to electrical consumption of the unmetered load or periodic monitoring of actual consumption.

General Service 50 to 499 kW

This classification refers to a non-residential account whose monthly average peak demand is equal to or greater than, or is forecast to be equal to or greater than, 50 kW but less than 500 kW. Note that for the application of the Retail Transmission Rate – Network Service Rate and the Retail Transmission Rate – Line and Transformation Connection Service Rate the following sub-classifications apply:

- General Service 50 to 499 kW non-interval metered
- General Service 50 to 499 kW interval metered

General Service 500 to 4,999 kW

This classification refers to a non-residential account whose monthly average peak demand is equal to or greater than, or is forecast to be equal to or greater than, 500 kW but less than 5,000 kW.

Large Use

This classification refers to an account whose monthly average peak demand is equal to or greater than, or is forecast to be equal to or greater than, 5,000 kW.

Standby Power

This classification refers to an account that has load displacement generation and requires Enersource Hydro Mississauga to

Enersource Hydro Mississauga Inc.

TARIFF OF RATES AND CHARGES

Effective May 1, 2006

**This schedule supersedes and replaces all previously
approved schedules of Rates, Charges and Loss Factors**

RP-2005-0020

EB-2005-0360

provide back-up service.

Street Lighting

This classification refers to an account for roadway lighting with a Municipality. Street lighting equipment in the City of Mississauga is owned by the City of Mississauga. All street lighting will be non-metered with energy consumption based on the connected wattage and calculated hours of use using the approved methods and rates established by the OEB. Street lighting plant, facilities, or equipment owned by the Customer is subject to the Ontario Electrical Safety Code (latest edition) and the Electrical Safety Authority requirements.

MONTHLY RATES AND CHARGES

Residential

Service Charge	\$	11.19
Distribution Volumetric Rate	\$/kWh	0.0120
Regulatory Asset Recovery	\$/kWh	0.0031
Retail Transmission Rate – Network Service Rate	\$/kWh	0.0059
Retail Transmission Rate – Line and Transformation Connection Service Rate	\$/kWh	0.0051
Wholesale Market Service Rate	\$/kWh	0.0052
Rural Rate Protection Charge	\$/kWh	0.0010
Regulated Price Plan – Administration Charge	\$	0.25

General Service Less Than 50 kW

Service Charge	\$	28.54
Distribution Volumetric Rate	\$/kWh	0.0146
Regulatory Asset Recovery	\$/kWh	0.0014
Retail Transmission Rate – Network Service Rate	\$/kWh	0.0053
Retail Transmission Rate – Line and Transformation Connection Service Rate	\$/kWh	0.0046
Wholesale Market Service Rate	\$/kWh	0.0052
Rural Rate Protection Charge	\$/kWh	0.0010
Regulated Price Plan – Administration Charge	\$	0.25

Small Commercial and Unmetered Scattered Load

Service Charge for metered account	\$	14.14
Service Charge for Unmetered Scattered Load account (per connection)	\$	13.83
Distribution Volumetric Rate	\$/kWh	0.0253
Regulatory Asset Recovery	\$/kWh	0.0015
Retail Transmission Rate – Network Service Rate	\$/kWh	0.0053
Retail Transmission Rate – Line and Transformation Connection Service Rate	\$/kWh	0.0046
Wholesale Market Service Rate	\$/kWh	0.0052
Rural Rate Protection Charge	\$/kWh	0.0010
Regulated Price Plan – Administration Charge	\$	0.25

Enersource Hydro Mississauga Inc.

TARIFF OF RATES AND CHARGES

Effective May 1, 2006

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

RP-2005-0020
EB-2005-0360

General Service 50 to 499 kW

Service Charge	\$	72.18
Distribution Volumetric Rate	\$/kW	4.3249
Regulatory Asset Recovery	\$/kW	0.3907
Retail Transmission Rate – Network Service Rate	\$/kW	2.1136
Retail Transmission Rate – Line and Transformation Connection Service Rate	\$/kW	1.8109
Retail Transmission Rate – Network Service Rate – Interval Metered	\$/kW	2.1136
Retail Transmission Rate – Line and Transformation Connection Service Rate – Interval Metered	\$/kW	1.8109
Wholesale Market Service Rate	\$/kWh	0.0052
Rural Rate Protection Charge	\$/kWh	0.0010
Regulated Price Plan – Administration Charge (if applicable)	\$	0.25

General Service 500 to 4,999 kW

Service Charge	\$	1,221.31
Distribution Volumetric Rate	\$/kW	1.6657
Regulatory Asset Recovery	\$/kW	0.0140
Retail Transmission Rate – Network Service Rate – Interval Metered	\$/kW	2.0449
Retail Transmission Rate – Line and Transformation Connection Service Rate – Interval Metered	\$/kW	1.7719
Wholesale Market Service Rate	\$/kWh	0.0052
Rural Rate Protection Charge	\$/kWh	0.0010
Regulated Price Plan – Administration Charge (if applicable)	\$	0.25

Large Use

Service Charge	\$	13,049.13
Distribution Volumetric Rate	\$/kW	2.7524
Regulatory Asset Recovery	\$/kW	0.0607
Retail Transmission Rate – Network Service Rate – Interval Metered	\$/kW	2.1820
Retail Transmission Rate – Line and Transformation Connection Service Rate – Interval Metered	\$/kW	1.8924
Wholesale Market Service Rate	\$/kWh	0.0052
Rural Rate Protection Charge	\$/kWh	0.0010
Regulated Price Plan – Administration Charge (if applicable)	\$	0.25

Standby Power – APPROVED ON AN INTERIM BASIS

Except for the Integrated Gas Recovery Services' Britannia Sanitary Landfill and the Greater Toronto Airport Authority that are identified separately, the Standby Charge will be applied for a month where standby power is not provided. The charge is applied to the contracted amount (e.g. nameplate rating of generation facility). Further servicing details are available in Enersource Hydro's Conditions of Service.

\$/kW 2.60

The Integrated Gas Recovery Services' ("IGRS") Britannia Sanitary Landfill generating facility ("BSL"):

In addition to its regular account's monthly Service Charge, Enersource Hydro will charge IGRS the General Service 50 to 499 kW Distribution Volumetric Charge applied to the monthly contract demand quantity, initially set at 400 kW. A variable overrun distribution rate equal to the General Service 50 to 499 kW Distribution Volumetric Charge is applied to each kilowatt of demand delivered by Enersource Hydro to IGRS's BSL generating facility in the current month that exceeds the contract demand quantity. Demand is measured by Enersource Hydro's meter at the interconnection of IGRS' BSL generating facility and Enersource Hydro's distribution system. A monthly administration charge of \$200 is applied to IGRS' account for the manual intervention by settlement staff in the billing process. Further servicing details are available in Enersource Hydro's Conditions of Service.

Enersource Hydro Mississauga Inc.

TARIFF OF RATES AND CHARGES

Effective May 1, 2006

**This schedule supersedes and replaces all previously
approved schedules of Rates, Charges and Loss Factors**

RP-2005-0020
EB-2005-0360

The Greater Toronto Airport Authority ("GTAA"):

In addition to its regular account's monthly Service Charge, Enersource Hydro will charge GTAA the Large Use Distribution Volumetric Charge applied to the monthly gross metered load. A monthly administration charge of \$500 is applied to the GTAA's account for the manual intervention by settlement staff in the billing process. Further servicing details are available in Enersource Hydro's Conditions of Service.

Street Lighting

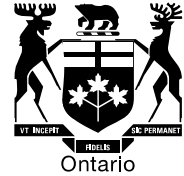
Service Charge (per connection)	\$	0.36
Distribution Volumetric Rate	\$/kW	2.7055
Regulatory Asset Recovery	\$/kW	0.2885
Retail Transmission Rate – Network Service Rate	\$/kW	1.4637
Retail Transmission Rate – Line and Transformation Connection Service Rate	\$/kW	1.3094
Wholesale Market Service Rate	\$/kWh	0.0052
Rural Rate Protection Charge	\$/kWh	0.0010
Regulated Price Plan – Administration Charge (if applicable)	\$	0.25

Specific Service Charges

Customer Administration		
Arrears Certificate	\$	15.00
Request for other billing information	\$	15.00
Credit reference/credit check (plus credit agency costs)	\$	15.00
Credit reference/credit check (plus credit agency costs – General Service)	\$	25.00
Income tax letter	\$	15.00
Returned cheque (plus bank charges)	\$	12.50
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	\$	30.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable – Residential)	\$	20.00
Meter dispute charge plus Measurement Canada fees (if meter found correct)	\$	10.00
Special meter reads	\$	30.00
Interval meter request change	\$	40.00
Non-Payment of Account		
Late Payment - per month	%	1.50
Late Payment - per annum	%	19.56
Collection of account charge – no disconnection	\$	9.00
Disconnect/Reconnect at meter - during regular hours	\$	20.00
Disconnect/Reconnect at pole - during regular hours	\$	185.00
Disconnect/Reconnect at pole - after regular hours	\$	415.00
Temporary service install and remove – overhead – no transformer	\$	400.00
Specific Charge for Access to the Power Poles – per pole/year	\$	22.35
Allowances		
Transformer Allowance for Ownership - per kW of billing demand/month	\$	(0.40)
Primary Metering Allowance for transformer losses – applied to measured demand and energy	%	(1.00)

LOSS FACTORS

Total Loss Factor – Secondary Metered Customer < 5,000 kW	1.0433
Total Loss Factor – Secondary Metered Customer > 5,000 kW	1.0145
Total Loss Factor – Primary Metered Customer < 5,000 kW	1.0328
Total Loss Factor – Primary Metered Customer > 5,000 kW	1.0045



EB-2006-0109

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

AND IN THE MATTER OF an application by Enersource Hydro Mississauga Inc. for an Order or Orders approving and fixing just and reasonable distribution rates and other charges effective May 1, 2006;

AND IN THE MATTER OF a Notice of Motion by Enersource Hydro Mississauga Inc. seeking an Order Varying the Decision and Order of the Board in RP-2005-0020/EB-2005-0360.

BEFORE: Gordon Kaiser
Presiding Member and Vice Chair

Paul Vlahos
Member

Cynthia Chaplin
Member

DECISION ON MOTION

October 3, 2006

Background

On June 12, 2006, Enersource Hydro Mississauga Inc. ("Enersource") filed a Notice of Motion ("Motion") with the Ontario Energy Board ("Board") in relation to the Board's Decision and Order dated April 12, 2006 (the "original decision") in the application by Enersource for 2006 electricity distribution rates ("the original application"), under file number RP-2005-0020/EB-2005-0360.

In the original decision, the Board had disallowed Enersource's proposal for a Tier 1 non-routine unusual adjustment for unfilled vacancies in the amount of \$1,131,601 on the basis that it was not persuaded by the evidence that Enersource would not operate efficiently in a typical year under current staffing levels. However, the Board also stated that it was open to Enersource to come forward with more information supporting the need for increased staffing levels.

The Motion sought an order of the Board which would permit: (1) the recovery of the previously denied Tier 1 adjustment, (2) the recovery of the incremental Payments in Lieu of taxes expense related to this adjustment, and (3) adjustments to rate riders to dispose of the balances recorded in certain Retail Settlement Variance Accounts as of December 31, 2004.

On July 24, 2006, the Board issued Procedural Order No. 1 which established the process for a written hearing. The School Energy Coalition (SEC) was the only party other than the Applicant to make written submissions in this Motion proceeding. SEC opposed Enersource's request.

Decision on the Motion

The main ground of SEC's opposition to the relief sought is that Enersource's proposed adjustment does not meet the criteria for either a Tier 1 or a Tier 2 adjustment, and therefore it should be disallowed. The Board notes the April 12, 2006 original decision had stated that Enersource had provided no specific details on the requested Tier 1 non-routine unusual adjustment, but that it was open to the Applicant to come forward with more information supporting the need for increased staffing levels in a future filing. The Board is of the view that the additional information

provided by the Applicant in this filing has produced a reasonable record documenting the circumstances which resulted in the need for the adjustment.

The Board has also been guided by its decision in the Oshawa PUC Networks Inc. (Oshawa) proceeding (RP-2005-0020/EB-2005-0402) involving somewhat similar circumstances. Oshawa had requested approval to increase its staffing levels which had been reduced in recent years for the purpose of lowering its fixed costs as well as due to retirements, attrition and re-organization. The Board recognized in that decision Oshawa's need to increase staffing levels to perform the work directly supporting safe distribution system operations and, therefore, allowed an increase in staffing levels.

The Board has given little weight to the issues raised by Enersource or SEC regarding weather normalization, comparative rates between Enersource and other electricity distributors, and financial or service quality considerations. None of these matters separately or collectively were found to be of consequence to what the Board needed to decide in this case.

For these reasons, the Board accepts Enersource's request that the Tier 1 non-routine unusual adjustment be allowed, along with the recovery of the incremental Payments in Lieu of taxes expense.

To implement the relief it sought, Enersource requested that the Board approve adjustments to rate riders to dispose of the balances recorded in certain Retail Settlement Variance Accounts as of December 31, 2004. Although this request is not an appeal to any aspect of the original decision, the Board grants that request as it will operate to mitigate the rate impacts on Enersource's customers associated with the approval of the Tier 1 adjustment.

The Board grants the Motion and the original decision is therefore varied accordingly. Enersource is directed to submit a draft Rate Order within 15 days of implementing this decision.

SEC requested that it be awarded 100% of its reasonably incurred costs. Enersource did not respond to SEC's request. The Board awards SEC 100% of its reasonable incurred costs associated with this Motion. SEC shall file a statement of costs the Board and Enersource no later than October 13, 2006. Should Enersource have any comments concerning any of the cost claims, these shall be forwarded to the Board

and SEC by October 20, 2006. Any response to Enersource's comments shall be filed with the Board and Enersource by October 27, 2006. Enersource shall pay the costs awarded upon receipt of the Board's cost order.

DATED at Toronto, October 3, 2006

ONTARIO ENERGY BOARD

Gordon Kaiser
Presiding Member & Vice Chair

Original signed by

Paul Vlahos
Member

Original signed by

Cynthia Chaplin
Member

Original signed by



EB-2006-0109

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

AND IN THE MATTER OF a motion by Enersource Hydro
Mississauga Inc. requesting the Board to review and vary
certain aspects of Decision and Order RP-2005-0020 / EB-
2005-0360 dated April 12, 2006.

BEFORE: Gordon Kaiser
Presiding Member and Vice Chair

Paul Vlahos
Member

Cynthia Chaplin
Member

**RATE ORDER ARISING FROM THE DECISION ON THE MOTION OF
OCTOBER 3, 2006**

Enersource Hydro Mississauga Inc. ("Enersource") filed an application, dated August 2, 2005, with the Ontario Energy Board under section 78 of the *Ontario Energy Board Act*, S.O. 1998, c.15, Schedule B as amended, for an order or orders approving or fixing just and reasonable rates for the distribution of electricity, to be effective as of May 1, 2006. The Board assigned file number RP-2005-0020 / EB-2005-0360 to the application.

The Board issued its Decision and Order related to this application on April 12, 2006.

On June 12, 2006, Enersource filed with the Board a motion requesting that the Board review and vary certain aspects of the Decision and Order. The Board assigned file number EB-2006-0109 to this application.

On July 24, 2006, the Board issued Procedural Order No. 1 establishing, among other things, that it would consider the motion by way of a written hearing.

On October 3, 2006, the Board issued its Decision approving the relief sought by Enersource and directing the Applicant to come forward with a draft Rate Order giving effect to the Decision within 15 days of implementing this Decision.

On October 16, 2006, Enersource filed two draft tariff schedules reflecting the Board's Decision. The Board has reviewed the draft tariff schedules and accepts them as filed, subject to the correction of minor typographical errors.

THE BOARD ORDERS THAT:

1. The Tariff of Rates and Charges attached as Appendix A is approved effective November 1, 2006.
2. The Tariff of Rates and Charges attached as Appendix B is approved for the period November 1, 2006 to April 30, 2007.

ISSUED at Toronto, October 27, 2006

ONTARIO ENERGY BOARD

Original signed by

Peter H. O'Dell
Assistant Board Secretary

**APPENDIX "A" TO
ENERSOURCE HYDRO MISSISSAUGA INC.
RATE ORDER
BOARD FILE NO. EB-2006-0109
DATED: October 27, 2006**

Enersource Hydro Mississauga Inc.

TARIFF OF RATES AND CHARGES

Effective November 1, 2006

**This schedule supersedes and replaces all previously
approved schedules of Rates, Charges and Loss Factors**

EB-2006-0109

APPLICATION

- The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Codes, Guidelines or Orders of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.
- No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.
- This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - November 1, 2006 for all consumption or deemed consumption services used on or after that date.
SPECIFIC SERVICE CHARGES - November 1, 2006 for all charges incurred by customers on or after that date.
LOSS FACTOR ADJUSTMENT – November 1, 2006 unless the distributor is not capable of prorating changed loss factors jointly with distribution rates. In that case, the revised loss factors will be implemented upon the first subsequent billing for each billing cycle.

SERVICE CLASSIFICATIONS

Residential

This classification refers to all residential services including, without limitation, single family or single unit dwellings, multi-family dwellings, row-type dwellings and subdivision developments. Energy is supplied in single phase, 3-wire, or three phase, 4-wire, having a nominal voltage of 120/240 Volts. There shall be only one delivery point to a dwelling.

General Service Less Than 50 kW

This classification refers to a non-residential account whose monthly average peak demand is less than, or is forecast to be less than, 50 kW.

Small Commercial and Unmetered Scattered Load

This classification applies to an account taking electricity at 750 volts or less whose average monthly maximum demand is less than, or is forecast to be less than, 50 kW and the consumption is either metered or unmetered. While this customer class includes about 350 existing metered customers, metered customers are no longer added to this customer class. The unmetered connections include cable TV power packs, bus shelters, telephone booths, traffic lights, railway crossings, etc. The level of the consumption will be agreed to by the distributor and the customer, based on detailed manufacturer information/documentation with regard to electrical consumption of the unmetered load or periodic monitoring of actual consumption.

General Service 50 to 499 kW

This classification refers to a non-residential account whose monthly average peak demand is equal to or greater than, or is forecast to be equal to or greater than, 50 kW but less than 500 kW. Note that for the application of the Retail Transmission Rate – Network Service Rate and the Retail Transmission Rate – Line and Transformation Connection Service Rate the following sub-classifications apply:

- General Service 50 to 499 kW non-interval metered
- General Service 50 to 499 kW interval metered

General Service 500 to 4,999 kW

This classification refers to a non-residential account whose monthly average peak demand is equal to or greater than, or is forecast to be equal to or greater than, 500 kW but less than 5,000 kW.

Large Use

This classification refers to an account whose monthly average peak demand is equal to or greater than, or is forecast to be equal to or greater than, 5,000 kW.

Enersource Hydro Mississauga Inc.

TARIFF OF RATES AND CHARGES

Effective November 1, 2006

**This schedule supersedes and replaces all previously
approved schedules of Rates, Charges and Loss Factors**

EB-2006-0109

Standby Power

This classification refers to an account that has load displacement generation and requires Enersource Hydro Mississauga to provide back-up service.

Street Lighting

This classification refers to an account for roadway lighting with a Municipality. Street lighting equipment in the City of Mississauga is owned by the City of Mississauga. All street lighting will be non-metered with energy consumption based on the connected wattage and calculated hours of use using the approved methods and rates established by the OEB. Street lighting plant, facilities, or equipment owned by the Customer is subject to the Ontario Electrical Safety Code (latest edition) and the Electrical Safety Authority requirements.

MONTHLY RATES AND CHARGES

Residential

Service Charge	\$	11.31
Distribution Volumetric Rate	\$/kWh	0.0121
Regulatory Asset Recovery	\$/kWh	0.0028
Retail Transmission Rate – Network Service Rate	\$/kWh	0.0059
Retail Transmission Rate – Line and Transformation Connection Service Rate	\$/kWh	0.0051
Wholesale Market Service Rate	\$/kWh	0.0052
Rural Rate Protection Charge	\$/kWh	0.0010
Regulated Price Plan – Administration Charge	\$	0.25

General Service Less Than 50 kW

Service Charge	\$	28.84
Distribution Volumetric Rate	\$/kWh	0.0148
Regulatory Asset Recovery	\$/kWh	0.0011
Retail Transmission Rate – Network Service Rate	\$/kWh	0.0053
Retail Transmission Rate – Line and Transformation Connection Service Rate	\$/kWh	0.0046
Wholesale Market Service Rate	\$/kWh	0.0052
Rural Rate Protection Charge	\$/kWh	0.0010
Regulated Price Plan – Administration Charge	\$	0.25

Small Commercial and Unmetered Scattered Load

Service Charge for metered account	\$	14.29
Service Charge for Unmetered Scattered Load account (per connection)	\$	13.98
Distribution Volumetric Rate	\$/kWh	0.0256
Regulatory Asset Recovery	\$/kWh	0.0008
Retail Transmission Rate – Network Service Rate	\$/kWh	0.0053
Retail Transmission Rate – Line and Transformation Connection Service Rate	\$/kWh	0.0046
Wholesale Market Service Rate	\$/kWh	0.0052
Rural Rate Protection Charge	\$/kWh	0.0010
Regulated Price Plan – Administration Charge	\$	0.25

Enersource Hydro Mississauga Inc.

TARIFF OF RATES AND CHARGES

Effective November 1, 2006

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2006-0109

General Service 50 to 499 kW

Service Charge	\$	72.96
Distribution Volumetric Rate	\$/kW	4.3715
Regulatory Asset Recovery	\$/kW	0.3293
Retail Transmission Rate – Network Service Rate	\$/kW	2.1136
Retail Transmission Rate – Line and Transformation Connection Service Rate	\$/kW	1.8109
Retail Transmission Rate – Network Service Rate – Interval Metered	\$/kW	2.1136
Retail Transmission Rate – Line and Transformation Connection Service Rate – Interval Metered	\$/kW	1.8109
Wholesale Market Service Rate	\$/kWh	0.0052
Rural Rate Protection Charge	\$/kWh	0.0010
Regulated Price Plan – Administration Charge (if applicable)	\$	0.25

General Service 500 to 4,999 kW

Service Charge	\$	1,234.56
Distribution Volumetric Rate	\$/kW	1.6835
Regulatory Asset Recovery	\$/kW	(0.0222)
Retail Transmission Rate – Network Service Rate – Interval Metered	\$/kW	2.0449
Retail Transmission Rate – Line and Transformation Connection Service Rate – Interval Metered	\$/kW	1.7719
Wholesale Market Service Rate	\$/kWh	0.0052
Rural Rate Protection Charge	\$/kWh	0.0010
Regulated Price Plan – Administration Charge (if applicable)	\$	0.25

Large Use

Service Charge	\$	13,190.70
Distribution Volumetric Rate	\$/kW	2.7819
Regulatory Asset Recovery	\$/kW	0.0143
Retail Transmission Rate – Network Service Rate – Interval Metered	\$/kW	2.1820
Retail Transmission Rate – Line and Transformation Connection Service Rate – Interval Metered	\$/kW	1.8924
Wholesale Market Service Rate	\$/kWh	0.0052
Rural Rate Protection Charge	\$/kWh	0.0010
Regulated Price Plan – Administration Charge (if applicable)	\$	0.25

Standby Power – APPROVED ON AN INTERIM BASIS

Except for the Integrated Gas Recovery Services' Britannia Sanitary Landfill and the Greater Toronto Airport Authority that are identified separately, the Standby Charge will be applied for a month where standby power is not provided. The charge is applied to the contracted amount (e.g. nameplate rating of generation facility). Further servicing details are available in Enersource Hydro's Conditions of Service.

\$/kW 2.60

The Integrated Gas Recovery Services' ("IGRS") Britannia Sanitary Landfill generating facility ("BSL"):

In addition to its regular account's monthly Service Charge, Enersource Hydro will charge IGRS the General Service 50 to 499 kW Distribution Volumetric Charge applied to the monthly contract demand quantity, initially set at 400 kW. A variable overrun distribution rate equal to the General Service 50 to 499 kW Distribution Volumetric Charge is applied to each kilowatt of demand delivered by Enersource Hydro to IGRS's BSL generating facility in the current month that exceeds the contract demand quantity. Demand is measured by Enersource Hydro's meter at the interconnection of IGRS' BSL generating facility and Enersource Hydro's distribution system. A monthly administration charge of \$200 is applied to IGRS' account for the manual intervention by settlement staff in the billing process. Further servicing details are available in Enersource Hydro's Conditions of Service.

Enersource Hydro Mississauga Inc.

TARIFF OF RATES AND CHARGES

Effective November 1, 2006

**This schedule supersedes and replaces all previously
approved schedules of Rates, Charges and Loss Factors**

EB-2006-0109

The Greater Toronto Airport Authority ("GTAA"):

In addition to its regular account's monthly Service Charge, Enersource Hydro will charge GTAA the Large Use Distribution Volumetric Charge applied to the monthly gross metered load. A monthly administration charge of \$500 is applied to the GTAA's account for the manual intervention by settlement staff in the billing process. Further servicing details are available in Enersource Hydro's Conditions of Service.

Street Lighting

Service Charge (per connection)	\$	0.36
Distribution Volumetric Rate	\$/kW	2.7346
Regulatory Asset Recovery	\$/kW	0.2304
Retail Transmission Rate – Network Service Rate	\$/kW	1.4637
Retail Transmission Rate – Line and Transformation Connection Service Rate	\$/kW	1.3094
Wholesale Market Service Rate	\$/kWh	0.0052
Rural Rate Protection Charge	\$/kWh	0.0010
Regulated Price Plan – Administration Charge (if applicable)	\$	0.25

Specific Service Charges

Customer Administration		
Arrears Certificate	\$	15.00
Request for other billing information	\$	15.00
Credit reference/credit check (plus credit agency costs)	\$	15.00
Credit reference/credit check (plus credit agency costs – General Service)	\$	25.00
Income tax letter	\$	15.00
Returned cheque (plus bank charges)	\$	12.50
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	\$	30.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable – Residential)	\$	20.00
Meter dispute charge plus Measurement Canada fees (if meter found correct)	\$	10.00
Special meter reads	\$	30.00
Interval meter request change	\$	40.00
Non-Payment of Account		
Late Payment - per month	%	1.50
Late Payment - per annum	%	19.56
Collection of account charge – no disconnection	\$	9.00
Disconnect/Reconnect at meter - during regular hours	\$	20.00
Disconnect/Reconnect at pole - during regular hours	\$	185.00
Disconnect/Reconnect at pole - after regular hours	\$	415.00
Temporary service install and remove – overhead – no transformer	\$	400.00
Specific Charge for Access to the Power Poles – per pole/year	\$	22.35
Allowances		
Transformer Allowance for Ownership - per kW of billing demand/month	\$	(0.40)
Primary Metering Allowance for transformer losses – applied to measured demand and energy	%	(1.00)

LOSS FACTORS

Total Loss Factor – Secondary Metered Customer < 5,000 kW	1.0433
Total Loss Factor – Secondary Metered Customer > 5,000 kW	1.0145
Total Loss Factor – Primary Metered Customer < 5,000 kW	1.0328
Total Loss Factor – Primary Metered Customer > 5,000 kW	1.0045

**APPENDIX "B" TO
ENERSOURCE HYDRO MISSISSAUGA INC.
RATE ORDER
BOARD FILE NO. EB-2006-0109
DATED: October 27, 2006**

Enersource Hydro Mississauga Inc.

TARIFF OF RATE RIDERS

Effective November 1, 2006 to April 30, 2007

EB-2006-0109

SERVICE CLASSIFICATIONS

Residential

This classification refers to all residential services including, without limitation, single family or single unit dwellings, multi-family dwellings, row-type dwellings and subdivision developments. Energy is supplied in single phase, 3-wire, or three phase, 4-wire, having a nominal voltage of 120/240 Volts. There shall be only one delivery point to a dwelling.

General Service Less Than 50 kW

This classification refers to a non-residential account whose monthly average peak demand is less than, or is forecast to be less than, 50 kW.

Small Commercial and Unmetered Scattered Load

This classification applies to an account taking electricity at 750 volts or less whose average monthly maximum demand is less than, or is forecast to be less than, 50 kW and the consumption is either metered or unmetered. While this customer class includes about 350 existing metered customers, metered customers are no longer added to this customer class. The unmetered connections include cable TV power packs, bus shelters, telephone booths, traffic lights, railway crossings, etc. The level of the consumption will be agreed to by the distributor and the customer, based on detailed manufacturer information/documentation with regard to electrical consumption of the unmetered load or periodic monitoring of actual consumption.

General Service 50 to 499 kW

This classification refers to a non-residential account whose monthly average peak demand is equal to or greater than, or is forecast to be equal to or greater than, 50 kW but less than 500 kW. Note that for the application of the Retail Transmission Rate – Network Service Rate and the Retail Transmission Rate – Line and Transformation Connection Service Rate the following sub-classifications apply:

- General Service 50 to 499 kW non-interval metered
- General Service 50 to 499 kW interval metered

General Service 500 to 4,999 kW

This classification refers to a non-residential account whose monthly average peak demand is equal to or greater than, or is forecast to be equal to or greater than, 500 kW but less than 5,000 kW.

Large Use

This classification refers to an account whose monthly average peak demand is equal to or greater than, or is forecast to be equal to or greater than, 5,000 kW.

Standby Power

This classification refers to an account that has load displacement generation and requires Enersource Hydro Mississauga to provide back-up service.

Street Lighting

This classification refers to an account for roadway lighting with a Municipality. Street lighting equipment in the City of Mississauga is owned by the City of Mississauga. All street lighting will be non-metered with energy consumption based on the connected wattage and calculated hours of use using the approved methods and rates established by the OEB. Street lighting plant, facilities, or equipment owned by the Customer is subject to the Ontario Electrical Safety Code (latest edition) and the Electrical Safety Authority requirements.

MONTHLY RATES AND CHARGES

Residential

Service Charge	\$	0.12
Distribution Volumetric Rate	\$/kWh	0.0002
Regulatory Asset Recovery	\$/kWh	(0.0003)

General Service Less Than 50 kW

Enersource Hydro Mississauga Inc.

TARIFF OF RATE RIDERS

Effective November 1, 2006 to April 30, 2007

EB-2006-0109

Service Charge	\$	0.30
Distribution Volumetric Rate	\$/kWh	0.0001
Regulatory Asset Recovery	\$/kWh	(0.0003)

Small Commercial and Unmetered Scattered Load

Service Charge for metered account	\$	0.15
Service Charge for Unmetered Scattered Load account (per connection)	\$	0.15
Distribution Volumetric Rate	\$/kWh	0.0003
Regulatory Asset Recovery	\$/kWh	(0.0008)

General Service 50 to 499 kW

Service Charge	\$	0.78
Distribution Volumetric Rate	\$/kW	0.0465
Regulatory Asset Recovery	\$/kW	(0.0615)

General Service 500 to 4,999 kW

Service Charge	\$	13.25
Distribution Volumetric Rate	\$/kW	0.0178
Regulatory Asset Recovery	\$/kW	(0.0362)

Large Use

Service Charge	\$	141.57
Distribution Volumetric Rate	\$/kW	0.0295
Regulatory Asset Recovery	\$/kW	(0.0463)

Street Lighting

Distribution Volumetric Rate	\$/kW	0.0292
Regulatory Asset Recovery	\$/kW	(0.0582)



EB-2007-0523

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

AND IN THE MATTER OF an application by Enersource
Hydro Mississauga Inc. for an order or orders approving
or fixing just and reasonable distribution rates and other
charges, to be effective May 1, 2007.

BEFORE: Paul Sommerville
Presiding Member

Paul Vlahos
Member

Ken Quesnelle
Member

DECISION AND ORDER

Enersource Hydro Mississauga Inc. ("Enersource") is a licensed distributor providing electrical service to consumers within its licensed service area. Enersource filed an application with the Ontario Energy Board (the "Board") for an order or orders approving or fixing just and reasonable rates for the distribution of electricity and other charges, to be effective May 1, 2007.

Enersource is one of 85 electricity distributors in Ontario that are regulated by the Board. To streamline the process for the approval of distribution rates and charges for these distributors, the Board issued its *Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors* (the "Report") on December 20, 2006. The Report contained the relevant guidelines for 2007 rate adjustments ("the guidelines") for distributors applying for rates only on the basis of the cost of capital and 2nd generation incentive regulation mechanism policies set out in the Report.

Public notice of Enersource's rate application was given through newspaper publication in Enersource's service area. The evidence filed as part of the rate application was made available to the public. Both Enersource and interested parties had the opportunity to file written submissions in relation to the rate application. The Board received a submission from Board staff and a reply submission from Enersource. While the Board has considered the entire record in this rate application, it has made reference only to such evidence and submissions as is necessary to provide context to its findings.

Enersource's rate application was filed on the basis of the guidelines. In fixing new rates and charges for Enersource, the Board has applied the policies described in the Report.

After confirming the accuracy of the 2006 rate tariff and accompanying materials submitted in the rate application, the Board applied its approved price cap index adjustment to distribution rates (fixed and variable) uniformly across all customer classes. The price cap index is calculated as a price escalator less an X-factor of 1.0%, intended to represent input price and productivity trends. Based on the final 2006 data published by Statistics Canada, the Board has established the price escalator to be 1.9%. The resulting price cap index adjustment is therefore 0.9%.

The following components that were included in 2006 rates were removed prior to the application of the price cap index adjustment:

- the large corporation tax allowance;
- the 2006-approved Conservation and Demand Management funding.

The price cap index adjustment was not applied to the following components of the rates:

- the specific service charges;
- the regulatory asset recovery rate rider; and
- the smart meter rate adder (an amount in the fixed components of the rates associated with smart meter cost recovery).

Smart Meter Cost Recovery

Enersource requested an amount for recovery through a rate adder for smart meter costs of \$2.60 per metered customer per month. This amount was reaffirmed in its February 9, 2007 smart meter rate adder filing. Enersource's reply submission of March 21, 2007 revised this number downward to \$2.57 per metered customer per month.

Enersource's original proposal of a smart meter recovery amount of \$2.60 per metered customer per month contained three amounts which the Board staff submission of March 14, 2007 argued appeared not to be allowable recoveries in this proceeding. Staff stated that this conclusion was based upon an examination of the guidelines in the Board Report and the Addendum for Smart Metering Rates of January 29, 2007 (the "Addendum") to the Report, as well as relevant legislation.

The three amounts questioned in the staff submission were: (1) \$0.03 per metered customer per month for costs associated with the change out of Murray Jensen meters; (2) \$0.04 per metered customer per month for costs associated with capital spending on smart meters for General Service greater than 50 kW customers, and (3) \$1.25 per metered customer per month for costs associated with the disposition of 65,000 conventional meters

Enersource, in its reply submission, stated it could accept that the costs associated with the change out of Murray Jensen meters would be properly recoverable through distribution rates rather than through the 2007 smart meter rate adder. Enersource, therefore, revised downward its proposed 2007 smart meter rate adder by \$0.03 to \$2.57 per metered customer per month. The Board accepts Enersource's removal of this amount.

The second of the amounts in question is for capital spending on smart meters for General Service greater than 50 kW customers. The Board staff submission stated that Enersource's request for capital spending on smart meters for General Service greater than 50 kW customers was outside both the guidelines contained in the Addendum and the criteria and requirements for meters and metering equipment, systems and technology contained in Ontario Regulation 426/06 under the *Ontario Energy Board Act, 1998*.

Enersource, in its reply submission, stated that in its view, the regulations did not appear to bar distributors from providing smart meter or smart metering services to consumers, other than residential and small general service, as long as Board approval of the costs related to the provision of such services had been received.

The Board finds that the policy outlined in the Addendum establishes that costs for General Service greater than 50 kW customers are not eligible for recovery in this proceeding. Accordingly, the Board denies Enersource's request for recovery of these costs.

The third of the amounts in question relates to the disposition costs of conventional meters. The staff submission stated that in staff's view, the recovery of costs related to the disposition of existing meters was not one that was included in the Board's smart meter model, nor was it one for which the Board has, as yet, determined a policy. The staff submission also noted that the issue of what the approach should be for recovery of the disposition costs of existing meters was one that would be considered for all distributors as part of the combined proceeding by the Board, as outlined in the Addendum.

Enersource, in its reply submission, stated that, in its view, the Board had considered the treatment of disposition costs and concluded that they are eligible to be recorded in the smart meter variance account, as discussed in the Board's January 16, 2007 letter to electricity distributors on stranded meter costs. Enersource further stated that any adjudication by the Board of this issue in this proceeding would not bind the Board panel in the combined proceeding. Enersource also expressed the concern that if the 2007 smart meter rate adder does not provide for the recovery of disposition costs, Enersource would lack access to an appropriate funding mechanism. In addition, Enersource stated that not only would the balances in its variance accounts be higher than they ought to be, they would also be unfavourable to rate payers.

While the Board is mindful of Enersource's concerns, the Board has not as yet determined a policy for the recovery of the disposition costs of conventional meters. The Board's letter of January 16, 2007, referenced by Enersource, stated that disposition of these costs would be determined in a future proceeding of the Board. As this is an issue common to all distributors, the Board will deal with this matter in the combined proceeding. Accordingly, the Board denies Enersource's request for the recovery of these costs in this proceeding.

The effect of the Board's denial of Enersource's request for recovery of the costs associated with capital spending on smart meters for General Service greater than 50 kW customers and conventional meter disposition is to reduce Enersource's required smart meter rate adder by an amount of \$1.29 per metered customer per month from the amount of \$2.57 per metered customer per month, as proposed in Enersource's reply submission. The Board therefore approves an amount for recovery of \$1.28 per metered customer per month, which is consistent with Board policy.

Enersource's variance accounts for smart meter program implementation costs, previously authorized by the Board, are continued. As the notice of this application indicated, the Board will be holding a combined proceeding to consider, among other things, appropriate recovery of smart meter costs.

Standby Rates

Enersource's standby rates were approved as interim by the Board in its 2006 distribution rates order. The Board is still examining the issues related to standby rates, and is not in a position to make a final order for these rates at this time. The standby rates will be adjusted by the price cap index but remain interim.

The Board has made the necessary adjustments to Enersource's filed 2006 Tariff of Rates and Charges to produce a new Tariff of Rates and Charges to be effective May 1, 2007. The Board finds the rates and charges in the Tariff of Rates and Charges attached as Appendix A to this decision to be just and reasonable.

THE BOARD ORDERS THAT:

1. The Tariff of Rates and Charges set out in Appendix A of this order is approved, effective May 1, 2007, for electricity consumed or estimated to have been consumed on and after May 1, 2007.
2. The Tariff of Rates and Charges set out in Appendix A of this order supersedes all previous distribution rate schedules approved by the Ontario Energy Board for Enersource, and is final in all respects, except for the standby rates which are approved as interim.

3. Enersource shall notify its customers of the rate changes no later than with the first bill reflecting the new rates.

DATED at Toronto, April 12, 2007.

ONTARIO ENERGY BOARD

Original Signed By

Peter H. O'Dell
Assistant Board Secretary

Appendix A

EB-2007-0523

April 12, 2007

ONTARIO ENERGY BOARD

Enersource Hydro Mississauga Inc.

TARIFF OF RATES AND CHARGES

Effective May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2007-0523

APPLICATION

- The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Codes, Guidelines or Orders of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.
- No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.
- This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES – May 1, 2007 for all consumption or deemed consumption services used on or after that date.

SPECIFIC SERVICE CHARGES – May 1, 2007 for all charges incurred by customers on or after that date.

LOSS FACTOR ADJUSTMENT – May 1, 2007 unless the distributor is not capable of prorating changed loss factors jointly with distribution rates. In that case, the revised loss factors will be implemented upon the first subsequent billing for each billing cycle.

SERVICE CLASSIFICATIONS

Residential

This classification refers to all residential services including, without limitation, single family or single unit dwellings, multi-family dwellings, row-type dwellings and subdivision developments. Energy is supplied in single phase, 3-wire, or three phase, 4-wire, having a nominal voltage of 120/240 Volts. There shall be only one delivery point to a dwelling.

General Service Less Than 50 kW

This classification refers to a non-residential account whose monthly average peak demand is less than, or is forecast to be less than, 50 kW.

Small Commercial and Unmetered Scattered Load

This classification applies to an account taking electricity at 750 volts or less whose average monthly maximum demand is less than, or is forecast to be less than, 50 kW and the consumption is either metered or unmetered. While this customer class includes existing metered customers, metered customers are no longer added to this customer class. The unmetered connections include cable TV power packs, bus shelters, telephone booths, traffic lights, railway crossings, etc. The level of the consumption will be agreed to by the distributor and the customer, based on detailed manufacturer information/documentation with regard to electrical consumption of the unmetered load or periodic monitoring of actual consumption.

General Service 50 to 499 kW

This classification refers to a non-residential account whose monthly average peak demand is equal to or greater than, or is forecast to be equal to or greater than, 50 kW but less than 500 kW.

General Service 500 to 4,999 kW

This classification refers to a non-residential account whose monthly average peak demand is equal to or greater than, or is forecast to be equal to or greater than, 500 kW but less than 5,000 kW.

Large Use

This classification refers to an account whose monthly average peak demand is equal to or greater than, or is forecast to be equal to or greater than, 5,000 kW.

Standby Power

This classification refers to an account that has load displacement generation and requires Enersource Hydro Mississauga to provide back-up service.

Enersource Hydro Mississauga Inc.

TARIFF OF RATES AND CHARGES

Effective May 1, 2007

**This schedule supersedes and replaces all previously
approved schedules of Rates, Charges and Loss Factors**

EB-2007-0523

Street Lighting

This classification refers to an account for roadway lighting with a Municipality. Street lighting equipment in the City of Mississauga is owned by the City of Mississauga. All street lighting will be non-metered with energy consumption based on the connected wattage and calculated hours of use using the approved methods and rates established by the OEB. Street lighting plant, facilities, or equipment owned by the Customer is subject to the Ontario Electrical Safety Code (latest edition) and the Electrical Safety Authority requirements.

MONTHLY RATES AND CHARGES

Residential

Service Charge	\$	12.33
Distribution Volumetric Rate	\$/kWh	0.0111
Regulatory Asset Recovery	\$/kWh	0.0028
Retail Transmission Rate – Network Service Rate	\$/kWh	0.0059
Retail Transmission Rate – Line and Transformation Connection Service Rate	\$/kWh	0.0051
Wholesale Market Service Rate	\$/kWh	0.0052
Rural Rate Protection Charge	\$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	\$	0.25

General Service Less Than 50 kW

Service Charge	\$	29.93
Distribution Volumetric Rate	\$/kWh	0.0149
Regulatory Asset Recovery	\$/kWh	0.0011
Retail Transmission Rate – Network Service Rate	\$/kWh	0.0053
Retail Transmission Rate – Line and Transformation Connection Service Rate	\$/kWh	0.0046
Wholesale Market Service Rate	\$/kWh	0.0052
Rural Rate Protection Charge	\$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	\$	0.25

Small Commercial and Unmetered Scattered Load

Service Charge for metered account	\$	15.32
Service Charge for Unmetered Scattered Load account (per connection)	\$	14.04
Distribution Volumetric Rate	\$/kWh	0.0257
Regulatory Asset Recovery	\$/kWh	0.0008
Retail Transmission Rate – Network Service Rate	\$/kWh	0.0053
Retail Transmission Rate – Line and Transformation Connection Service Rate	\$/kWh	0.0046
Wholesale Market Service Rate	\$/kWh	0.0052
Rural Rate Protection Charge	\$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	\$	0.25

Enersource Hydro Mississauga Inc.

TARIFF OF RATES AND CHARGES

Effective May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2007-0523

General Service 50 to 499 kW

Service Charge	\$	74.24
Distribution Volumetric Rate	\$/kW	4.3900
Regulatory Asset Recovery	\$/kW	0.3293
Retail Transmission Rate – Network Service Rate	\$/kW	2.1136
Retail Transmission Rate – Line and Transformation Connection Service Rate	\$/kW	1.8109
Retail Transmission Rate – Network Service Rate – Interval Metered	\$/kW	2.1136
Retail Transmission Rate – Line and Transformation Connection Service Rate – Interval Metered	\$/kW	1.8109
Wholesale Market Service Rate	\$/kWh	0.0052
Rural Rate Protection Charge	\$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	\$	0.25

General Service 500 to 4,999 kW

Service Charge	\$	1,240.76
Distribution Volumetric Rate	\$/kW	1.6906
Regulatory Asset Recovery	\$/kW	(0.0222)
Retail Transmission Rate – Network Service Rate – Interval Metered	\$/kW	2.0449
Retail Transmission Rate – Line and Transformation Connection Service Rate – Interval Metered	\$/kW	1.7719
Wholesale Market Service Rate	\$/kWh	0.0052
Rural Rate Protection Charge	\$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	\$	0.25

Large Use

Service Charge	\$	13,247.54
Distribution Volumetric Rate	\$/kW	2.7937
Regulatory Asset Recovery	\$/kW	0.0143
Retail Transmission Rate – Network Service Rate – Interval Metered	\$/kW	2.1820
Retail Transmission Rate – Line and Transformation Connection Service Rate – Interval Metered	\$/kW	1.8924
Wholesale Market Service Rate	\$/kWh	0.0052
Rural Rate Protection Charge	\$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	\$	0.25

Standby Power – APPROVED ON AN INTERIM BASIS

Except for the Integrated Gas Recovery Services' Britannia Sanitary Landfill and the Greater Toronto Airport Authority that are identified separately, the Standby Charge will be applied for a month where standby power is not provided. The charge is applied to the contracted amount (e.g. nameplate rating of generation facility). Further servicing details are available in Enersource Hydro's Conditions of Service.

\$/kW 2.61

The Integrated Gas Recovery Services' ("IGRS") Britannia Sanitary Landfill generating facility ("BSL"):

In addition to its regular account's monthly Service Charge, Enersource Hydro will charge IGRS the General Service 50 to 499 kW Distribution Volumetric Charge applied to the monthly contract demand quantity, initially set at 400 kW. A variable overrun distribution rate equal to the General Service 50 to 499 kW Distribution Volumetric Charge is applied to each kilowatt of demand delivered by Enersource Hydro to IGRS's BSL generating facility in the current month that exceeds the contract demand quantity. Demand is measured by Enersource Hydro's meter at the interconnection of IGRS' BSL generating facility and Enersource Hydro's distribution system. A monthly administration charge of \$200 is applied to IGRS' account for the manual intervention by settlement staff in the billing process. Further servicing details are available in Enersource Hydro's Conditions of Service.

Enersource Hydro Mississauga Inc.

TARIFF OF RATES AND CHARGES

Effective May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2007-0523

The Greater Toronto Airport Authority ("GTAA"):

In addition to its regular account's monthly Service Charge, Enersource Hydro will charge GTAA the Large Use Distribution Volumetric Charge applied to the monthly gross metered load. A monthly administration charge of \$500 is applied to the GTAA's account for the manual intervention by settlement staff in the billing process. Further servicing details are available in Enersource Hydro's Conditions of Service.

Street Lighting

Service Charge (per connection)	\$	0.36
Distribution Volumetric Rate	\$/kW	2.7462
Regulatory Asset Recovery	\$/kW	0.2304
Retail Transmission Rate – Network Service Rate	\$/kW	1.4637
Retail Transmission Rate – Line and Transformation Connection Service Rate	\$/kW	1.3094
Wholesale Market Service Rate	\$/kWh	0.0052
Rural Rate Protection Charge	\$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	\$	0.25

Specific Service Charges

Customer Administration		
Arrears Certificate	\$	15.00
Request for other billing information	\$	15.00
Credit reference/credit check (plus credit agency costs)	\$	15.00
Credit reference/credit check (plus credit agency costs – General Service)	\$	25.00
Income tax letter	\$	15.00
Returned cheque (plus bank charges)	\$	12.50
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	\$	30.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable – Residential)	\$	20.00
Meter dispute charge plus Measurement Canada fees (if meter found correct)	\$	10.00
Special meter reads	\$	30.00
Interval meter request change	\$	40.00
Non-Payment of Account		
Late Payment - per month	%	1.50
Late Payment - per annum	%	19.56
Collection of account charge – no disconnection	\$	9.00
Disconnect/Reconnect at meter - during regular hours	\$	20.00
Disconnect/Reconnect at pole - during regular hours	\$	185.00
Disconnect/Reconnect at pole - after regular hours	\$	415.00
Temporary service install and remove – overhead – no transformer	\$	400.00
Specific Charge for Access to the Power Poles – per pole/year	\$	22.35
Allowances		
Transformer Allowance for Ownership - per kW of billing demand/month	\$/kW	(0.40)
Primary Metering Allowance for transformer losses – applied to measured demand and energy	%	(1.00)

LOSS FACTORS

Total Loss Factor – Secondary Metered Customer < 5,000 kW	1.0433
Total Loss Factor – Secondary Metered Customer > 5,000 kW	1.0145
Total Loss Factor – Primary Metered Customer < 5,000 kW	1.0328
Total Loss Factor – Primary Metered Customer > 5,000 kW	1.0045

Answer to VECC question 9 D

		2006 Budgeted Enersource Corporation costs	2006 Alloc %	2006 Budget Management fee allocated to Enersource Hydro	2006 Actual Enersource Corporation costs	2006 Alloc %	2006 Actual Management fee allocated to Enersource Hydro
Enersource Hydro Mississauga:							
Corporate Governance	Time Estimate	410	90.00%	369	434	90.00%	391
Executive Management and Communications	Time Estimate	2,330	90.00%	2,097	2,222	90.00%	2,000
Safety	Time Estimate	307	90.00%	276	924	90.00%	831
Human Resources	Headcount	802	88.00%	706	874	88.00%	769
Finance	Time Estimate	3,799	80.00%	3,039	3,108	80.00%	2,486
Purchasing	Time Estimate	152	90.00%	137	150	90.00%	135
Legal	Time Estimate	429	30.00%	129	175	30.00%	52
Enersource Hydro Charges	Historical	586	82.02%	481	793	85.00%	674
Capital Taxes	Historical	23	82.02%	23	17	85.00%	15
Other Expense/Financial Income/Other Income	Historical	691	82.02%	673	528	85.00%	449
Total Management Fee		<u>9,529</u>		<u>\$ 7,929</u>	<u>9,225</u>		<u>\$ 7,802</u>

ExB Sch3 Tab2 - Appendix A (Updated with Jan'05-Apr'07)

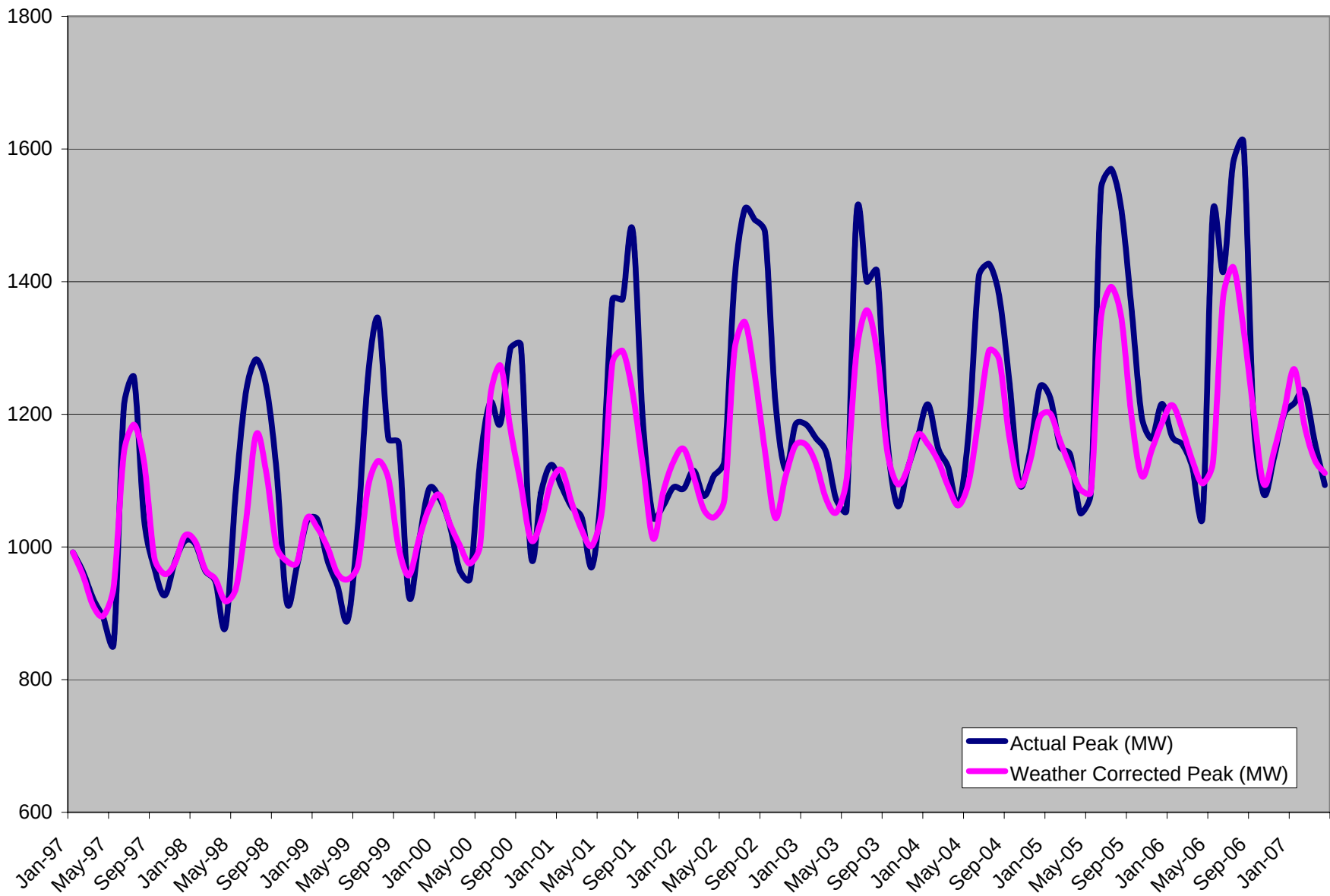
Trading Month	Actual Energy (MWh)	Weather Corrected Energy (MWh)	Weather Correction (MWh)		Actual Peak (MW)	Weather Corrected Peak (MW)	Weather Correction (MW)
Jan-97	591,610	590,006	-1,604		992	991.75	-0.25
Feb-97	523,702	527,801	4,100		962	956.34	-5.66
Mar-97	545,585	542,230	-3,355		922	910.93	-11.07
Apr-97	513,752	508,989	-4,764		893	896.34	3.34
May-97	504,262	507,362	3,100		854	940.13	86.13
Jun-97	558,780	528,907	-29,872		1,211	1,141.18	-69.82
Jul-97	604,731	599,456	-5,275		1,256	1,184.47	-71.53
Aug-97	558,571	575,001	16,430		1,041	1,127.03	86.03
Sep-97	516,623	515,330	-1,293		968	983.7	15.7
Oct-97	530,956	524,094	-6,862		927	959.1	32.1
Nov-97	547,008	538,899	-8,108		976	974.73	-1.27
Dec-97	576,496	581,483	4,987		1,009	1,017.23	8.23
Jan-98	585,118	600,767	15,649		1,005	1,008.88	3.88
Feb-98	523,095	538,760	15,665		964	966	2
Mar-98	570,073	572,179	2,106		948	951.39	3.39
Apr-98	505,489	512,983	7,495		880	917.98	37.98
May-98	537,853	518,021	-19,832		1,084	936.97	-147.03
Jun-98	582,393	552,061	-30,331		1,234	1,038.81	-195.19
Jul-98	629,387	615,393	-13,994		1,283	1,169.64	-113.36
Aug-98	633,247	596,845	-36,402		1,242	1,111.96	-130.04
Sep-98	562,308	534,713	-27,595		1,116	1,001.02	-114.98
Oct-98	534,822	538,805	3,983		917	978.76	61.76
Nov-98	551,434	554,989	3,555		970	976.08	6.08
Dec-98	578,814	592,818	14,004		1,039	1,043.45	4.45
Jan-99	600,424	606,536	6,113		1,042	1,029.05	-12.95
Feb-99	529,880	545,959	16,079		980	999.95	19.95
Mar-99	570,446	579,987	9,541		941	959.91	18.91
Apr-99	512,921	524,160	11,240		890	951.1	61.1
May-99	536,202	529,427	-6,775		1,032	971.83	-60.17
Jun-99	620,353	572,299	-48,054		1,259	1,091.43	-167.57
Jul-99	687,947	619,945	-68,002		1,344	1,129.94	-214.06
Aug-99	611,838	608,828	-3,010		1,163	1,102.77	-60.23
Sep-99	573,254	547,666	-25,588		1,157	999.46	-157.54
Oct-99	547,026	548,861	1,835		926	957.22	31.22
Nov-99	561,078	569,948	8,870		1,008	1,011.63	3.63
Dec-99	619,204	617,121	-2,083		1,088	1,058.42	-29.58
Jan-00	629,285	632,324	3,039		1,074	1,078.52	4.52
Feb-00	583,255	590,826	7,571		1,034	1,036.10	2.1
Mar-00	585,126	602,215	17,089		965	1,002.96	37.96
Apr-00	540,107	539,457	-650		952	974.98	22.98
May-00	572,602	559,734	-12,868		1,129	1,002.28	-126.72
Jun-00	595,751	589,098	-6,653		1,218	1,226.63	8.63
Jul-00	628,485	647,989	19,504		1,186	1,273.56	87.56
Aug-00	652,999	635,220	-17,780		1,300	1,176.54	-123.46
Sep-00	589,437	568,356	-21,081		1,305	1,094.94	-210.06
Oct-00	576,968	576,146	-822		986	1,010.56	24.56

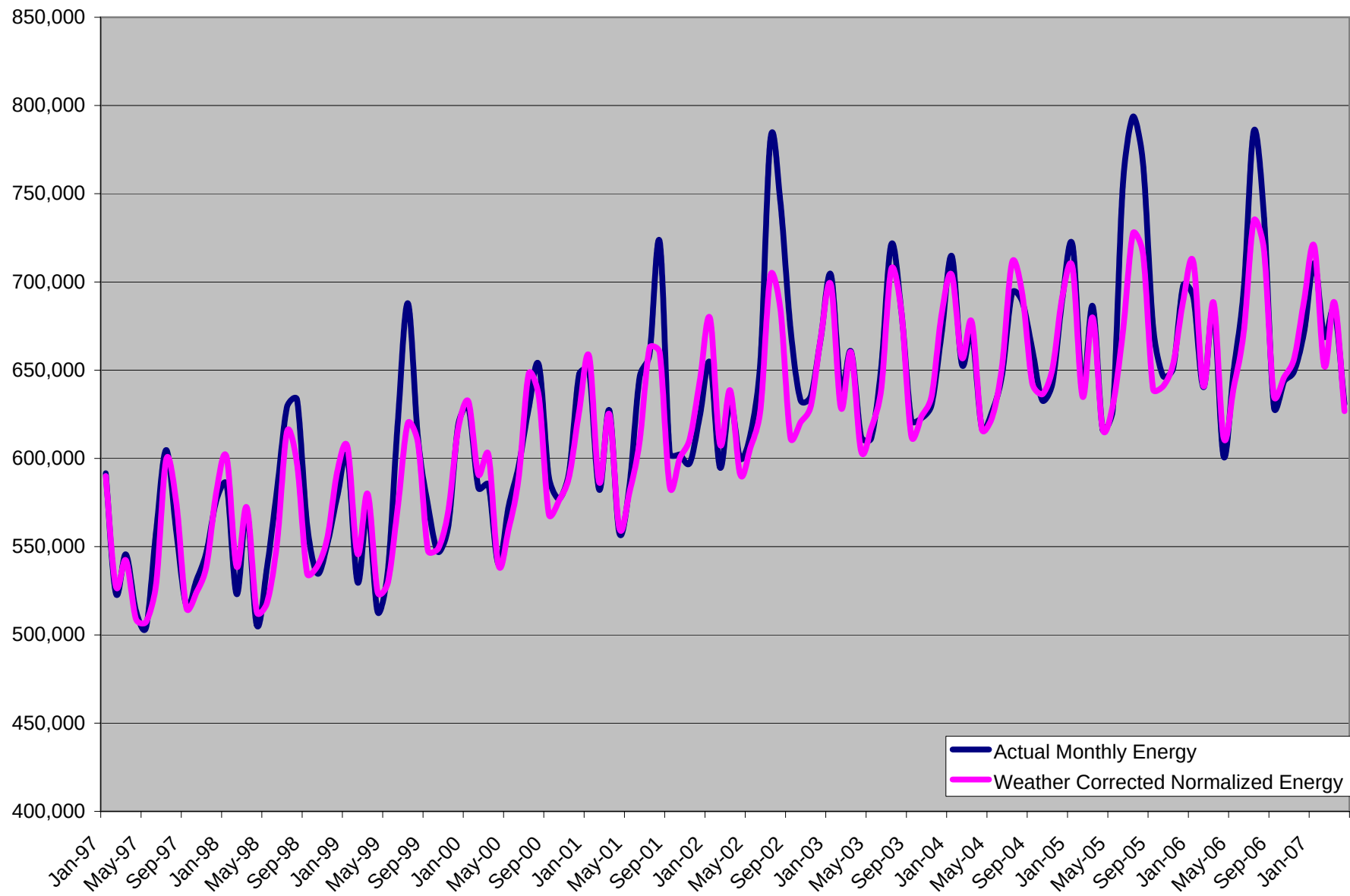
ExB Sch3 Tab2 - Appendix A (Updated with Jan'05-Apr'07)

Trading Month	Actual Energy (MWh)	Weather Corrected Energy (MWh)	Weather Correction (MWh)		Actual Peak (MW)	Weather Corrected Peak (MW)	Weather Correction (MW)
Nov-00	592,190	589,548	-2,642		1,082	1,039.31	-42.69
Dec-00	647,661	626,671	-20,990		1,124	1,098.32	-25.68
Jan-01	649,509	657,965	8,456		1,091	1,115.88	24.88
Feb-01	582,294	586,496	4,201		1,060	1,066.73	6.73
Mar-01	627,174	625,154	-2,020		1,044	1,025.30	-18.7
Apr-01	557,728	560,575	2,847		970	1,001.86	31.86
May-01	584,419	580,656	-3,763		1,105	1,058.03	-46.97
Jun-01	645,564	609,339	-36,225		1,373	1,277.60	-95.4
Jul-01	659,492	662,802	3,309		1,373	1,295.85	-77.15
Aug-01	722,902	659,988	-62,914		1,477	1,231.79	-245.21
Sep-01	602,684	584,047	-18,637		1,189	1,122.78	-66.22
Oct-01	602,304	600,165	-2,138		1,045	1,012.40	-32.6
Nov-01	597,480	611,197	13,717		1,062	1,082.81	20.81
Dec-01	624,215	644,378	20,163		1,090	1,128.32	38.32
Jan-02	654,337	679,473	25,136		1,088	1,148.05	60.05
Feb-02	594,862	607,992	13,130		1,115	1,105.26	-9.74
Mar-02	632,565	638,560	5,995		1,077	1,056.27	-20.73
Apr-02	599,937	590,917	-9,020		1,108	1,044.72	-63.28
May-02	613,199	605,904	-7,295		1,130	1,071.26	-58.74
Jun-02	654,990	627,324	-27,666		1,402	1,297.12	-104.88
Jul-02	781,059	703,735	-77,324		1,509	1,339.59	-169.41
Aug-02	745,061	684,396	-60,665		1,493	1,257.97	-235.03
Sep-02	673,569	611,588	-61,981		1,474	1,143.51	-330.49
Oct-02	632,948	620,559	-12,389		1,221	1,043.85	-177.15
Nov-02	635,185	629,365	-5,820		1,117	1,105.26	-11.74
Dec-02	668,269	668,534	264		1,185	1,153.44	-31.56
Jan-03	704,264	698,462	-5,802		1,185	1,154.47	-30.53
Feb-03	639,371	628,694	-10,677		1,164	1,125.33	-38.67
Mar-03	660,612	660,134	-478		1,143	1,072.71	-70.29
Apr-03	612,394	604,123	-8,271		1,071	1,052.07	-18.93
May-03	611,207	616,952	5,745		1,055	1,100.94	45.94
Jun-03	651,350	638,882	-12,468		1,505	1,296.12	-208.88
Jul-03	721,223	707,202	-14,021		1,400	1,356.95	-43.05
Aug-03	683,386	683,386	0		1,416	1,294.35	-121.65
Sep-03	621,515	612,468	-9,047		1,164	1,144.62	-19.38
Oct-03	622,719	623,829	1,110		1,062	1,094.90	32.9
Nov-03	630,346	635,281	4,935		1,117	1,117.82	0.82
Dec-03	670,992	681,827	10,835		1,165	1,168.85	3.85
Jan-04	714,721	704,065	-10,656		1,215	1,154.92	-60.08
Feb-04	653,440	657,097	3,658		1,149	1,129.70	-19.3
Mar-04	671,008	677,347	6,339		1,120	1,090.95	-29.05
Apr-04	617,241	616,539	-702		1,064	1,062.58	-1.42
May-04	626,305	622,928	-3,377		1,173	1,097.23	-75.77
Jun-04	647,295	652,357	5,061		1,408	1,195.32	-212.68
Jul-04	693,708	711,214	17,507		1,427	1,295.59	-131.41
Aug-04	689,041	693,365	4,324		1,379	1,282.52	-96.48

ExB Sch3 Tab2 - Appendix A (Updated with Jan'05-Apr'07)

Trading Month	Actual Energy (MWh)	Weather Corrected Energy (MWh)	Weather Correction (MWh)		Actual Peak (MW)	Weather Corrected Peak (MW)	Weather Correction (MW)
Sep-04	661,780	642,474	-19,306		1,250	1,165.83	-84.17
Oct-04	632,872	636,362	3,490		1,095	1,093.64	-1.36
Nov-04	642,602	650,927	8,325		1,141	1,127.05	-13.95
Dec-04	690,656	692,021	1,365		1,241	1,195.72	-45.28
Jan-05	721,089	708,305	-12,784		1,226	1,201	-24.18
Feb-05	639,696	635,043	-4,653		1,151	1,159	7.74
Mar-05	686,331	679,773	-6,558		1,139	1,120	-18.22
Apr-05	616,175	616,519	344		1,050	1,086	35.75
May-05	627,752	630,091	2,339		1,081	1,083	1.8
Jun-05	755,352	671,881	-83,471		1,539	1,345	-193.62
Jul-05	793,725	727,505	-66,220		1,570	1,392	-177.8
Aug-05	766,859	715,748	-51,111		1,510	1,347	-163.06
Sep-05	674,409	639,131	-35,278		1,360	1,198	-162.38
Oct-05	646,612	640,827	-5,785		1,197	1,107	-89.71
Nov-05	651,141	653,676	2,535		1,163	1,146	-17.11
Dec-05	698,177	689,635	-8,543		1,216	1,187	-28.89
Jan-06	691,196	711,284	20,088		1,166	1,214	47.77
Feb-06	640,324	640,986	662		1,154	1,177	22.52
Mar-06	684,235	688,284	4,049		1,119	1,130	10.34
Apr-06	601,033	611,704	10,671		1,047	1,096	48.97
May-06	650,016	640,101	-9,916		1,505	1,127	-377.83
Jun-06	696,320	671,914	-24,406		1,415	1,376	-38.93
Jul-06	785,520	734,666	-50,854		1,580	1,422	-157.74
Aug-06	738,477	718,763	-19,714		1,610	1,331	-279.68
Sep-06	629,090	635,322	6,232		1,191	1,204	12.88
Oct-06	643,496	645,952	2,456		1,079	1,095	15.59
Nov-06	649,379	656,538	7,158		1,134	1,144	10.16
Dec-06	671,891	689,818	17,927		1,200	1,205	4.63
Jan-07	710,693	720,267	9,574		1,217	1,268	51.2
Feb-07	669,195	652,353	-16,842		1,235	1,183	-51.4
Mar-07	683,992	688,433	4,441		1,160	1,132	-27.78
Apr-07	630,838	626,800	-4,038		1,093	1,111	18.17





VECC#11

Economic Drivers for the City of Mississauga Used for Enersource's Short Term Load Forecast

Year	Population	Total Employment	Employment Land Related	Employment Population Related	Employment Office Related	Total Housing
1996	563,785	340,102	195,167	85,529	59,406	173,809
1997	582,164	346,873	198,696	88,158	60,019	178,691
1998	599,809	355,251	203,181	90,725	61,345	183,762
1999	616,587	364,831	208,355	93,213	63,263	188,775
2000	632,384	375,229	213,966	95,603	65,661	193,700
2001	647,105	386,143	219,812	97,887	68,444	198,525
2002	660,677	397,239	225,679	100,045	71,515	203,206
2003	673,047	408,266	231,401	102,069	74,796	207,723
2004	684,182	418,987	236,827	103,949	78,211	212,044
2005	694,068	429,246	241,853	105,683	81,710	216,155
2006	702,714	438,857	246,365	107,260	85,233	220,016
2007	710,146	447,718	250,297	108,680	88,741	223,604
2008	716,414	455,741	253,600	109,941	92,200	226,890
2009	721,584	461,644	255,838	111,386	94,420	229,855
2010	725,746	466,267	257,201	112,183	96,883	232,464

Housing Detached	Housing Semi	Housing Appartments + Condominiums	Housing Town
75,815	22,342	50,857	24,794
78,635	23,177	51,761	25,118
81,264	24,026	52,794	25,678
83,702	24,793	53,860	26,421
85,941	25,483	54,963	27,313
87,986	26,104	56,111	28,323
89,824	26,661	57,307	29,414
91,455	27,160	58,557	30,551
92,871	27,607	59,864	31,701
94,075	28,011	61,238	32,831
95,056	28,375	62,680	33,905
95,812	28,706	64,196	34,890
96,340	29,011	65,790	35,749
96,635	29,296	67,472	36,452
96,693	29,567	69,243	36,962

Energy Consumption Forecast

Regression Statistics	
Iterations	8
Adjusted Observations	4125
Deg. of Freedom for Error	4051
R-Squared	0.975
Adjusted R-Squared	0.974
Durbin-Watson Statistic	2.051
Durbin-H Statistic	#NA
AIC	12.285
BIC	12.398
F-Statistic	2119.494
Prob (F-Statistic)	0
Log-Likelihood	-31108.61
Model Sum of Squares	33334003258
Sum of Squared Errors	860965627
Mean Squared Error	212531.63
Std. Error of Regression	461.01
Mean Abs. Dev. (MAD)	304.57
Mean Abs. % Err. (MAPE)	1.53%
Ljung-Box Statistic	186.29
Prob (Ljung-Box)	0

Statistical Correlation Report (Energy Consumption)

Input/Output	Energy
Population	0.587
TWT	0.331
Monday	0.090
Friday	0.094
Saturday	-0.278
OfficeHolidays	-0.084
RetailHolidays	-0.136
Employment	0.580
AveDB	0.100
AveDBSquared	0.346
AveDBCubed	0.366
BuildUp	0.092
MaxDB	0.097
MinDB	0.103
CumHi	0.092
CumLo	0.089
CDD	0.423
XCDD	0.445
HDD	0.100
XHDD	0.154
AveDBWkEnd	-0.282
CDDWkEnd	-0.063
XCDDWkEnd	0.074
HDDWkEnd	-0.212
XHDDWkEnd	-0.072
BuildUpWkEnd	-0.287
CumHiWkEnd	-0.312
CumLoWkEnd	-0.173
LaggHDD	0.094
LaggCDD	0.394
NightDB	0.098
MornDB	0.101
AfterDB	0.092
EvenDB	0.098
NightHDD	0.099
MornHDD	0.081
AfterHDD	0.122
EvenHDD	0.099
MornCDD	0.451
AfterCDD	0.348
EvenCDD	0.118
NightCDD	0.376
HoursOfLight	0.023

Statistical Correlation Report (Energy Consumption)

Input/Output	Energy
FractionOfDarkHour6	-0.048
FractionOfDarkHour7	-0.012
FractionOfDarkHour8	0.027
FractionOfDarkHour17	0.011
FractionOfDarkHour18	0.054
FractionOfDarkHour19	-0.005
FractionOfDarkHour20	-0.068
FractionOfDarkHour21	-0.149
Jan	0.078
Feb	0.070
Mar	-0.028
Apr	-0.154
May	-0.173
Jun	0.067
Jul	0.186
Aug	0.139
Sept	-0.027
Oct	-0.138
Nov	-0.040
JanWkDay	0.141
FebWkDay	0.131
MarWkDay	0.058
AprWkDay	-0.049
MayWkDay	-0.061
JunWkDay	0.146
JulWkDay	0.248
AugWkDay	0.213
SeptWkDay	0.053
OctWkDay	-0.038
NovWkDay	0.044

Peak Demand Forecast

Regression Statistics	
Iterations	1
Adjusted Observations	3850
Deg. of Freedom for Error	3769
R-Squared	0.965
Adjusted R-Squared	0.964
Durbin-Watson Statistic	2.033
Durbin-H Statistic	-
AIC	6.718
BIC	6.849
F-Statistic	1302.649
Prob (F-Statistic)	0
Log-Likelihood	-18313.56
Model Sum of Squares	84402352
Sum of Squared Errors	3052554
Mean Squared Error	809.91
Std. Error of Regression	28.46
Mean Abs. Dev. (MAD)	19.53
Mean Abs. % Err. (MAPE)	2.04%
Ljung-Box Statistic	140.04
Prob (Ljung-Box)	0

Forecast Statistics	
Forecast Observations	273
Mean Abs. Dev. (MAD)	21.07
Mean Abs. % Err. (MAPE)	2.08%
Avg. Forecast Error	-9.55
Mean % Error	-1.03%
Root Mean-Square Error	543.561
Theil's Inequality Coefficient	0.0155
Bias Proportion	8.43%
Variance Proportion	2.39%
Covariance Proportion	89.19%

Statistical Correlation Report (Peak Demand)

Input/Output	Peak
Population	0.529
TWT	0.322
Monday	0.117
Friday	0.082
Saturday	-0.31
TimeTrend	-0.511
RetailHolidays	-0.136
OfficeHolidays	-0.069
HousingUnits	0.528
Employment	0.524
AveDB	0.226
AveDBSquared	0.46
AveDBCubed	0.486
BuildUp	0.214
MaxDB	0.224
MinDB	0.225
CumHi	0.214
CumLo	0.209
CDD	0.535
XCDD	0.507
HDD	-0.002
XHDD	0.078
AveDBWkEnd	-0.269
CDDWkEnd	-0.048

XCDDWkEnd	0.09
HDDWkEnd	-0.225
XHDDWkEnd	-0.089
BuildUpWkEnd	-0.278
CumHiWkEnd	-0.303
CumLoWkEnd	-0.164
AveDwPt	0.22
AveDwPtCubed	0.305
LaggHDD	-0.012
LaggCDD	0.491
NightDB	0.22
MornDB	0.227
AfterDB	0.217
EvenDB	0.22
NightHDD	0.005
MornHDD	-0.026
AfterHDD	0.031
EvenHDD	0.005
MornCDD	0.554
AfterCDD	0.472
EvenCDD	0.071
NightCDD	0.489
HoursOfLight	0.099
FractionOfDarkHour6	-0.124
FractionOfDarkHour7	-0.071
FractionOfDarkHour8	0.003
FractionOfDarkHour17	0.019
FractionOfDarkHour18	0.019
FractionOfDarkHour19	-0.096
FractionOfDarkHour20	-0.157
FractionOfDarkHour21	-0.236
Jan	0.047
Feb	0.006
Mar	-0.091
Apr	-0.185
May	-0.161
Jun	0.118
Jul	0.249
Aug	0.172
Sept	0.003
Oct	-0.155
Nov	-0.036
JanWkDay	0.104
FebWkDay	0.067
MarWkDay	-0.005
AprWkDay	-0.078
MayWkDay	-0.041
JunWkDay	0.203
JulWkDay	0.317
AugWkDay	0.254
SeptWkDay	0.084

OctWkDay	-0.057
NovWkDay	0.041
WkDay	0.507
WkEnd	-0.507



RP-2004-0069

EB-2004-0055

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

AND IN THE MATTER OF an Application by Enersource
Hydro Mississauga Inc. for an order or orders approving or
fixing just and reasonable rates.

BEFORE:

Bob Betts
Presiding Member

Paul Vlahos
Member

DECISION AND ORDER

On January 15, 2004 the Ontario Energy Board (“the Board”) issued filing guidelines to all electricity distribution utilities for distribution rate adjustments related to the recovery of Regulatory Assets, to be effective March 1, 2004 and implemented on April 1, 2004.

The Applicant filed an application for such adjustment. Notice of the proceeding was published on February 5, 2004 in major newspapers in the province.

The Applicant also applied for recovery of amounts outside of the guidelines. Specifically, the Applicant requested that amounts pertaining to 2001 Q4 Payments in Lieu of Taxes not be removed when setting 2004 distribution rates. In his letter to the Board authorizing the Board to proceed with allowing the recovery of Regulatory Assets, the Minister of Energy requested that the Board report on any anomalies in the applications. At this time, the Board will approve only the portion of the application that conforms to the guidelines. The Applicant’s other request will be reported as an anomaly to the Minister along with the Board’s recommendation regarding this part of the Applicant’s proposal.

While the Board had originally intended to approve the disposal of RSVA amounts on a final basis, on analysis of the applications by distributors and the reporting of RSVA amounts in these applications, the Board has now determined that all rate changes should be interim. In the Board's view, it would be premature to set these rates final based on the quality of the data contained in many of the applications and the fact that the audit sampling process by the Board has not been completed.

The Board received some interventions in these proceedings, mainly concerned with Phase Two of the process. The only intervenor to make specific submissions on Phase One of the proceeding was the School Energy Coalition, ("SEC") who objected to any interim increase in rates over and above the RSVA amounts on the basis that appropriate evidence had not been filed on these amounts. The Board is not convinced by SEC's arguments and sees no reason that Phase One cannot proceed. Phase One only contemplates partial recovery on an interim basis at this time. In Phase Two, the Board will review all applications to ensure that only prudent and reasonably incurred costs are recovered over the four year period mandated by the Minister.

In light of the above, the Board finds that it is in the public interest to order as follows.

THE BOARD ORDERS THAT:

- 1 The rate schedule attached is approved on an interim basis, effective March 1, 2004, to be implemented on April 1, 2004. All other rates currently in effect that are not shown on the attached schedule remain in force. If the Applicant's billing system is not capable of prorating to accommodate the April 1, 2004 implementation date, the new rates shall be implemented with the first billing cycle for electricity taken or considered to have been taken from April 1, 2004.
- 2 The Applicant shall notify its customers of the rate changes by including the brochure provided by the Board through a different process, no later than with the first customer bill reflecting the new rates, and provide to the Board samples of any other notices sent by the Applicant to its customers with respect to the rate changes. The Board expects the Applicant to provide notice to all customers about the rate changes, no later than with the first bill reflecting the new rates.

DATED at Toronto, March 16, 2004.

ONTARIO ENERGY BOARD

Peter H. O'Dell
Assistant Secretary

2005																			2	
Account Description	Account Number	Opening Principal Amounts as of Jan-1-04 ¹	Transactions (additions) during 2004, excluding interest and adjustments ⁶	Closing Principal Balance as of Dec-31-04	Interest Jan-1 to Dec-31-04	Closing Principal Balance as of Dec-31-04	Opening Principal Amounts as of Jan-1-05 ¹	Transactions (additions) during 2005, excluding interest and adjustments ⁶	Transactions (reductions) during 2005, excluding interest and adjustments ⁶	Adjustments during 2005 - instructed by Board ²	Closing Principal Balance as of Dec-31-05	Opening Interest Amounts as of Jan-1-05	Interest Jan-1 to Dec-31-05	Closing Interest Amounts as of Dec-31-05	Opening Principal Amounts as of Jan-1-06	Transactions (additions) during 2006, excluding interest and adjustments ⁶	Transactions (reductions) during 2006, excluding interest and adjustments ⁶	Adjustments during 2006 - instructed by Board ²	Transfer of Board-approved amounts to 1590 as per 2006 EDR	
RSVA - Wholesale Market Service Charge	1580	\$0	\$(267,757)	\$(267,757)	\$(23,595)	\$(23,595)	\$(267,757)	\$ 5,587,753			\$ 5,319,996	\$ (23,595)	\$ 106,957	\$ 83,363	\$ 5,319,996	\$ (10,216,417)		\$ -	\$ 267,757	
RSVA - One-time Wholesale Market Service	1582	-	460,984	460,984	21,275	\$21,275	\$ 460,984	\$ 437,418			\$ 898,402	\$ 21,275	\$ 43,265	\$ 64,540	\$ 898,402	\$ -		\$ -	\$ (460,984)	
RSVA - Retail Transmission Network Charge	1584	-	1,713,447	\$(1,713,447)	-	57,140	\$(57,140)	\$(1,713,447)	\$ 1,765,581		\$ 52,134	\$(57,140)	\$ 35,084	\$(22,056)	\$ 52,134	\$ 1,358,422		\$ -	\$ -	
RSVA - Retail Transmission Connection Charge	1586	-	2,517,648	\$(2,517,648)	-	89,386	\$(89,386)	\$(2,517,648)	\$(562,736)		\$(3,080,384)	\$ (89,386)	\$(129,494)	\$(218,880)	\$(3,080,384)	\$ 676,484		\$ -	\$ -	
Sub-Totals		-	\$ (4,037,867)	\$(4,037,867)	\$ (148,845)	\$(148,845)	\$ (4,037,867)	\$ 7,228,016		\$ -	\$ 3,190,149	\$(148,845)	\$ 55,812	\$(93,033)	\$ 3,190,149	\$(8,181,511)		\$ -	\$ (193,227)	
Other Regulatory Assets - Sub-Account - OEB Cost Assessme	1508	-	424,709	\$424,709	10,223	\$10,223	\$ 424,709	\$ 687,860			\$ 1,112,568	\$ 10,223	\$ 41,998	\$ 52,221	\$ 1,112,568	\$ 214,119	\$ (127,231)			
Other Regulatory Assets - Sub-Account - Pension Contribution	1508	-	874,227	\$874,227		\$0	\$ 874,227	\$ 1,041,002			\$ 1,915,229	\$ -	\$ 48,948	\$ 48,948	\$ 1,915,229	\$ 330,735	\$(268,734)			
Other Regulatory Assets - Sub-Account - Other ¹	1508	-		\$0		\$0					\$ -			\$ -						
Other Regulatory Assets - Sub-Account - Other ¹	1508	-		\$0		\$0					\$ -			\$ -						
Other Regulatory Assets - Sub-Account - Other ¹	1508	-		\$0		\$0					\$ -			\$ -						
Retail Cost Variance Account - Retail	1518	-	8,224	\$8,224	262	\$262	\$ 8,224	\$ 65,403			\$ 73,627	\$ 262	\$ 2,260	\$ 2,521	\$ 73,627	\$ 41,202			\$ (8,223)	
Retail Cost Variance Account - STR	1548	-	51,395	\$51,395	1,005	\$1,005	\$ 51,395	\$ 87,436			\$ 138,831	\$ 1,005	\$ 6,390	\$ 7,396	\$ 138,831	\$ 85,578			\$ (51,395)	
Misc. Deferred Debits	1525	-	\$0			\$0	\$ -	\$ -			\$ -	\$ -	\$ -	\$ -	\$ -	\$ 21,095				
LV Variance Account (Note 1)	1550	-														\$ (218,851)				
RSVA - Power (including Global Adjustment)	1568	-	2,850,219	\$(2,850,219)	-	115,492	\$(115,492)	\$(2,850,219)	\$ (8,339,251)		\$(11,189,470)	\$(115,492)	\$(593,445)	\$(708,937)	\$(11,189,470)	\$ 9,470,216			\$ 2,850,219	
RSVA - Power - Sub-Account - Global Adjustment	1588	-						\$ (6,402,236)			\$ (6,402,236)		\$(334,123)	\$(334,123)		\$ 13,115,415				
2006 PILs & Taxes Variance	1592	-		\$0																
Recovery of Regulatory Asset Balances	1590	-	\$ (5,254,873)	\$(5,254,873)	-	115,426	\$(115,426)	\$(5,254,873)	\$ -	\$ (7,705,630)	\$ 29,845,816	\$ 16,885,313	\$(115,426)	\$ 892,285	\$ 776,859	\$ 16,885,313	\$ 388,262	\$(7,372,745)	\$(2,713,917)	
		\$ -	\$(10,784,405)	\$(10,784,405)	\$(368,273)	\$(368,273)	\$(10,784,405)	\$ (5,631,769)	\$ (7,705,630)	\$ 29,845,816	\$ 5,724,012	\$(368,273)	\$ 120,126	\$(248,147)	\$ 5,724,012	\$ 15,266,259	\$ (7,789,710)	\$(2,713,917)	\$ 2,597,373	

SHEET 1 - Regulatory Assets - Continuity Schedule

2006													
Account Number	Closing Principal Balance as of Dec-31-06	Opening Interest Amounts as of Jan-1-06	Interest Jan-1 to Dec31-06	Transfer of Board-approved amounts to 1590 as per 2006 EDR	Closing Interest Amounts as of Dec-31-06	Projected Interest on Dec 31 -06 balance from Jan 1, 2007 to Dec 31, 2007 ^a	Projected Interest on Dec 31 -06 balance from Jan 1, 2008 to April 30, 2008 ^a	Claim before Forecasted Transactions	Forecasted Transactions, Excluding Interest from Jan 1, 2007 to Dec 31, 2007	Forecasted Transactions, Excluding Interest from Jan 1, 2008 to April 30, 2008	Projected Interest from Jan 1, 2007 to April 30, 2008 on Forecasted Transx (Excl Interest) from Jan 1, 2007 to December 31, 2007	Projected Interest from Jan 1, 2008 to April 30, 2008 on Forecasted Transx (Excl Interest) from Jan 1, 2008 to April 30, 2008	Total Claim
Account Description													
RSVA - Wholesale Market Service Charge	1580	\$ (4,628,664)	\$ 83,363	\$ 76,815	\$ 23,595	\$ 183,773		\$ (4,444,891)					\$ (4,444,891)
RSVA - One-time Wholesale Market Service	1582	\$ 437,418	\$ 64,540	\$ 45,636	\$ (21,275)	\$ 88,902		\$ 526,320					\$ 526,320
RSVA - Retail Transmission Network Charge	1584	\$ 1,410,556	\$ (22,056)	\$ (6,962)	\$ -	\$ (29,018)		\$ 1,381,538					\$ 1,381,538
RSVA - Retail Transmission Connection Charge	1586	\$ (2,403,900)	\$ (218,880)	\$ (179,336)	\$ -	\$ (398,216)		\$ (2,802,116)					\$ (2,802,116)
Sub-Totals		\$ (5,184,590)	\$ (93,033)	\$ (63,847)	\$ 2,320	\$ (154,559)	\$ - \$ -	\$ (5,339,149)	\$ - \$ -	\$ - \$ -	\$ - \$ -	\$ -	\$ (5,339,149)
Other Regulatory Assets - Sub-Account - OEB Cost Assessme	1508	\$ 1,199,457	\$ 52,221	\$ 60,594		\$ 112,815	\$ 55,055 \$ 18,352	\$ 1,385,678	\$ (187,872)	\$ (68,896)	\$ (3,965)	\$ (3,248)	\$ 1,121,697
Other Regulatory Assets - Sub-Account - Pension Contribution	1508	\$ 1,956,230	\$ 48,948	\$ 89,101		\$ 138,049	\$ 89,791 \$ 29,930	\$ 2,214,000	\$ (431,708)	\$ (152,660)	\$ (9,086)	\$ (7,456)	\$ 1,613,090
Other Regulatory Assets - Sub-Account - Other ^a	1508	\$ -	\$ -		\$ -	\$ -		\$ -					\$ -
Other Regulatory Assets - Sub-Account - Other ^a	1508	\$ -	\$ -		\$ -	\$ -		\$ -					\$ -
Other Regulatory Assets - Sub-Account - Other ^a	1508	\$ -	\$ -		\$ -	\$ -		\$ -					\$ -
Retail Cost Variance Account - Retail	1518	\$ 106,605	\$ 2,521	\$ 5,134	\$ (262)	\$ 7,393		\$ 113,999					\$ 113,999
Retail Cost Variance Account - STR	1548	\$ 173,014	\$ 7,396	\$ 9,314	\$ (1,005)	\$ 15,704		\$ 188,718					\$ 188,718
Misc. Deferred Debits	1525	\$ 21,095	\$ -		\$ 762	\$ 762	\$ 968 \$ 323	\$ 23,147	\$ -	\$ -	\$ -	\$ -	\$ 23,147
LV Variance Account (Note 1)	1550	\$ (218,851)		\$ (2,847)		\$ (2,847)		\$ (221,698)					\$ (221,698)
RSVA - Power (including Global Adjustment)	1588	\$ 1,130,965	\$ (708,937)	\$ (259,792)	\$ 115,492	\$ (853,238)		\$ 277,728					\$ 277,728
RSVA - Power - Sub-Account - Global Adjustment	1588	\$ 6,713,179	\$ (334,123)	\$ 148,350		\$ (185,773)		\$ 6,527,406					\$ 6,527,406
2006 PILs & Taxes Variance	1592												\$ (30,477)
Recovery of Regulatory Asset Balances	1590	\$ 7,186,913	\$ 776,859	\$ 680,746		\$ 1,457,605	\$ 302,515 \$ 100,838	\$ 9,047,872	\$ (5,392,170)	\$ (1,927,904)	\$ (102,570)	\$ (87,807)	\$ 1,537,421
		\$ 13,084,017	\$ (248,147)	\$ 666,753	\$ 117,307	\$ 535,912	\$ 448,329 \$ 149,443	\$ 14,217,701	\$ (6,011,750)	\$ (2,149,460)	\$ (115,621)	\$ (98,511)	\$ 5,811,882

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RCVA and RSVA's Accounts

Retail Cost Variances (RCVAs)

	Principal	Interest	Total
1518 RCVA Retail	106,705	7,396	114,101
1548 RCVA STR	173,014	15,704	188,718
Total Retail Cost Variances Accounts	279,719	23,100	302,819

Retail Settlement Variances (RSVAs)

1580 RSVA WHMS	(4,628,663)	183,772	(4,444,891)
1582 RSVA WHMS - One Time	437,418	88,902	526,320
1584 RSVA Network	1,410,556	(29,018)	1,381,538
1586 RSVA Connection	(2,403,900)	(398,216)	(2,802,116)
1588 RSVA Power (Excluding Global Adjustment)	(5,582,213)	(667,465)	(6,249,678)
Total Retail Settlement Variances Accounts	(10,766,802)	(822,025)	(11,588,827)

Other Regulatory Assets

1508 Sub Account - OEB Assessed Costs	942,688	179,009	1,121,697
1508 Sub Account - OMERS Pension Costs	1,371,737	241,353	1,613,090
Total Other Regulatory Asset Accounts	2,314,425	420,362	2,734,787
	(8,172,658)	(378,563)	(8,551,221)

Note: Please refer to Continuity Schedule provided under IR #25 (c) for details on the above accounts



2006 COST ALLOCATION INFORMATION FILING

Enersource Hydro Mississauga

EB-2005-0360 EB-2006-0247

Monday, January 15, 2007

Sheet 02 Monthly Fixed Charge Min. & Max. Worksheet - First Run

Output sheet showing minimum and maximum level for
Monthly Fixed Charge

Summary

Customer Unit Cost per month - Avoided Cost

Customer Unit Cost per month - Directly Related

Customer Unit Cost per month - Minimum System
with PLCC Adjustment

Fixed Charge per approved 2006 EDR

1	2	3	4	5	6	7
Residential	Small Commercial	GS < 50kW	GS 50 - 499kW	GS 500 - 4999kW	Large User > 5MW	Street Light
\$1.21	\$0.73	\$5.51	\$21.74	\$23.34	\$59.26	\$0.39
\$1.80	\$1.18	\$7.15	\$28.18	\$32.08	\$77.65	\$0.84
\$14.67	\$13.32	\$33.99	\$60.91	\$147.23	\$202.91	\$12.72
\$11.31	\$14.29	\$28.84	\$72.96	\$1,234.56	\$13,190.70	\$0.36