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Supporting Material – Excel Models:

- RSL 2012 Revenue Requirement Model MIFRS
- RSL 2012 Filing_Requirements_Chapter2_Appendices
- RSL 2012_RTSR_Adjustment_Work_Form
- RSL 2012_Rev_Reqt_Work_Form
- RSL 2012_CA_Model_version_2 (No paper copy submitted)
- RSL 2012_Test_year_Income_Tax_PILs_Workform
- RSL 2012 Exhibit 11 SM Model V2.17
- RSL 2012 Exhibit 9 EDVAR Continuity Schedule (no paper copy submitted)
- RSL 2012 EDVAR Rider Calculation

ONTARIO ENERGY BOARD

IN THE MATTER OF the Ontario Energy Board Act, 1998, being Schedule B to the Energy Competition Act, 1998, S.O. 1998, c.15;

AND IN THE MATTER OF an Application by Rideau St. Lawrence Distribution Inc. to the Ontario Energy Board for an Order or Orders approving or fixing just and reasonable rates and other service charges for the distribution of electricity as of May 1, 2012.

2.0 APPLICATION

The Applicant is Rideau St. Lawrence Distribution Inc.("RSL"), a licensed distributor in the Province of Ontario ED-2003-0003. Rideau St. Lawrence Distribution Inc. is an Ontario Corporation with its head office in the Town of Prescott. Rideau St. Lawrence Distribution Inc. carries on the business of distributing electricity within the Town of Prescott, and within the Villages of Cardinal, Iroquois, Morrisburg, Westport, and Williamsburg.

Rideau St. Lawrence Distribution Inc. hereby applies to the Ontario Energy Board (the "OEB") pursuant to section 78 of the Ontario Energy Board Act, 1998 for approval of its proposed distribution rates and other charges, effective May 1, 2012.

Except where specifically identified in the Application, the Applicant followed Chapter 2 of the Filing Requirements for Transmission and Distribution Applications dated June 22, 2011 (the "Filing Requirements") in order to prepare this application.

In accordance with the Board letter of March 15, 2011 with respect to the "Use of Modified IFRS as a Basis for Filing Cost of Service Applications for 2012 Rates, RSL has prepared this Application under the Boards Modified IFRS (MIFRS) approach.

The Schedule of Rates and Charges proposed in this Application is shown as Attachment 1A, in Exhibit 1.

Rideau St. Lawrence Distribution Inc. (RSL) requests that the OEB make its Rate Order effective May 1, 2012 in accordance with the Filing Requirements. RSL understands that due to filing this application late, the proposed rates may not be approved in time to implement them on May 1, 2012. RSL would request that the Board approve RSL's existing rates as interim rates effective May 1, 2012 subject to a final order, or that the Board approval for rates effective May 1 2012, are to be implemented in such a way that Rideau recovers revenues with in the 2012 Rate Year.

Rideau St. Lawrence Distribution Inc. submits the proposed distribution rates contained in this Application are just and reasonable on the following grounds:

(i) the proposed rates for the distribution of electricity have been prepared in accordance with the Filing Requirements;

(ii) the proposed adjusted rates are necessary to meet Rideau St. Lawrence Distribution Inc.'s Market Based Rate of Return and PILs requirements;

(iii) there are no impacts to any of the customer classes or consumption level subgroups that are so significant as to warrant the deferral of any adjustments being requested by Rideau St. Lawrence Distribution Inc.; and

(iv) other grounds as may be set out in the material accompanying this Application Summary.

Rideau St. Lawrence Distribution Inc. applies for an Order or Orders approving the proposed distribution rates and other charges set out in this Application to be effective May 1, 2012. The Applicant submits these rates and charges are just and reasonable pursuant to section 78 of the Ontario Energy Board Act, 1998 being Schedule B to the Energy Competition Act, 1998, S.O. 1998, c.15,

The address of service for the Applicant is:
985 Industrial Road
Prescott, ON
K0E 1T0

DATED at Prescott, Ontario, this 7th day of February, 2012.

Rideau St. Lawrence Distribution Inc.

John Walsh
President and CEO

____
Signature

Allan Beckstead
CFO

____

Signature

Historically RSL has published the application information in the weekly local newspapers from our service territory, and RSL would like to continue that process.

All the newspapers listed below are paid publications:

- The Morrisburg Leader – distribution of 2,100, covering Morrisburg, Williamsburg, and Iroquois,
- The Prescott Journal – distribution of 2,600 for Prescott, Cardinal, and the surrounding area.
- The Westport Review Mirror – distribution of 1,944 for Westport and the surrounding area.

3.0 CONTACT INFORMATION

TITLE: CFO	Phone: 613-925-3851
NAME: Allan Beckstead	Fax: 613-925-0303
	E-mail: abeckstead@rslu.ca
TITLE: President and CEO	Phone: 613-925-3851
NAME: John Walsh	Fax: 613-925-0303
	E-mail: jwalsh@rslu.ca
TITLE: Operations Manager	Phone: 613-925-3851
NAME: John Biccum	Fax: 613-925-0303
	E-mail: jbiccum@rslu.ca

4.0 SPECIFIC APPROVALS REQUESTED

In this proceeding, Rideau St. Lawrence Distribution Inc. requests the following specific approvals:

- Approval of interim rates effective May 1, 2012 subject to final approval if, due to the late filing by Rideau St. Lawrence, the proposed are not approved in time for May 1'st 2012 implementation, or the ability to recover the rates proposed herein in the 2012 rate year.
- Approval to charge rates effective May 1, 2012 to recover a Service Revenue Requirement of $2,735,672 which includes a revenue deficiency of $570,329 as set out in Exhibit 6. The schedule of proposed rates is set out in Exhibit 1 Appendix 1A, and in Exhibit 8; and
- Approval of the proposed Total Loss Factor as set out in Exhibit 8; and
- Approval of revised low voltage rates to be included in the standard distribution rates as proposed and described in Exhibit 8; and
- Approval to revise a Retail Transmission Network Service rate and a Retail Transmission Connection Rate as proposed and described in Exhibit 8; and
- Approval to continue to charge Wholesale Market and Rural Rate Protection Charges approved in the OEB Decision and Order in the matter of RSL's 2011 Distribution Rates (EB-2010-0113); and
- Approval to continue the Specific Service Charges and Transformer Allowance approved in the OEB Decision and Order in the matter of RSL's 2011 Distribution Rates (EB-2011-0113); and
- Approval to re-align the Revenue to Cost ratios as detailed in Exhibit 7; and
- Approval to discontinue the Smart Meter rate adder; and
- Approval to recover amounts associated with the true-up of Revenue Requirement as it relates to Smart Meters, using the method of recovery described in Exhibit 11; and
- Approval to setup accounts 1555 – Stranded Meters, and Recovery Offset Variance Account, 1555- Stranded Meters Recovery Offset Variance. Stranded Meter Assets of Capital cost of $295,772, less accumulated depreciation of $115,330 (NBV) were removed from our rate base effective December 31, 2011, a Rate Rider was requested to recover the stranded asset NBV of $180,442, for

the Residential and Commercial meters, replaced by the Smart meters, before the end of their useful life.

- Approval to recover amounts related to Lost Revenue Adjustment Mechanism ("LRAM") activities for 2010 over a one year period, using the method of recovery described in Exhibit 9; and

- Approval to continue account 1521 – Special Purpose Charge (SPC) Assessment Variance, until such time as an audited balance can be requested for disposition as described in Exhibit 9; and

- Approval of RSL's Basic Green Energy Plan; and

- Approval to dispose of the balances, as at December 31, 2010, of the following Deferral and Variance Accounts over a one year period using the method of recovery described in Exhibit 9; and

  1508 Other Regulatory Assets – Sub – account Hydro One Incremental Capital
  1508 Other Regulatory Assets – Sub – account – OEB Cost Assessments
  1518 Retail Cost Variance Account
  1548 Retail Cost Variance Account (STR)
  1550 Low Voltage Variance
  1562 Deferred Payment in Lieu of Taxes
  1580 RSVA - Wholesale Market Service Charges
  1584 RSVA - Transmission Network
  1586 RSVA - Transmission Connection
  1588 RSVA - Power (excluding Sub-account Global Adjustment)
  1588 RSVA – Power Sub Account Global Adjustment
  1582 RSVA - One-time
  1590 Recovery of Regulatory Asset Balances
  1592 Tax Variance - RITC
  1595 Recovery of Regulatory Asset Balances – Sub account 2008.

- In RSL's 2010 IRM Decision (EB-2009-0248), the Board directed RSL to record, in deferral account 1592, the incremental Input Tax Credit ("ITC") it receives on distribution revenue requirement items that were previously subject to PST and become subject to

- HST. RSL has complied with this directive and has been recording these amounts as of July 1, 2010. The application RSL is currently submitting is based on information net of any HST ITCs RSL will receive. As a result, RSL requests approval to discontinue recording these variances as of December 31, 2011.

5.0 DRAFT ISSUES LIST

RSL would expect, based on previous regulatory experience and other hearings, that the following matters pertaining to the 2012 Test Year may constitute issues in this Application:

- The reasonableness of RSL's proposed 2012 capital program; and
- The reasonableness of RSL's proposed 2012 OM&A expenses; and
- The appropriateness of RSL's proposed cost allocation-related adjustments to class
- Specific revenue requirements, reflected in the proposed distribution rates; and
- The appropriateness of RSL's 2012 Load Forecast; and
- The appropriateness of RSL's proposal to recover the Revenue Requirement true-up
- Amount for Smart Meter costs, and to include smart meter assets in rate base
- Accounting Treatment for the conversion to IFRS

Transmission Assets (>50kV)

RSL does not have any transmission assets, or any transmission assets deemed previously by the Board as distribution assets.

Generation Assets

RSL does not have any generation assets, nor is RSL involved in any generation.

6.0 PROCEDURAL ORDERS/MOTIONS/NOTICES

In its decision on EB-2009-0248, the Board directed RSL to file a plan in its 2012 cost of service application to implement a separate rate rider on the delivery component of the bill, for the recovery of future global adjustment sub-account balances from non-RPP customers only.

The Board reaffirmed that direction in its decision on RSL's 2011 IRM (EB-2010-0113).

When RSL made its original submission on EB-2009-0248, RSL did not know if its billing system would be able to break out the global adjustment sub-account and charge the recovery/repayment to non-RPP customers only.

In RSL's response to Board staff IR's for EB-2009-0248, RSL confirmed that its billing (Harris Computers) software was capable of recovering the GA sub account variance from non-RPP customers only.

RSL has been recovering the Global Adjustment variance from non-RPP customers for rates effective May 1, 2010 to date.

There are no other procedural orders, motions, or notices outstanding for RSL.

7.0 ACCOUNTING ORDERS REQUESTED

Rideau St. Lawrence Distribution Inc. does not request any accounting orders at the time of submission.

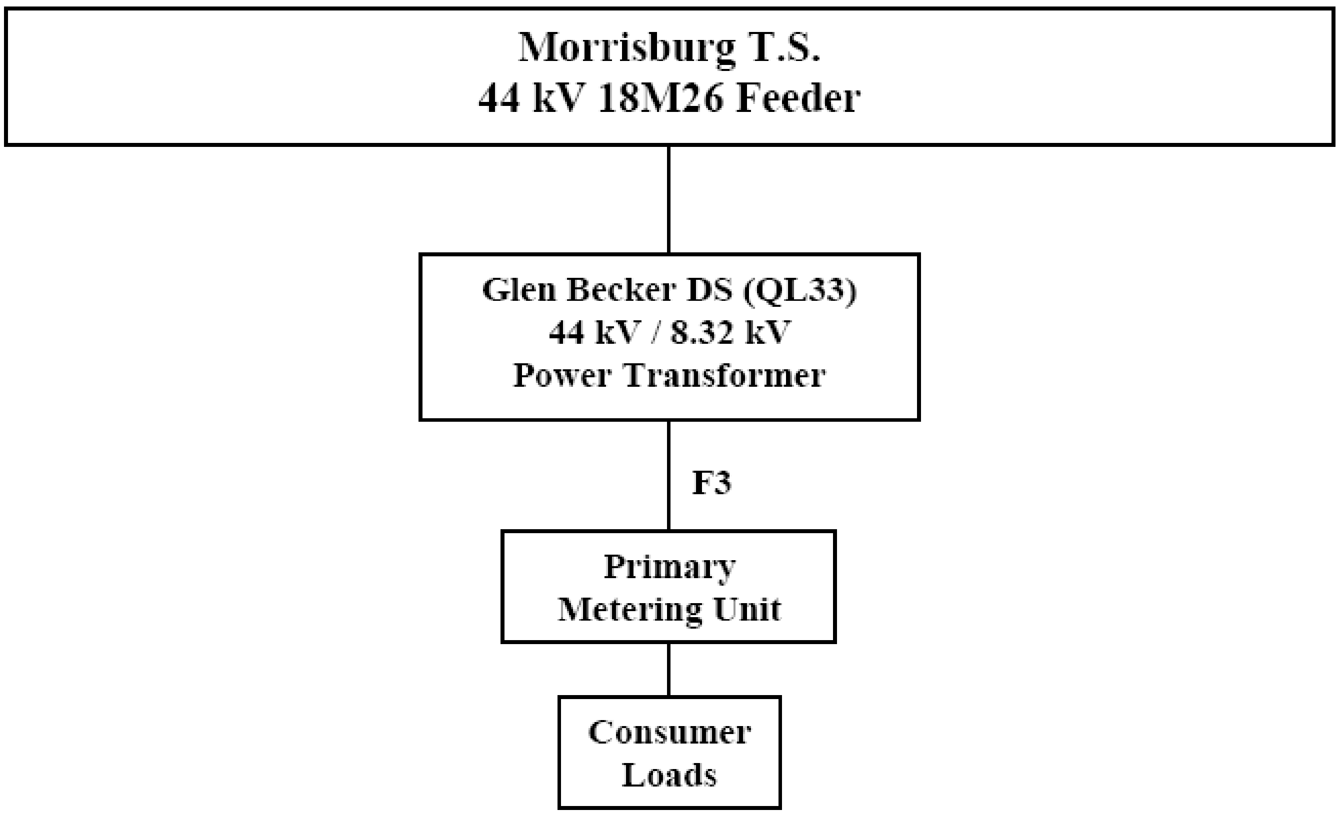
8.0 NON-COMPLIANCE WITH UNIFORM SYSTEM OF ACCOUNTS

Rideau St. Lawrence Distribution Inc. follows the main categories and accounting guidelines as stated in the Uniform System of Accounts.

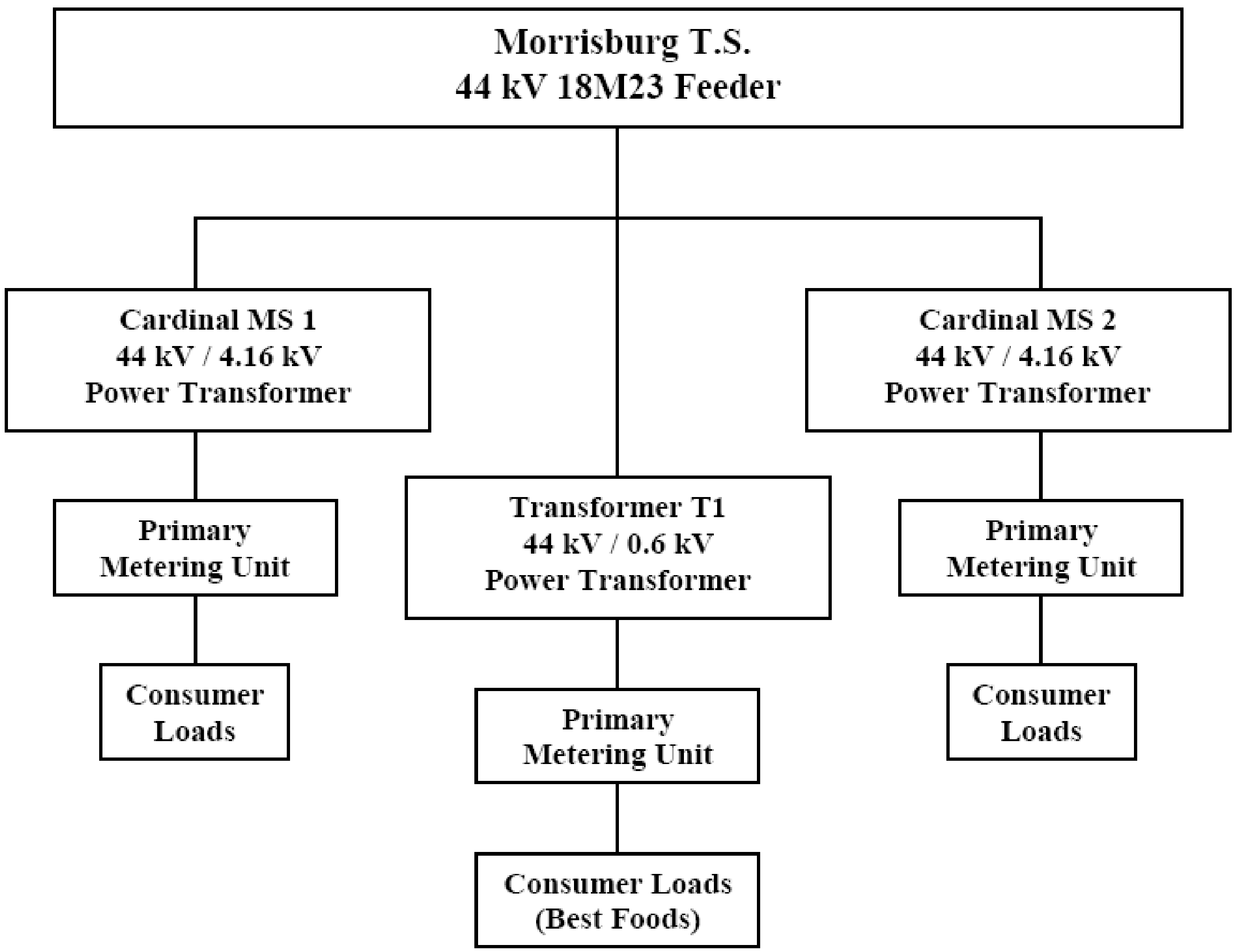
9.0 MAP OF DISTRIBUTION SYSTEM

RIDEAU ST. LAWRENCE DISTRIBUTION INC.

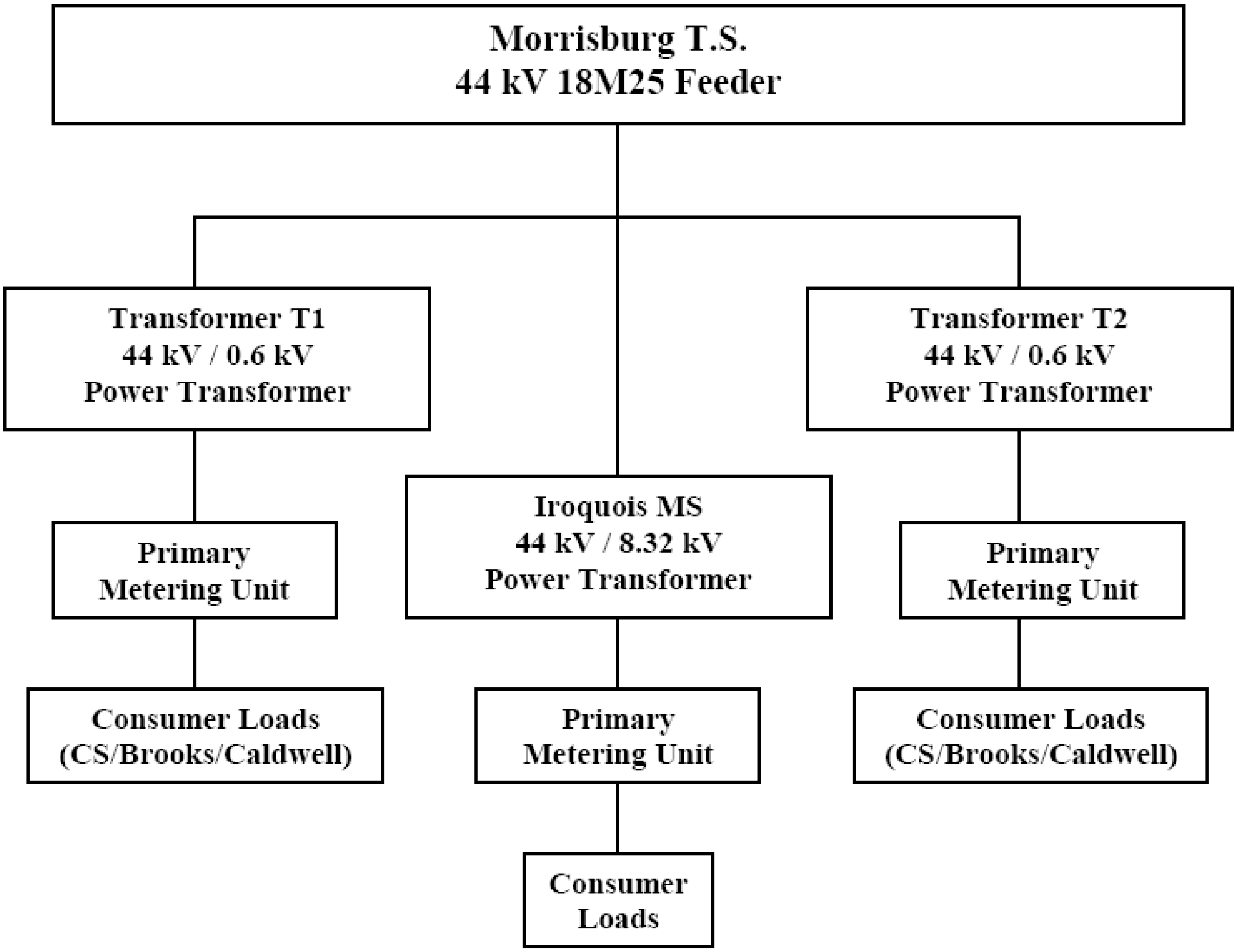
Town of Williamsburg



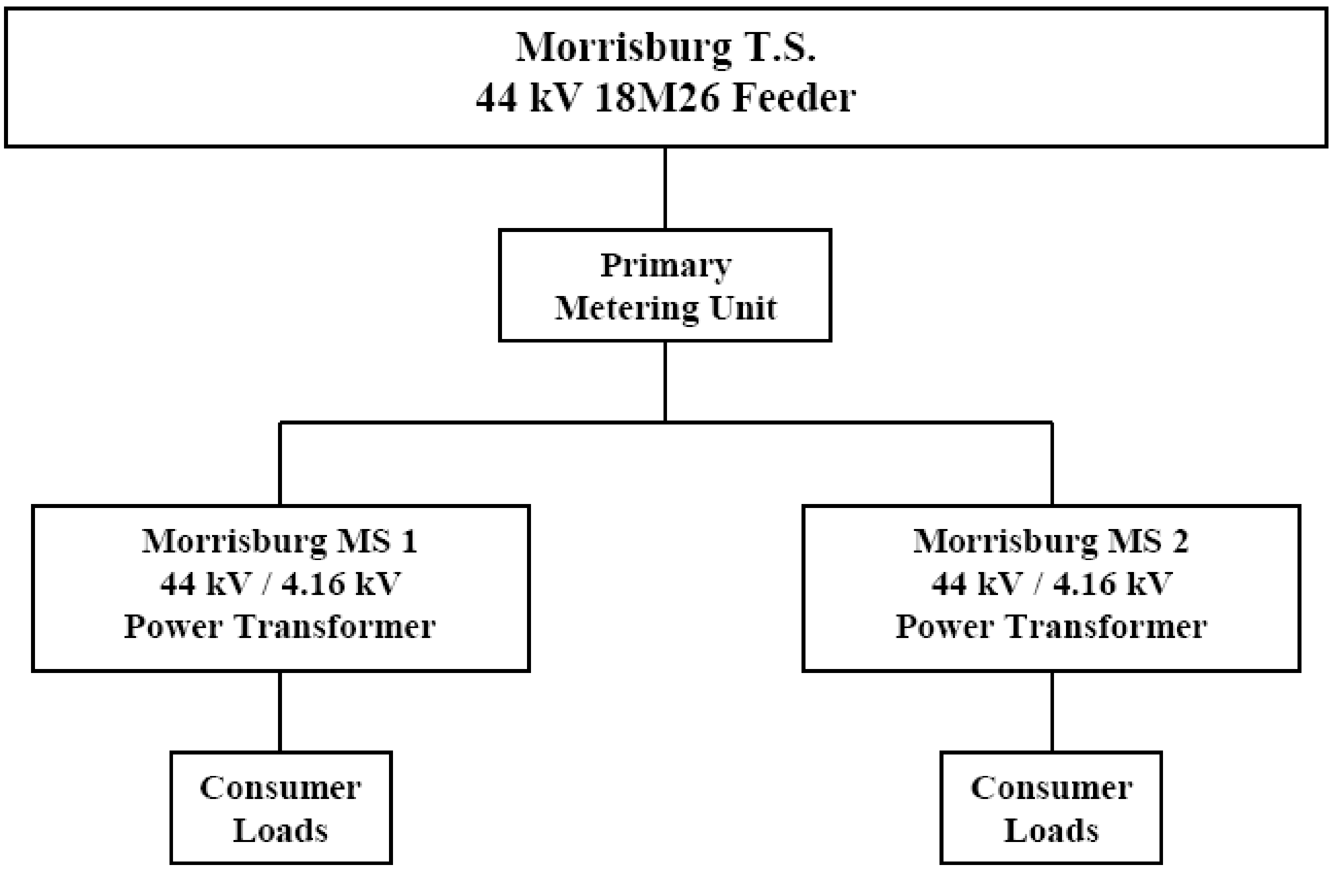
Town of Cardinal



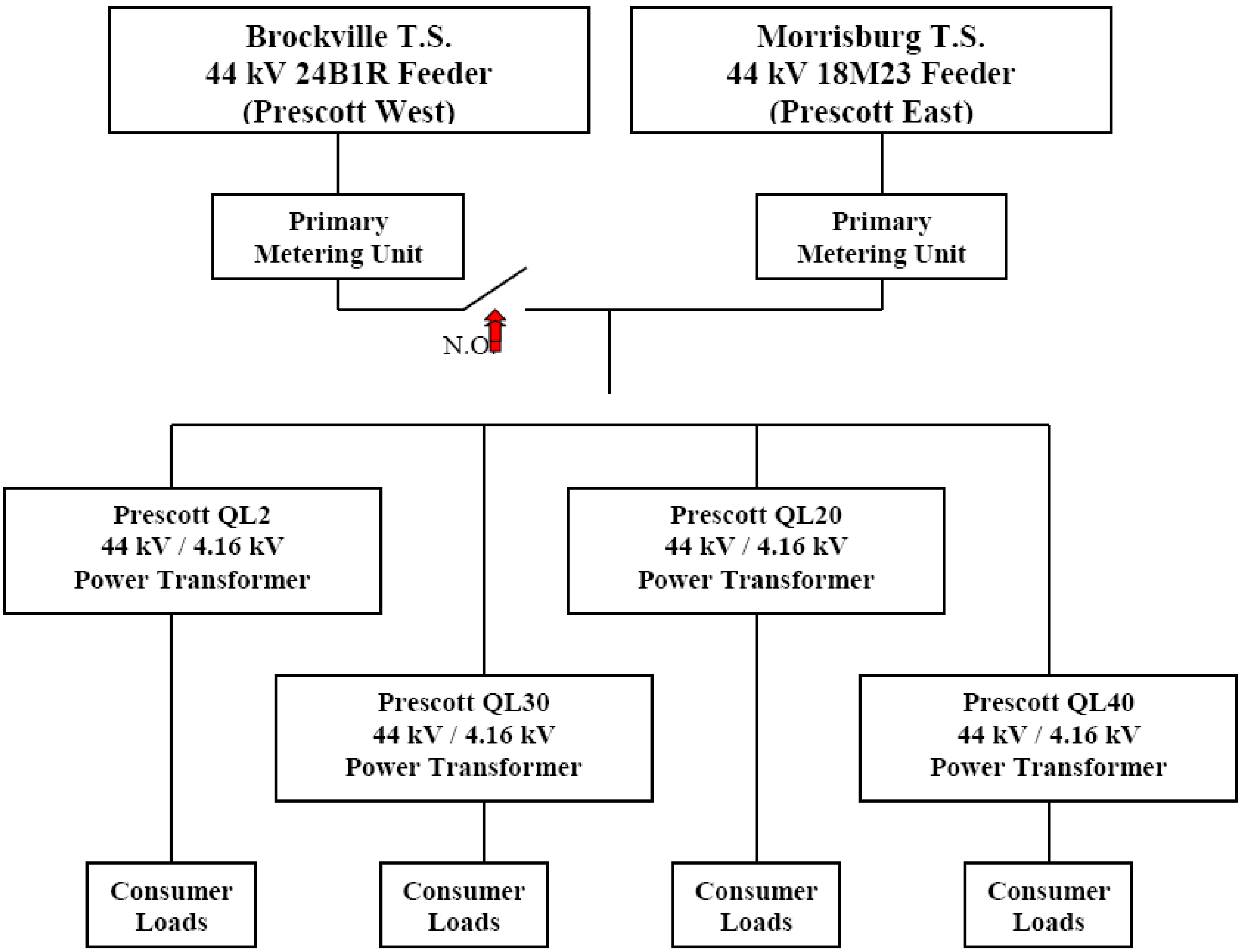
Town of Iroquois



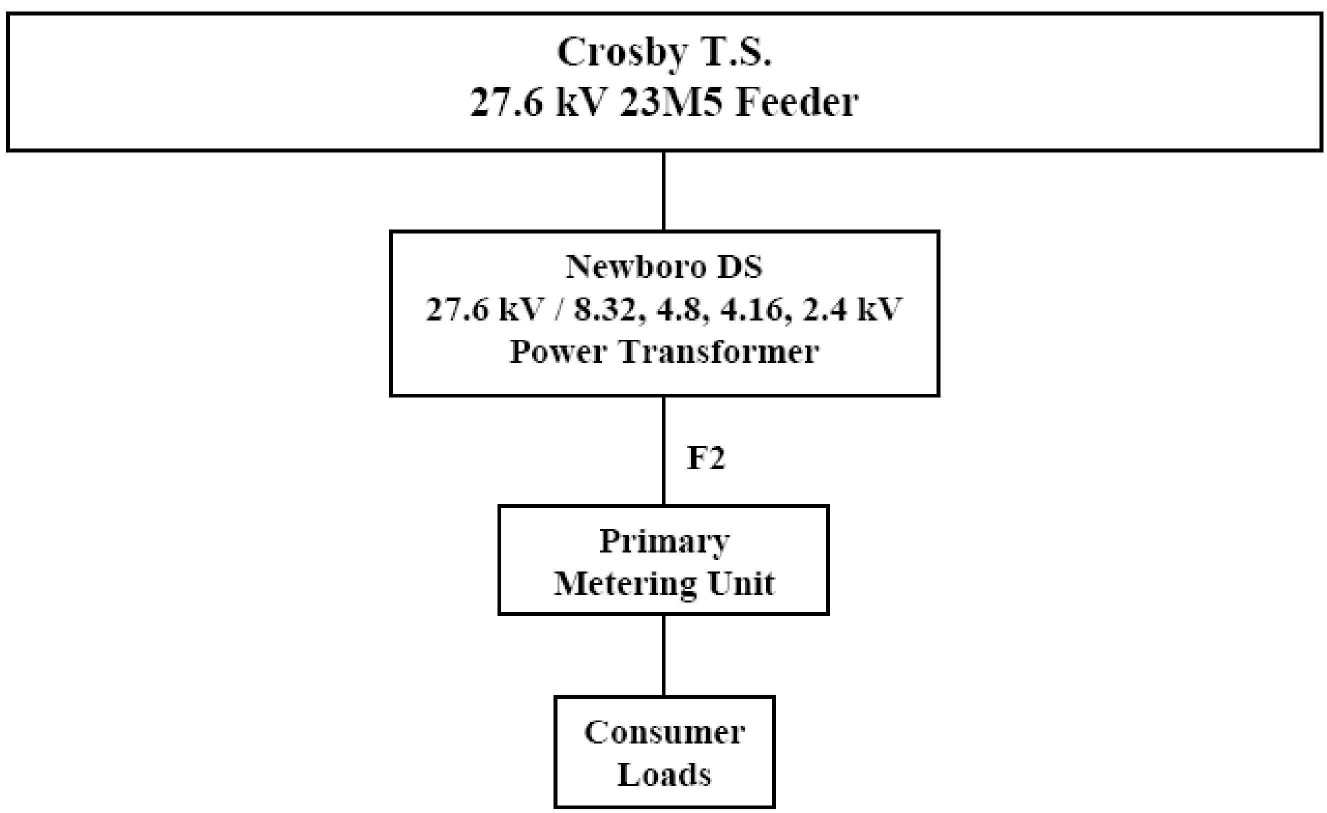
Town of Morrisburg



Town of Prescott



Town of Westport



10.0 LIST OF NEIGHBOURING UTILITIES

UTILITY NAME:	Hydro One Networks	Direct line:	416-345-5000/1-877-955-1155
ADDRESS:	483 Bay Street	Direct Fax:	416-345-5866
	15th Floor Reception	Website:	www.HydroOne.com
	Toronto, Ontario		
	M5G 2P5		

DESCRIPTION OF DISTRIBUTOR

COMMUNITIES SERVED:	The Town of Prescott, and the Villages of Westport, Cardinal, Iroquois, Morrisburg, and Williamsburg.
TOTAL SERVICE AREA:	18 sq km
RURAL SERVICE AREA:	No Rural Service Area
DISTRIBUTION TYPE:	Embedded in Hydro One Networks
Service area population:	11,842
Municipal population:	20,547
Prescott	
BOUNDARIES	Municipal Boundary of the Town of Prescott as it existed March 31, 1999
Cardinal	
BOUNDARIES	Municipal Boundary of the former Village of Cardinal as it existed December 31, 2000, now in the Township of Edwardsburgh/Cardinal
Iroquois	
BOUNDARIES	The Municipal Boundary of the former Village of Iroquois as it existed on March 31, 1995, now in the Township of South Dundas

Morrisburg BOUNDARIES	The municipal boundary of the former Village of Morrisburg as it existed on December 31, 1997, now in the Township of South Dundas
Williamsburg BOUNDARIES	The municipal boundary of the former Village of Williamsburg as it existed on December 31, 1997, now in the Township of South Dundas
Westport BOUNDARIES	The municipal boundary of the Village of Westport as it existed on March 31, 1999

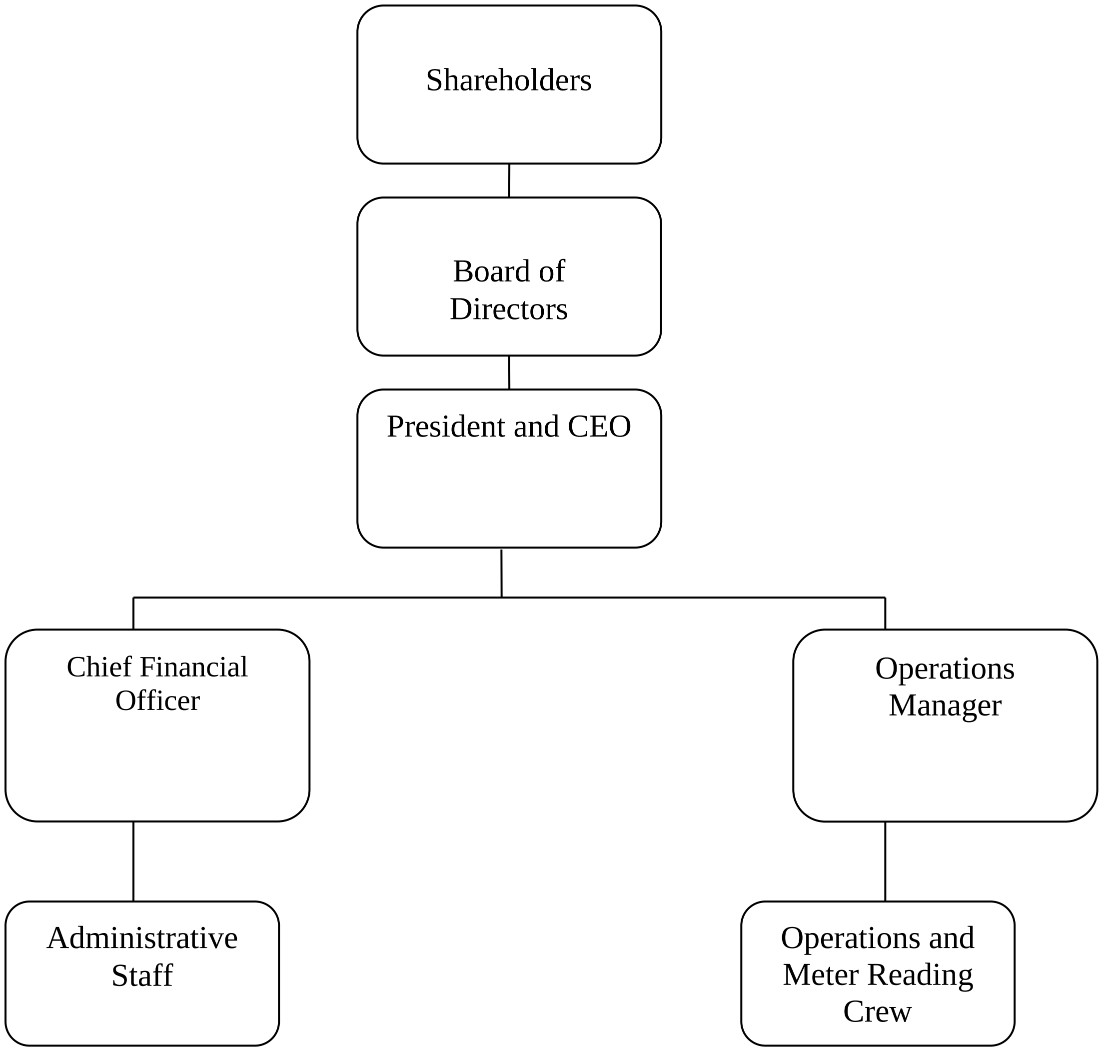
11.0 EXPLANATION OF HOST AND EMBEDDED UTILITIES

Rideau St. Lawrence Distribution Inc. does not host any utilities within its service area.

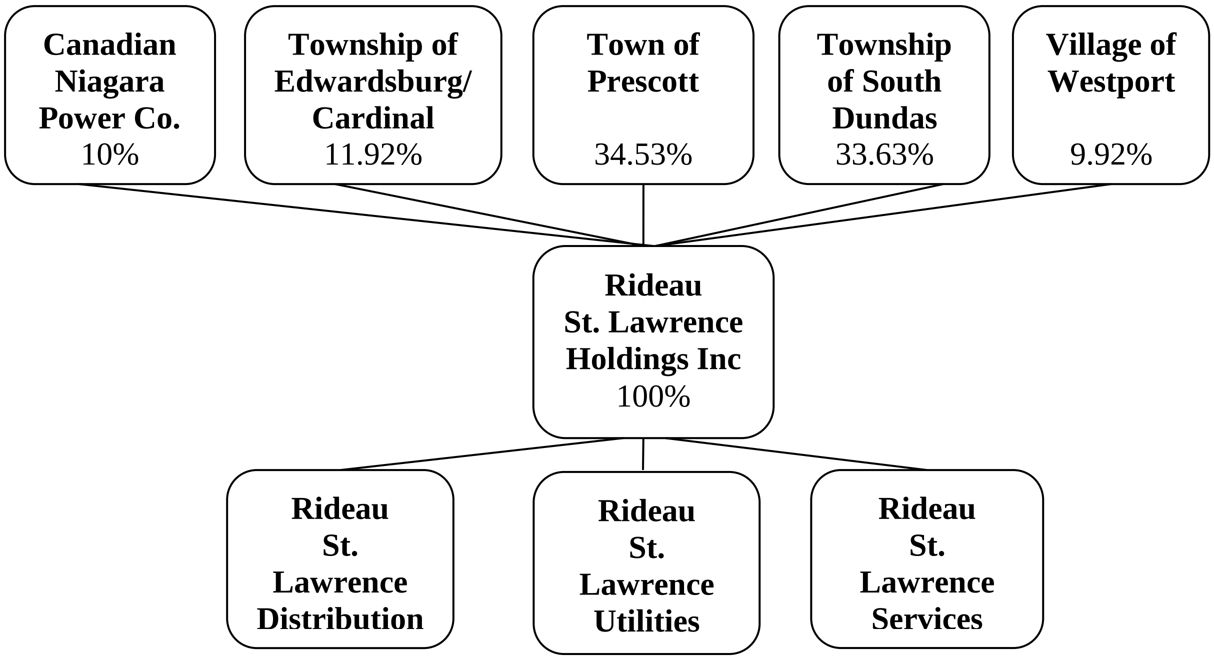
Rideau St. Lawrence Distribution Inc. does not have any embedded utilities within its service area.

Rideau St. Lawrence is embedded within Hydro One.

12.0 UTILITY ORGANIZATIONAL CHART



13.0 CORPORATE ENTITIES RELATIONSHIP CHART



Rideau St. Lawrence Holdings Inc.:

Rideau St. Lawrence Holdings Inc. was incorporated on October 17, 2000 under the laws of the Province of Ontario. The principle activity is as a Holding Company.

Rideau St. Lawrence Distribution:

Rideau St. Lawrence Distribution was incorporated on October 17, 2000 under the laws of the Province of Ontario. The principle activity of the Company is to provide electrical power distribution in the Town of Prescott and the Villages of Westport, Williamsburg, Morrisburg, Iroquois, and Cardinal.

Rideau St. Lawrence Utilities:

Rideau St. Lawrence Utilities was incorporated on October 17, 2000 under the laws of the Province of Ontario. The principle activity of the Company is to provide services to Rideau St. Lawrence Distribution Inc., water and sewer billing to the Town of Prescott and the Villages of Westport, Williamsburg, Morrisburg, Iroquois, and Cardinal, as well as hot water tank rentals and service.

Rideau St. Lawrence Services:

Rideau St. Lawrence Services was incorporated on October 17, 2000 under the laws of the Province of Ontario. The principle activity is to provide dark fibre and high speed communication in Cardinal and Prescott, but is not limited to those locations.

Board of Directors:

Rideau St. Lawrence Holdings	Rideau St. Lawrence Distribution	Ride Utilities au St. Lawrence	Rideau St. Lawrence Services
Mr. D. Gibson	Mr. S. Bryce	Mr. D. Gibson	Mr. D. Gibson
Mr. D. Bradbury	Mr. D. Bradbury	Mr. D. Bradbury	Mr. D. Bradbury
Mr. S. Bryce	Mr. J. Annable	Mr. S. Bryce	Mr. S. Bryce
Mr. H. George		Mr. H. George	Mr. H. George
Mr. J. Allison		Mr. J. Allison	Mr. J. Allison

14.0 PLANNED CHANGES IN CORPORATE AND OPERATIONAL STRUCTURE

Rideau St. Lawrence Distribution Inc. does not have any changes planned for corporate and operational structure at this time.

15.0 STATUS REPORT ON BOARD DIRECTIVES

There are no specific Board directives for RSL.

16.0 CONDITIONS OF SERVICE

RSL is a member of the Cornerstone Hydro Electric Concepts (CHEC) group.

RSL along with the CHEC utilities deemed it necessary to revise its Conditions of Service document. The CHEC working group began the revision process in late 2010 and provided the members with a final draft in July 2011. RSL chose to inform their customers with a note on each bill commencing August 11, 2011.

The note read: "RSL has revised our Conditions of Service document. The document is available at our offices for review. Comments on the revised document will be accepted at the Utility office until Friday Sept. 30, 2011".

The last of the cycle billings were mailed September 6, 2011 – which provided for a minimum three week comment period.

A copy of the proposed Conditions of Service is available in each of our customer service offices.

No comments were received up to September 30th and as of December 1, 2011 – there are still no comments from the public.

A copy of the Revised Conditions of Service was filed with the Board Secretary, November 10, 2011.

A copy of our Conditions of Service is available to the public, at each of our office locations.

17.0 PLANNED CHANGES IN CONDITIONS

There are no changes planned.

18.0 LIST OF WITNESSES

A list of witnesses and their curriculum vitae will be provided as required.

1.0 SUMMARY OF THE APPLICATION

PURPOSE AND NEED

As part of its regulation of electricity distributors, the Ontario Energy Board established a multi-year electricity rate setting plan, which indicated that, commencing with 2008 rates. RSL last filed a Cost of Service Rate Application in 2008, and RSL was included in the Board letter of March 1, 2011, that listed Utilities required to rebase in 2012.

Rideau St. Lawrence Distribution Inc. estimates that its present rates will produce a deficiency in distribution revenue of $570,329 for the 2012 Test Year. Excluded from this estimate is the impact of energy costs. Rideau St. Lawrence Distribution Inc. therefore seeks the Ontario Energy Board's approval to revise its rates applicable to its distribution of electricity for distribution rates effective May 1, 2012 to April 30, 2013 (the "2012 rate year"). The issues to be reviewed in this case, as the applicant sees them, are discussed below.

Through this Application, Rideau St. Lawrence Distribution Inc. seeks:

- Approval to recover the Revenue Deficiency arising from changes in OM&A, Amortization, Rate of Return, Interest and PILS;
- To dispose of Deferral accounts balance listed in Exhibit 9
- To change the Distribution Loss Factor from 1.0774 to 1.0797
- To reflect: - Just and reasonable Distribution Rates that have been modeled in accordance with the OEB Filing Requirements for Distribution Rate Applications.

Rideau St. Lawrence Distribution has been assisted in this rate application by Utility Financial Concepts Inc., and other Consultants, who provided the model used in the determination of the just and reasonable 2012 Distribution Rates. The services of Utility Financial Concepts Inc. were used to provide weather normalized load, and assistance in completing the various Board models. Utility Financial Concepts Inc. used the data provided to RSL by Hydro One Networks Inc. ("HONI") from the Cost Allocation Informational Filing.

The information used in this Application is Rideau St. Lawrence Distribution Inc.'s weather normalized forecasted results for its 2012 Test Year. With the rates presently in effect, Rideau St. Lawrence Distribution Inc. estimates that its revenue for 2012 would not be sufficient to provide a reasonable return. Rideau St. Lawrence Distribution Inc. is also presenting the 2008 Board Approved 2008, historical actual information for fiscal 2008, 2009, and 2010, forecast information for the 2011 Bridge year, and Forecast information for the 2012 Test year.

TIMING

The financial information supporting the Test Year for this Application will be RSL's fiscal year which begins January 1, 2012 and ends December 31, 2012 (the "2012 Test Year"). However, this information will be used to set rates for the period May 1, 2012 to April 30, 2013 (the "Rate Year"). The Test Year revenue requirement is that forecast by the Applicant as needed to enable it to earn a reasonable return for fiscal 2012. For the required revenues to match and appropriately offset the expected costs of service for the Test Year, revised rates reflecting the Board's decision must be effective for volumes consumed on and after May 1, 2012.

CUSTOMER IMPACT

Residential:

A typical residential customer with a monthly consumption of 800 kWh's will see their monthly bill increase by $9.40 or 8.05% of their total bill.

General Service < 50kW:

A typical General Service customer with a monthly consumption of 2000 kWh's will see their monthly bill increase $24.09 or 8.48% of their total bill.

General Service > 50 kW:

A typical General Service customer with a monthly consumption of 166,000 kWh's and a demand of 290 kW, will see their monthly bill increase $426.92 or 2.34% of their total bill.

Street Lighting:

A typical Street Lighting customer with a monthly consumption of 57,000 kWh's, a demand of 140 kW, and 684 connections, will see their monthly bill increase $983.82 or 10.74% of their total bill.

Sentinel Lights:

A typical General Service customer with a monthly consumption of 237 kWh's will see their monthly bill increase $6.03 or 18.17% of their total bill.

Unmetered Scattered Load:

A typical General Service customer with a monthly consumption of 744 kWh's will see their monthly bill increase $13.31 or 11.30% of their total bill.

The following table is used to show the impacts of the rates proposed in this application for a typical customer in each customer class.

Table 1.1

Customer Class bill Impact

Class	Consumption	Current Bill	Proposed Bill	Bill Impact	Bill Impact
		2011 Approved Rates	2012 Proposed Rates	$	%
Residential	800 kWh	$116.87	$125.95	$9.40	8.05%
GS <50kW	2,000 kWh	$283.99	$308.09	$24.09	8.48%
GS >50 kW	290 kW	$18,255.04	$18,681.96	$426.92	2.34%
Street Lighting	140 kW	$9,160.71	$10,144.52	$983.82	10.74%
Sentinel Lights	0.7 kW	$33.16	$39.18	$6.03	18.17%
Scattered Load	744 kWh	$117.73	$131.49	$13.31	11.30%

Return on Equity:

Rideau St. Lawrence Distribution Inc. has assumed a return on equity of 9.42% consistent with the methodology outlined Cost of Capital Parameter Updates for 2012 Cost of Service Applications, as issued November 10, 2011.

Rideau St. Lawrence Distribution Inc. understands the OEB will be finalizing the return on equity for 2012 rates based on January 2012 market interest rate information.

Capital Expenditures:

Rideau St. Lawrence Distribution Inc. continues to reinforce its distribution system in order to meet the demand of new and existing customers in its service territory. This increase in demand comes both from currently unserviced areas as well as existing areas needing upgrades.

Operating and Maintenance Costs:

Operating and maintenance costs have been updated to reflect the impact of inflation and expected changes in costs.

2.0 BUDGET DIRECTIVES

Rideau St. Lawrence Distribution Inc. compiles budget information for the three major components of the budgeting process: revenue forecasts, operating and maintenance expense forecast and capital budgets. This budget information has been compiled for both the bridge and test years, and has been used in this application.

Revenue Forecast:

The energy sales and revenue forecast model was updated to reflect more recent information. This model was then used to prepare the revenues sales and throughput volume and revenue forecast at existing rates for fiscal 2011 and 2012. RSL has adopted a weather normalization methodology using Multifactor Regression (MR) for its load forecast, as outlined in Exhibit 3, and considers such factors as new customer additions and load profiles for all classes of customers.

Operating and Maintenance Expense Forecast:

The operating and maintenance expenses for fiscal 2011 bridge year and the 2012 test year have been forecast using work plans, negotiated wage settlement, Capital budgets, and is strongly influenced by prior year experience.

Capital Budget:

RSL compiles budget information for the three major components of the budgeting process: revenue forecasts, operating and maintenance expense forecast and capital budget forecast.

The Capital Budget is driven by LDC investments in the infrastructure to maintain safety and reliability, by customer requirements, and by regulatory requirements.

This budget information is compiled for both the 2011 Bridge Year and the 2012 Test Year.

3.0 CHANGES IN METHODOLOGY

The following is a summary of the changes in methodology requested by Rideau St. Lawrence Distribution Inc. in the current proceeding:

a) Return on Equity

Rideau St. Lawrence Distribution Inc. has no current request to change the methodology addressing Return on Equity. There is potential for future changes, however, the changes have not been investigated at this time.

b) Interest Rate Applicable to Deferral/Variance Accounts

Rideau St. Lawrence Distribution Inc. has no current request to change the methodology related to the Interest Rate Applicable to Deferral/Variance Accounts.

c) Cost Allocation & Fully Allocated Costing Study

Rideau St. Lawrence Distribution Inc. has no current request to change the methodology addressing Cost Allocation and the Fully Allocated Costing Study. There is the potential for future changes, however, the changes have not been investigated at this time. RSL is proposing to use the results of the Cost Allocation Informational Filing to begin to move towards the Revenue to Cost Ratios as outlined in the Review of Electricity Distribution cost Allocation Policy (EB-2010-0219) issued March 1, 2011. RSL has used the Board-approved Cost Allocation model and methodology and updated the values from the Hydro One Run 3 load forecast using 2011 and 2012 weather normalized forecasted data information.

d) Weather Normalization

RSL has used the regression analysis methodology to determine a prediction model. With regards to the overall process of load forecasting, it is RSL’s view that conducting a regression analysis on historical purchases to produce an equation that will predict energy purchases is appropriate. RSL knows by month the exact number of kWh’s purchased from the IESO for use by customers of RSL. With a regression analysis these purchases can be related to other monthly explanatory variables such as heating degree days and cooling degree days which occur in the same month. The result of the regression analysis produces an equation that predicts the purchases based on the explanatory variables. This prediction model is then used as the basis to forecast the total level of weather normalized purchases for RSL for the bridge and test year, which is converted to Billed kWh by rate class.

RSL’s initial run for the weather normalized projection for 2011 and 2012, with the actual history, and population numbers for RSL service territory, was predicting annual kwh’s under 100 million. RSL believed that these volumes were too low.

RSL’s run used in this rate application, included an adjustment to historical consumption for an Industrial customer that went bankrupt early in 2006. In EB-2007-0762, the Board approved the reduction to annual estimated kwh’s of 1.5 million, from 10 million, for the bankrupt (St. Lawrence Corporation) manufacturing facility that was sold by the trustee, and turned into a warehousing type operation by the new owners. Once the historical load for this Industrial customer was reduced to the last three years average, the regression analysis predicted purchased kWh's of 112,870,798, and billed kWh's of 104,537,301 for 2012. These results produced an R Square was 97%, and RSL deemed them acceptable.

4.0 SCHEDULE OF REVENUE DEFICIENCY – RSL 2012 Test Year

RSL notes there are several factors that contribute to the Revenue Deficiency of $ 570,329 for the Test Year. The list below highlights significant items that contribute to this deficiency.

Labour and Payroll Costs:

Between 2008 and 2011, no incremental additions were made to the staff complement approved as part of our 2008 COS. For 2012 RSL plans to add a Regulatory Analyst, and have included this cost in our account 5655 Regulatory Expenses. All costs for the Rate Application have increased from 2008, resulting in a Test Year Forecast increase of about $100,000.

RSL has also experienced increased benefit costs, and negotiated contract wage increases that were in excess of the increase allowed through the IRM process.

Depreciation:

The addition of $1,294,090 in smart meter assets has added 25% to the Rate base of RSL, and increased depreciation expense of $110,122. The Smart Meters have also increased RSL's Revenue Requirement by almost $265,000.

In 2011, RSL replaced the third and last of its line trucks. All units replaced, had been in service with RSL or its former PUC's for at least 20 years. All units had been fully depreciated, except for the Altec unit added in 2008, for which only a half years depreciation expense was included in 2008 Approved Rates. As a result, depreciation expense for our line trucks has increased by over $50,000 from RSL 2008 COS.

Table 1.2

5.0 Calculation of Revenue Sufficiency/Deficiency

Description	2011 Bridge Actual	2012 Test Existing Rates	2012 Test - Required Revenue
Revenue			
Revenue Deficiency			**570,329**
Distribution Revenue	1,951,876	1,957,800	1,957,800
Other Operating Revenue (Net)	171,953	207,543	207,543
Total Revenue	**2,123,829**	**2,165,343**	**2,735,672**
Costs and Expenses			
Administrative & General, Billing & Collecting	1,094,764	1,170,692	1,170,692
Operation & Maintenance	711,745	721,036	721,036
Depreciation & Amortization	334,223	340,980	340,980
Property Taxes	22,400	23,300	23,300
Capital Taxes	0	0	0
Deemed Interest	208,065	168,423	168,423
Total Costs and Expenses	**2,371,198**	**2,424,431**	**2,424,431**
Less OCT Included Above	0	0	0
Total Costs and Expenses Net of OCT	**2,371,198**	**2,424,431**	**2,424,431**
Utility Income Before Income Taxes	**-247,369**	**-259,088**	**311,241**
Income Taxes:			
Corporate Income Taxes	-46,251	-49,272	39,129
Total Income Taxes	**-46,251**	**-49,272**	**39,129**
Utility Net Income	**-201,118**	**-209,816**	**272,112**
Capital Tax Expense Calculation:			
Total Rate Base	6,998,008	7,221,657	7,221,657
Exemption	15,000,000	15,000,000	15,000,000
Deemed Taxable Capital	**-8,001,992**	**-7,778,343**	**-7,778,343**
Ontario Capital Tax	0	0	0
Income Tax Expense Calculation:			
Accounting Income	-247,369	-259,088	311,241
Tax Adjustments to Accounting Income	-51,023	-58,797	-58,797
Taxable Income	**-298,392**	**-317,885**	**252,443**
Income Tax Expense	-46,251	-49,272	39,129
Tax Rate Refecting Tax Credits	15.50%	15.50%	15.50%
Actual Return on Rate Base:			
Rate Base	6,998,008	7,221,657	7,221,657
Interest Expense	208,065	168,423	168,423
Net Income	-201,118	-209,816	272,112
Total Actual Return on Rate Base	**6,947**	**-41,393**	**440,535**
Actual Return on Rate Base	0.10%	-0.57%	6.10%
Required Return on Rate Base:			
Rate Base	6,998,008	7,221,657	7,221,657
Return Rates:			
Return on Debt (Weighted)	4.96%	3.89%	3.89%
Return on Equity	8.57%	8.57%	8.57%
Deemed Interest Expense	208,065	168,423	168,423
Return On Equity	239,892	272,112	272,112
Total Return	**447,957**	**440,535**	**440,535**
Expected Return on Rate Base	6.40%	6.10%	6.10%
Revenue Deficiency After Tax	**441,010**	**481,928**	**0**
Revenue Deficiency Before Tax	**521,905**	**570,329**	**0**

FINANCE

1.0 FINANCIAL STATEMENTS – 2009 and 2010

RSL's Audited Financial Statements for 2009 and 2010 accompany this Exhibit as Appendix 1B and 1C.

Materiality Thresholds:

Chapter 2 of the Filing Requirements for Transmission and Distribution Applications issued by the Board June 22, 2011 states the relevant default materiality threshold is based on the level of distribution revenue requirement. RSL's proposed service revenue requirement for 2012 is 2,735,672. Chapter 2 of the Filing Requirements for Transmission and Distribution Applications state that "the materiality threshold is $50,000 for distributors with a distribution revenue requirement less than or equal to $10 million".

In an effort to provide a thorough and relevant analysis RSL has used a materiality threshold of $50,000 throughout this Application.

The variance used to determine the OM&A accounts requiring analysis as prescribed by the Filing Requirements (EB-2007-0673 issued September 17, 2008) is 1% of Distribution Expenses, which in RSL's case works out to $22,327.

RSL has provided analysis of all variances greater than $20,000 for OM&A.

2.0 RECONCILIATION BETWEEN FINANCIAL STATEMEMTS AND REGULATORY ACCOUNTING

RSL's advises that there is no variance between the 2010 Audited Financial Statements and the regulatory financial results filed in the Application, therefore a reconciliation is unnecessary.

3.0 PRO FORMA FINANCIAL STATEMEMTS for 2011 AND 2012

Pro Forma Statements for the 2011 Bridge Year and the 2012 Test Year accompany this Exhibit as Appendix 1D and Appendix 1E.

APPENDIX 1A:

Rideau St. Lawrence Distribution Inc.

TARIFF OF RATES AND CHARGES

Proposed Rates - Effective Date May 1, 2012

This schedule supersedes and replaces all previously
approved schedules of Rates, Charges and Loss Factors

EB-2011-0274

RESIDENTIAL SERVICE CLASSIFICATION

This classification applies to an account taking electricity at 750 volts or less where the electricity is used exclusively in a separate metered living accommodation. Customers shall be residing in single-dwelling units that consist of a detached house or one unit of a semi-detached, duplex, triplex or quadruplex house, with a residential zoning.

Separately metered dwellings within a town house complex or apartment building also qualify as residential customers. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order 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 or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy Conservation and Renewable Energy Program, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES – Electricity Component

Rate Rider for Global Adjustment Sub-Account Disposition – effective until April 30, 2013 Applicable only for Non-RPP Customers	$/kWh	(0.0005)

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	13.10
Smart Meter Disposition Rider – effective until April 30, 2013	$	0.85
Stranded Assets Rate Rider – effective until April 30, 2013	$	2.04
Distribution Volumetric Rate	$/kWh	0.0149
Low Voltage Service Rate	$/kWh	0.0017
Rate Rider for Deferral/Variance Account Disposition – effective until April 30, 2013	$/kWh	(0.0006)
Rate Rider for Lost Revenue Adjustment Mechanism (LRAM) Recovery – effective until April 30, 2013	$/kWh	0.0005
Retail Transmission Rate – Network Service Rate	$/kWh	0.0058
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0048

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Appendix 1A
Rideau St. Lawrence Distribution Inc.
TARIFF OF RATES AND CHARGES
Proposed Rates - Effective Date May 1, 2012

This schedule supersedes and replaces all previously
approved schedules of Rates, Charges and Loss Factors

EB-2011-0274

GENERAL SERVICE LESS THAN 50 kW SERVICE CLASSIFICATION

This classification applies to a non-residential account taking electricity at 750 volts or less whose average monthly maximum demand is less than, or is forecast to be less than, 50 kW. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order 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 or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy Conservation and Renewable Energy Program, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES – Electricity Component

Rate Rider for Global Adjustment Sub-Account Disposition – effective until April 30, 2013 Applicable only for Non-RPP Customers	$/kWh	(0.0004)

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	31.43
Smart Meter Disposition Rider – effective until April 30, 2013	$	1.53
Stranded Assets Rate Rider – effective until April 30, 2013	$	6.24
Distribution Volumetric Rate	$/kWh	0.0096
Low Voltage Service Rate	$/kWh	0.0016
Rate Rider for Deferral/Variance Account Disposition– effective until April 30, 2013	$/kWh	(0.0017)
Rate Rider for Lost Revenue Adjustment Mechanism (LRAM) Recovery – effective until April 30, 2013	$/kWh	0.0004
Retail Transmission Rate – Network Service Rate	$/kWh	0.0053
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0044

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Appendix 1A

Rideau St. Lawrence Distribution Inc.

TARIFF OF RATES AND CHARGES

Proposed Rates - Effective Date May 1, 2012

This schedule supersedes and replaces all previously
approved schedules of Rates, Charges and Loss Factors

EB-2011-0274

GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION

This classification applies to a non-residential account whose average monthly maximum demand used for billing purposes is equal to or greater than, or is forecast to be equal to or greater than, 50 kW but less than 5,000 kW.

Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order 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 or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy Conservation and Renewable Energy Program, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES – Electricity Component

Rate Rider for Global Adjustment Sub-Account Disposition – effective until April 30, 2013 Applicable only for Non-RPP Customers	$/kWh	(0.9469)

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	379.29
Smart Meter Funding Adder – effective until April 30, 2013	$	0.0000
Stranded Assets Rate Rider – effective until April 30, 2013	$	0.0000
Distribution Volumetric Rate	$/kW	1.5776
Low Voltage Service Rate	$/kW	0.5762
Rate Rider for Deferral/Variance Account Disposition– effective until April 30, 2013	$/kW	(0.6893)
Rate Rider for Lost Revenue Adjustment Mechanism (LRAM) Recovery – effective until April 30, 2013	$/kW	0.0203
Retail Transmission Rate – Network Service Rate	$/kW	2.2037
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.7658
Retail Transmission Rate – Network Service Rate – Interval Metered	$/kW	2.4621
Retail Transmission Rate – Line and Transformation Connection Service Rate – Interval Metered	$/kW	1.9681

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Appendix 1A

Rideau St. Lawrence Distribution Inc.

TARIFF OF RATES AND CHARGES

Proposed Rates - Effective Date May 1, 2012

This schedule supersedes and replaces all previously
approved schedules of Rates, Charges and Loss Factors

EB-2011-0274

UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION

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 unmetered. Such 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. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order 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 or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy Conservation and Renewable Energy Program, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES – Electricity Component

Rate Rider for Global Adjustment Sub-Account Disposition – effective until April 30, 2013 Applicable only for Non-RPP Customers	$/kWh	0.0000

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge (per customer)	$	9.57
Distribution Volumetric Rate	$/kWh	0.0439
Low Voltage Service Rate	$/kWh	0.0016
Rate Rider for Deferral/Variance Account Disposition – effective until April 30, 2013	$/kWh	(0.0002)
Rate Rider for Lost Revenue Adjustment Mechanism (LRAM) Recovery – effective until April 30, 2013	$/kWh	0.0000
Retail Transmission Rate – Network Service Rate	$/kWh	0.0053
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0044

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Appendix 1A
Rideau St. Lawrence Distribution Inc.
TARIFF OF RATES AND CHARGES
Proposed Rates - Effective Date May 1, 2012

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2011-0274

SENTINEL LIGHTING SERVICE CLASSIFICATION

This classification refers to accounts that are an unmetered lighting load supplied to a sentinel light. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order 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 or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy Conservation and Renewable Energy Program, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES – Electricity Component

Rate Rider for Global Adjustment Sub-Account Disposition – effective until April 30, 2013 Applicable only for Non-RPP Customers	$/kWh	0.0000

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge (per connection)	$	1.60
Stranded Assets Rate Rider – effective until April 30, 2013	$	0.0000
Distribution Volumetric Rate	$/kW	11.7143
Low Voltage Service Rate	$/kW	0.4547
Rate Rider for Deferral/Variance Account Disposition – effective until April 30, 2013	$/kW	0.9301
Retail Transmission Rate – Network Service Rate	$/kW	1.6704
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.3936

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Appendix 1A

Rideau St. Lawrence Distribution Inc.

TARIFF OF RATES AND CHARGES

Proposed Rates - Effective Date May 1, 2012

This schedule supersedes and replaces all previously
approved schedules of Rates, Charges and Loss Factors

EB-2011-0274

STREET LIGHTING SERVICE CLASSIFICATION

This classification applies to an account for roadway lighting with a Municipality, Regional Municipality, Ministry of Transportation and private roadway lighting, controlled by photo cells. The consumption for these customers will be based on the calculated connected load times the required lighting times established in the approved OEB street lighting load shape template. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order 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 or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy Conservation and Renewable Energy Program, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES – Electricity Component

Rate Rider for Global Adjustment Sub-Account Disposition – effective until April 30, 2013 Applicable only for Non-RPP Customers	$/kWh	(1.4035)

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge (per connection)	$	2.96
Distribution Volumetric Rate	$/kW	11.2852
Low Voltage Service Rate	$/kW	0.4455
Rate Rider for Deferral/Variance Account Disposition – effective until April 30, 2013	$/kW	(0.8202)
Retail Transmission Rate – Network Service Rate	$/kW	1.6620
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.3652

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Appendix 1A

Rideau St. Lawrence Distribution Inc.

TARIFF OF RATES AND CHARGES

Proposed Rates - Effective Date May 1, 2012

This schedule supersedes and replaces all previously
approved schedules of Rates, Charges and Loss Factors

EB-2011-0274

microFIT GENERATOR SERVICE CLASSIFICATION

This classification applies to an electricity generation facility contracted under the Ontario Power Authority's microFIT program and connected to the distributor's distribution system. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order 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 or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy Conservation and Renewable Energy Program, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	5.25

ALLOWANCES

Transformer Allowance for Ownership - per kW of billing demand/month	$/kW	(0.60)
Primary Metering Allowance for transformer losses – applied to measured demand and energy	%	(1.00)

Appendix 1A
Rideau St. Lawrence Distribution Inc.
TARIFF OF RATES AND CHARGES
Proposed Rates - Effective Date May 1, 2012

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2011-0274

SPECIFIC SERVICE CHARGES

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No 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 or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy Conservation and Renewable Energy Program, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

Customer Administration		
Arrears certificate	$	15.00
Statement of account	$	15.00
Pulling post-dated cheques	$	15.00
Duplicate invoices for previous billing	$	15.00
Request for other billing information	$	15.00
Easement letter	$	15.00
Income tax letter	$	15.00
Notification charge	$	15.00
Account history	$	15.00
Credit reference/credit check (plus credit agency costs)	$	15.00
Returned cheque charge (plus bank charges)	$	15.00
Charge to certify cheque	$	15.00
Legal letter Charge	$	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	30.00
Meter dispute charge plus Measurement Canada fees (if meter found correct)	$	30.00
Special meter reads	$	30.00
Non-Payment of Account		
Late Payment - per month	%	1.50
Late Payment - per annum	%	19.56
Collection of account charge – no disconnection	$	30.00
Collection of account charge – no disconnection – after regular hours	$	165.00
Disconnect/Reconnect at meter - during regular hours	$	65.00
Disconnect/Reconnect at meter - after regular hours	$	185.00
Disconnect/Reconnect at pole - during regular hours	$	185.00
Disconnect/Reconnect at pole - after regular hours	$	415.00
Service call – customer owned equipment	$	30.00
Service call – after regular hours	$	165.00
Install/Remove load control device – during regular hours	$	65.00
Install/Remove load control device – after regular hours	$	185.00
Temporary service install and remove – overhead – no transformer	$	500.00
Temporary service install and remove – underground – no transformer	$	300.00
Temporary service install and remove – overhead – with transformer	$	1,000.00
Specific Charge for Access to the Power Poles – per pole/year	$	22.35

Appendix 1A

Rideau St. Lawrence Distribution Inc.

TARIFF OF RATES AND CHARGES

Proposed Rates - Effective Date May 1, 2012

This schedule supersedes and replaces all previously
approved schedules of Rates, Charges and Loss Factors

EB-2011-0274

RETAIL SERVICE CHARGES (if applicable)

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order 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 or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy Conservation and Renewable Energy Program, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

Retail Service Charges refer to services provided by a distributor to retailers or customers related to the supply of competitive electricity

One-time charge, per retailer, to establish the service agreement between the distributor and the retailer	$	100.00
Monthly Fixed Charge, per retailer	$	20.00
Monthly Variable Charge, per customer, per retailer	$/cust.	0.50
Distributor-consolidated billing charge, per customer, per retailer	$/cust.	0.30
Retailer-consolidated billing credit, per customer, per retailer	$/cust.	(0.30)
Service Transaction Requests (STR)		
Request fee, per request, applied to the requesting party	$	0.25
Processing fee, per request, applied to the requesting party	$	0.50
Request for customer information as outlined in Section 10.6.3 and Chapter 11 of the Retail Settlement Code directly to retailers and customers, if not delivered electronically through the Electronic Business Transaction (EBT) system, applied to the requesting party		
Up to twice a year no charge		
More than twice a year, per request (plus incremental delivery costs)	$	2.00

LOSS FACTORS

If the distributor is not capable of prorating changed loss factors jointly with distribution rates, the revised loss factors will be implemented upon the first subsequent billing for each billing cycle.

Total Loss Factor – Secondary Metered Customer < 5,000 kW	1.0797
Total Loss Factor – Secondary Metered Customer > 5,000 kW	N/A
Total Loss Factor – Primary Metered Customer < 5,000 kW	1.0689
Total Loss Factor – Primary Metered Customer > 5,000 kW	N/A

APPENDIX 1B

RIDEAU ST. LAWRENCE DISTRIBUTION INC.

FINANCIAL STATEMENTS

December 31, 2009

Craig Keen Despatie Markell LLP

RIDEAU ST. LAWRENCE DISTRIBUTION INC.

December 31, 2009

CONTENTS

AUDITORS' REPORT

To the Shareholder of
Rideau St. Lawrence Distribution Inc.

We have audited the balance sheet of Rideau St. Lawrence Distribution Inc. as at December 31, 2009 and the statements of operations and 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 Rideau St. Lawrence Distribution Inc. as at December 31, 2009 and the results of its operations and retained earnings and its cash flows for the year then ended in accordance with Canadian generally accepted accounting principles.

Craig Keen Despatie Markell LLP

Cornwall, Ontario
April 28, 2010

CHARTERED ACCOUNTANTS
Licensed Public Accountants

RIDEAU ST. LAWRENCE DISTRIBUTION INC.

BALANCE SHEET

As at December 31, 2009

	2009	2008
ASSETS		
CURRENT		
Cash	**$ 511,914**	$ 663,168
Investments (Note 2)	**8,447**	6,033
Accounts receivable	**1,053,336**	933,481
Unbilled revenue	**1,111,371**	1,178,176
Inventory	**200,906**	186,545
Payments-in-lieu of corporate taxation	**-**	5,847
Prepaid expenses	**42,844**	61,975
	2,928,818	3,035,225
CAPITAL (Note 3)	**4,115,106**	3,855,541
NET REGULATORY ASSETS (Note 4)	**1,165,899**	313,740
	$ 8,209,823	$ 7,204,506
LIABILITIES		
CURRENT		
Temporary advances (Note 5)	**$ 1,078,403**	-
Accounts payable	**1,500,406**	1,633,626
Customer deposits	**79,000**	79,000
Payments-in-lieu of corporate taxation	**306**	-
Regulatory liabilities (Note 6)	**14,508**	19,314
Advances from related parties (Note 7)	**311,512**	232,819
Current portion of long-term debt	**117,500**	109,500
	3,101,635	2,074,259
CUSTOMER DEPOSITS	**51,127**	70,992
LONG-TERM DEBT (Note 8)	**1,234,322**	1,354,154
ADVANCES FROM RELATED PARTY (Note 9)	**343,031**	343,031
	4,730,115	3,842,436
SHAREHOLDER'S EQUITY		
CAPITAL STOCK (Note 10)	**2,511,123**	2,511,123
RETAINED EARNINGS	**968,585**	850,947
	3,479,708	3,362,070
	$ 8,209,823	$ 7,204,506

APPROVED ON BEHALF OF THE BOARD:

____________________ Director

____________________ Director

____________________ Date

See Accompanying Notes

RIDEAU ST. LAWRENCE DISTRIBUTION INC.

STATEMENT OF OPERATIONS AND RETAINED EARNINGS

For the year ended December 31, 2009

	2009	2008
REVENUE	$ **10,962,543**	$ 10,525,126
COST OF ENERGY	**8,978,754**	8,771,341
GROSS MARGIN	**1,983,789**	1,753,785
OTHER INCOME		
Late payment and other charges	**155,394**	167,178
Rentals	**37,235**	47,024
Investment income	**4,989**	26,583
Interest improvement charges	**25,118**	20,123
Gain on disposal of capital assets	**-**	4,100
Special programs	**5,039**	-
	227,775	265,008
TOTAL REVENUE NET OF COST OF ENERGY	**2,211,564**	2,018,793
EXPENSES		
Administration	**676,115**	651,530
Amortization	**277,765**	228,996
Billing and collecting	**439,070**	395,900
Interest on long-term debt	**80,116**	89,794
Operation maintenance	**525,366**	458,045
	1,998,432	1,824,265
INCOME BEFORE OTHER ITEMS	**213,132**	194,528
CONSERVATION AND DEMAND MANAGEMENT PROGRAM (Note 6)	**50,798**	-
RECOVERY OF PRE-MARKET OPENING COST OF POWER	**-**	40,870
GAIN ON EXCHANGE OF INVESTMENTS (Note 2)	**2,414**	2,413
INCOME BEFORE PAYMENTS-IN-LIEU OF CORPORATE TAXATION	**266,344**	237,811
PAYMENTS-IN-LIEU OF CORPORATE TAXATION (Note 11)	**28,706**	23,799
NET INCOME FOR THE YEAR	**237,638**	214,012
RETAINED EARNINGS, beginning of year	**850,947**	743,255
	1,088,585	957,267
DIVIDENDS	**120,000**	106,320
RETAINED EARNINGS, end of year	$ **968,585**	$ 850,947

See Accompanying Notes

RIDEAU ST. LAWRENCE DISTRIBUTION INC.

STATEMENT OF CASH FLOWS

For the year ended December 31, 2009

		2009		2008
CASH FROM OPERATING ACTIVITIES				
Net income for the year	$	**237,638**	$	214,012
Items not requiring an outlay of funds				
Amortization		**277,765**		228,996
Gain on sale of capital assets		**-**		(4,100)
Gain on exchange of investments		**(2,414)**		(2,413)
Net changes in non-cash working capital balances				
Accounts receivable		**(119,855)**		(101,607)
Unbilled revenue		**66,805**		(36,936)
Inventory		**(14,360)**		5,445
Payments-in-lieu of corporate taxation		**6,153**		(19,738)
Prepaid expenses		**19,131**		(12,746)
Accounts payable		**(133,220)**		205,104
Deferred revenue		**-**		(40,795)
Regulatory liabilities		**(4,806)**		(135,657)
Advances from related parties		**78,693**		(212,951)
		411,530		86,614
CASH USED IN INVESTING ACTIVITIES				
Net additions to capital assets		**(537,330)**		(532,550)
(Increase) decrease in net regulatory assets		**(852,160)**		320,342
Proceeds on disposition of capital assets		**-**		4,100
		(1,389,490)		(208,108)
CASH USED IN FINANCING ACTIVITIES				
Decrease in long-term debt		**(111,832)**		(106,389)
Increase in customer deposits		**(19,865)**		-
Decrease in long-term regulatory liabilities		**-**		(19,314)
Dividends paid		**(120,000)**		(106,320)
		(251,697)		(232,023)
DECREASE IN CASH AND EQUIVALENT		**(1,229,657)**		(353,517)
CASH AND EQUIVALENT, beginning of year		**663,168**		1,016,685
CASH AND EQUIVALENT, end of year	$	**(566,489)**	$	663,168
REPRESENTED BY:				
Cash	$	**511,914**	$	663,168
Temporary advances		**(1,078,403)**		-
	$	**(566,489)**	$	663,168
Supplementary information:				
Interest paid	$	**80,116**	$	89,794

See Accompanying Notes

Payments-in-lieu of corporate taxation	**$ 22,553**	$ 43,537

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

The corporation follows Canadian generally accepted accounting principles for electrical utilities prescribed in the Ontario Energy Board's Accounting Procedures Handbook under the authority of Acts of the Province of Ontario and permitted by the Ontario Energy Board.

(a) Revenue recognition

Revenue from the sale of electricity is recorded when billed. Unbilled revenue is the accrual for electricity sold between the last billing date and the year-end date. The unbilled revenue adjustment is the change between the opening and closing balances of unbilled revenue and is included in revenue. Other income is recorded when services have been provided.

(b) Investments

Investments are recorded at lower of cost and market.

(c) Inventory

Inventory is valued at the lower of cost and net realizable value. Inventory is recorded using the average cost method.

(d) Capital assets and amortization

Capital assets are stated at acquisition cost and amortized using the straight-line method over five to forty years.

(e) Construction in progress

Capital items purchased for capital projects under construction are included in construction in progress and are not amortized until put into service.

(f) Contributions and grants in aid of construction

Contributions and grants received in aid of construction are recorded as a deduction against capital assets. The amount is amortized on the same basis as the asset constructed and credited to amortization expense. No amortization is recorded until the asset is in use.

(g) Customer deposits

Deposits taken to guarantee the payment of power bills or contract performance are shown as a current or long-term liability depending on the terms of repayment.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

(h) Use of estimates

The preparation of financial statements in conformity with Canadian generally accepted accounting principles 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 revenues and expenditures during the period. Actual results could differ from these estimates.

(i) Net regulatory assets

(i) Retail settlement variance accounts

Retail settlement variance accounts are the net of sales and expenses incurred by the corporation for retail settlement after the commencement of market opening on May 1, 2002. The net sales and expenses are to be recovered through future rate increases, under Article 490 of the Ontario Energy Board Accounting Procedures Handbook. A return of capital is capitalized on these amounts based on Article 490.

(ii) Smart meter capital cost variance account

Smart meter capital cost variance account is the net of smart meter capital expenses and related incremental operating, maintenance, amortization and administration expenses incurred by the corporation less accumulated billings to offset those costs. The net expenses are to be recovered through future rate increases under Article 490 of the Ontario Energy Board Accounting Procedures Handbook. A return of capital is capitalized on these amounts based on Article 490.

In the absence of such regulations, these costs would have been expensed or included in capital assets when incurred, and no rate of return of capital would be capitalized under Canadian generally accepted accounting principles.

(j) Corporate income and capital taxes

Under the Electricity Act, 1998, the corporation is required to make payments-in-lieu of corporate taxes to the Ontario Energy Finance corporation. These payments are calculated in accordance with the rules of computing income and taxable capital and other relevant amounts contained in the Income Tax Act (Canada) and the Corporation Tax Act (Ontario) as modified by the Electricity Act, 1998, and related regulations.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

(j) Corporate income and capital taxes (continued)

The corporation provides for payments-in-lieu of corporate income taxes relating to its regulated businesses using the taxes payable method as directed by the Ontario Energy Board. 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. When recorded future income taxes become payable, it is expected that they will be included in the rates approved by the Ontario Energy Board and recovered from the customers of the corporation at that time.

(k) Financial instruments

(i) Fair value of financial instruments

CICA Handbook Section 3855 establishes standards for recognizing and measuring financial assets, financial liabilities and derivatives. This standard prescribes when to recognize a financial instrument in the balance sheet and at what amount. Depending on the classification, fair value or cost based measures are used. The standard also prescribes the basis of presentation for gains and losses on financial instruments. Based on financial instrument classification, gains and losses on financial instruments are recognized in net income or as other comprehensive income.

The corporation has made the following classifications:

(i) Cash and investments are classified as "held for trading." They are measured at fair value and any gains or losses resulting from the re-measurement at end of each period are recognized in net income.

(ii) Accounts receivable and unbilled revenue are classified as "loans and receivables." They are recorded at cost, which upon their initial measurement is equal to their fair value. Subsequent measurements are recorded at amortized cost using the effective interest method.

(iii) Accounts payables and customer deposits are classified as "financial liabilities." They are recorded at their cost which upon their initial measurement is equal to their fair value. Subsequent measurements are recorded at amortized cost using the effective interest method.

The carrying amounts reported on the balance sheet for cash, investments, accounts receivable, unbilled revenue, accounts payable and customer deposits, approximate fair values due to the immediate and short-term maturities of these financial instruments.

The fair value of long-term debt, including the current portion, is based on rates currently available to the corporation with similar terms and maturities and approximates its carrying amounts as disclosed on the balance sheet.

(ii) Concentration of credit risk

The corporation does not believe it is subject to any significant concentration of credit risk. Cash is in place with major financial institutions. Accounts receivable are the result of sales to individuals, corporations and not-for-profit organizations geographically concentrated within Eastern Ontario.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

(k) Financial instruments (continued)

(iii) Comprehensive income - Section 1530

This Section describes the recognition and disclosure requirements with respect to comprehensive income. Comprehensive income consists of net income and other comprehensive income. Other comprehensive income represents the changes in the fair value of financial instruments which have not been included in net income. As the corporation did not have any adjustments to other comprehensive income during the year, this standard does not have an impact on the financial statements.

(l) International Financial Reporting Standards ("IFRS")

The Canadian Institute of Chartered Accountants announced that Canadian publicly accountable enterprises will be required to adopt International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("ISAB"), effective January 1, 2011. The corporation is considered a publicly accountable enterprise and will be required to adopt IFRS effective January 1, 2011 for its financial statements. While the corporation is currently developing an implementation plan for the adoption of IFRS, the financial reporting impact of the transition to IFRS cannot be reasonably estimated at this time.

2. INVESTMENTS

The corporation exchanged its ownership of 18,000 units with a zero carrying value of Enerconnect Limited Partnership for 12,067 shares of Utilismart Corporation in December 2007. The shares of Utilismart Corporation are to be distributed to the corporation over a three year period. The corporation received 2,414 shares during the year for an accounting gain of $2,414 (2008 - $2,413).

3. CAPITAL

	Cost	**Accumulated Amortization**	**Net 2009**	Net 2008
Land	**$ 84,205**	**$ -**	**$ 84,205**	$ 84,205
Buildings, leasehold improvements and fixtures	**91,084**	**6,322**	**84,762**	80,654
Distribution equipment	**5,544,594**	**1,447,481**	**4,097,113**	3,850,941
Tools and equipment	**129,209**	**84,488**	**44,721**	50,670
Computer hardware and software	**270,985**	**171,244**	**99,741**	92,103
Construction in progress	**-**	**-**	**-**	7,064
Less: Contributions in aid of construction	**(360,987)**	**(65,551)**	**(295,436)**	(310,096)
	$ 5,759,090	**$ 1,643,984**	**$ 4,115,106**	$ 3,855,541

4. NET REGULATORY ASSETS

		2009		2008
Retail settlement variance accounts	**$**	**346,371**	$	316,349
Smart meter capital cost variance account		**819,528**		(2,609)
	$	**1,165,899**	$	313,740

The Ontario Energy Board approved final billing rates subsequent to year-end for the recovery of retail settlement variance Group One accounts of $235,000 in 2010. The Ontario Energy Board also approved billing rates for the recovery of smart meter capital costs on a non-prudential basis from $1 to $2 per customer per month.

5. TEMPORARY ADVANCES

		2009		2008
Demand loan	**$**	**833,403**	$	-
Demand loan		**245,000**		-
	$	**1,078,403**	$	-

Demand loans are non-revolving loans that bear interest at prime, interest only payments for first twelve months, maximum borrowing limit of $1,695,000 and are secured by a general security agreement dated May 20, 2009. The corporation has an overdraft lending facility up to $750,000 that was not utilized as of December 31, 2009 with the same terms and conditions as the demand loans indicated above. Rideau St. Lawrence Holdings Inc. provided a guarantee for indebtedness of the corporation up to $2,445,000 dated July 9, 2009. Management's intention is to refinance the temporary advances with long-term fixed rate term loans in 2010 with principal repayment terms amortized over a maximum period of ten years.

6. REGULATORY LIABILITIES

Regulatory liabilities represents funds received for the transfer of Hydro One low voltage regulatory assets and the Conservation and Demand Management (C&DM) program. Costs are recorded against these funds when incurred. Transactions are summarized as follows:

	Hydro One Low Voltage Transfer	C&DM Program	2009	2008
Balance, beginning of year	**$ 19,314**	**$ -**	**$ 19,314**	$ 174,285
Transfer of regulatory liabilities	**38,718**	**-**	**38,718**	-
Disbursements against regulatory liabilities	**(43,524)**	**-**	**(43,524)**	(154,971)
Balance, end of year	**$ 14,508**	**$ -**	**$ 14,508**	$ 19,314

The Conservation and Demand Management (C&DM) program was completed in 2008 of which $50,798 was allocated to capital asset additions. The revenue allocated to the capital asset additions is recorded as income in 2009.

7. ADVANCES FROM RELATED PARTIES

	2009	2008
Advances from Rideau St. Lawrence Utilities Inc.	**$ 302,030**	$ 228,257
Advances from Rideau St. Lawrence Services Inc.	**9,482**	4,562
	$ 311,512	$ 232,819

The corporation is related to Rideau St. Lawrence Holdings Inc., Rideau St. Lawrence Utilities Inc., and Rideau St. Lawrence Services Inc. through common ownership. The corporation is a wholly-owned subsidiary of Rideau St. Lawrence Holdings Inc.

During the year, the corporation incurred administration, maintenance and other service expenditures with Rideau St. Lawrence Utilities Inc. Terms and conditions of transactions with Rideau St. Lawrence Utilities Inc. are covered by a Master Services Agreement dated November 1, 2000. Under this agreement, Rideau St. Lawrence Utilities Inc. provides specified services to the corporation on a fee for services basis.

8. LONG-TERM DEBT

		2009		2008
Loan payable, interest at 4.99%, payable in blended monthly payments of $10,096, due July 2011, secured by specific assets	**$**	**188,470**	$	300,302
Promissory note, Corporation of the Township of Edwardsburgh/Cardinal		**225,000**		225,000
Promissory note, Corporation of the Township of South Dundas		**938,352**		938,352
		1,351,822		1,463,654
Less: current portion		**117,500**		109,500
	$	**1,234,322**	$	1,354,154

The promissory notes bear interest at a rate determined by the Board of Directors not to exceed 7.25% per annum and are unsecured. Principal and interest shall be payable at the discretion of the Board of Directors. Interest rate at December 31, 2009 is 4.99%. The repayment of long-term debt is as follows:

2010	$	117,500
2011		70,970
Thereafter		1,163,352
	$	1,351,822

9. ADVANCES FROM RELATED PARTY

Advances from related party are from Rideau St. Lawrence Holdings Inc., which bears no interest, has no specific terms of repayment, and are unsecured.

10. CAPITAL STOCK

Authorized -

Unlimited common shares

		2009		2008
Issued -				
2,511,123 common shares	**$**	**2,511,123**	$	2,511,123

11. PAYMENTS-IN-LIEU OF CORPORATE TAXATION

The provision for payments-in-lieu of corporate income taxes (PIL's) differs from the amount that would have been recorded using the combined Canadian Federal and Ontario statutory income tax rate. A reconciliation between the statutory and effective tax rates is provided as follows:

		2009		2008
Income before PIL's	$	266,344	$	237,811
Federal and Ontario statutory income tax rates		16.50%		16.50%
PIL's at statutory rate		43,947		39,239
Decrease resulting from:				
Temporary differences:				
Capital cost allowance in excess of amortization		(16,501)		(11,448)
Accounting gain on disposal of capital assets		-		(677)
Accounting gain on exchange of investments		(398)		(398)
Net temporary differences		(16,899)		(12,523)
Permanent differences:				
Corporate Minimum Tax (recovery)		6,266		(88)
Apprenticeship Training Tax Credits		(4,608)		(2,829)
Net permanent differences		1,658		(2,917)
Provision for PIL's	$	28,706	$	23,799
Effective income tax rate		10.78%		10.01%

As at December 31, 2009, future income tax assets of $198,000 (2008 - $215,000), based on current income tax rates, have not been recorded.

12. CONTINGENCIES

The corporation entered into an irrevocable standing letter of credit with a financial institution. The letter of credit is a prudential support obligation required by all small distribution companies in Ontario for the Independent Electricity System Operator (IESO). The prudential support obligation is calculated at $521,467, which the corporation has not exercised as of December 31, 2009.

A class action lawsuit was filed against the corporation and other local electric distribution companies in Ontario by customers who were charged late payment penalties. No settlement have been reached as of April 28, 2010. In management's opinion, the potential settlement is not significant.

APPENDIX 1C

RIDEAU ST. LAWRENCE DISTRIBUTION INC.

FINANCIAL STATEMENTS

December 31, 2010

Craig Keen Despatie Markell LLP

RIDEAU ST. LAWRENCE DISTRIBUTION INC.

December 31, 2010

CONTENTS

INDEPENDENT AUDITORS' REPORT

To the Shareholders of
Rideau St. Lawrence Distribution Inc.

We have audited the accompanying financial statements of Rideau St. Lawrence Distribution Inc., which comprise the balance sheet as at December 31, 2010, and the statement of operations and retained earnings and cash flows for the year then ended, and a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Financial Statements

Management is responsible for the preparation and fair presentation of these financial statements in accordance with Canadian generally accepted accounting principles and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibility

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 comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditors' judgement, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditors considers internal control relevant to the entity's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by administration, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the financial statements present fairly, in all material respects, the balance sheet of Rideau St. Lawrence Distribution Inc. as at December 31, 2010, and its statement of income and retained earnings and its cash flows for the year then ended in accordance with Canadian generally accepted accounting principles.

Craig Keen Despatie Markell LLP

Cornwall, Ontario
April 27, 2011

CHARTERED ACCOUNTANTS
Licensed Public Accountants

RIDEAU ST. LAWRENCE DISTRIBUTION INC.

BALANCE SHEET

As at December 31, 2010

	2010	2009
ASSETS		
CURRENT		
Cash	**$ 661,035**	$ 511,914
Investments (Note 2)	**8,447**	8,447
Accounts receivable	**946,900**	1,053,336
Unbilled revenue	**1,371,719**	1,111,371
Inventory	**221,106**	200,906
Payments-in-lieu of corporate taxation	**19,932**	-
Prepaid expenses	**24,000**	42,844
	3,253,139	2,928,818
CAPITAL (Note 3)	**4,123,656**	4,115,106
NET REGULATORY ASSETS (Note 4)	**478,190**	1,165,899
	$ 7,854,985	$ 8,209,823
LIABILITIES		
CURRENT		
Temporary advances (Note 5)	**$ -**	$ 1,078,403
Accounts payable	**1,334,192**	1,500,406
Customer deposits	**79,000**	79,000
Payments-in-lieu of corporate taxation	**-**	306
Regulatory liabilities (Note 7)	**-**	14,508
Advances from related parties (Note 8)	**262,085**	311,512
Current portion of callable debt (Note 6)	**113,965**	-
Current portion of long-term debt (Note 9)	**70,940**	117,500
CURRENT LIABILITIES BEFORE CALLABLE DEBT	**1,860,182**	3,101,635
CALLABLE DEBT (Note 6)	**892,143**	-
	2,752,325	3,101,635
CUSTOMER DEPOSITS	**44,833**	51,127
LONG-TERM DEBT (Note 9)	**1,163,352**	1,234,322
ADVANCES FROM RELATED PARTY (Note 10)	**343,031**	343,031
	4,303,541	4,730,115
SHAREHOLDER'S EQUITY		
CAPITAL STOCK (Note 11)	**2,511,123**	2,511,123
RETAINED EARNINGS	**1,040,321**	968,585
	3,551,444	3,479,708
	$ 7,854,985	$ 8,209,823

APPROVED ON BEHALF OF THE BOARD:

_____________________ Director _____________________ Date

See Accompanying Notes

RIDEAU ST. LAWRENCE DISTRIBUTION INC.

____________________ Director ____________________ Date

RIDEAU ST. LAWRENCE DISTRIBUTION INC.

STATEMENT OF OPERATIONS AND RETAINED EARNINGS

For the year ended December 31, 2010

	2010	2009
REVENUE	**$ 11,108,483**	$ 10,962,543
COST OF ENERGY	**9,131,849**	8,978,754
GROSS MARGIN	**1,976,634**	1,983,789
OTHER INCOME		
Late payment and other charges	**149,345**	155,394
Rentals	**59,022**	37,235
Investment income	**8,019**	4,989
Interest improvement charges	**554**	25,118
Special programs	**32,070**	5,039
	249,010	227,775
TOTAL REVENUE NET OF COST OF ENERGY	**2,225,644**	2,211,564
EXPENSES		
Administration	**710,501**	676,115
Amortization	**260,560**	277,765
Billing and collecting	**423,105**	439,070
Interest on long-term debt	**100,180**	80,116
Operation maintenance	**524,711**	525,366
	2,019,057	1,998,432
INCOME BEFORE OTHER ITEMS	**206,587**	213,132
CONSERVATION AND DEMAND MANAGEMENT PROGRAM (Note 7)	**-**	50,798
GAIN ON EXCHANGE OF INVESTMENTS (Note 2)	**-**	2,414
INCOME BEFORE PAYMENTS-IN-LIEU OF CORPORATE TAXATION	**206,587**	266,344
(RECOVERY) PAYMENTS-IN-LIEU OF CORPORATE TAXATION (Note 12)	**4,851**	28,706
NET INCOME FOR THE YEAR	**201,736**	237,638
RETAINED EARNINGS, beginning of year	**968,585**	850,947
	1,170,321	1,088,585
DIVIDENDS	**130,000**	120,000
RETAINED EARNINGS, end of year	**$ 1,040,321**	$ 968,585

See Accompanying Notes

RIDEAU ST. LAWRENCE DISTRIBUTION INC.

STATEMENT OF CASH FLOWS

For the year ended December 31, 2010

		2010		2009
CASH FROM OPERATING ACTIVITIES				
Net income for the year	**$**	**201,736**	$	237,638
Items not affecting cash and equivalent				
Amortization		**260,560**		277,765
Gain on exchange of investments		**-**		(2,414)
Net changes in non-cash working capital balances				
Accounts receivable		**106,436**		(119,855)
Unbilled revenue		**(260,348)**		66,805
Inventory		**(20,200)**		(14,360)
Payments-in-lieu of corporate taxation		**(20,238)**		6,153
Prepaid expenses		**18,844**		19,131
Accounts payable		**(166,215)**		(133,220)
Regulatory liabilities		**(14,508)**		(4,806)
Advances from related parties		**(49,427)**		78,693
		56,640		411,530
CASH FROM (USED IN) INVESTING ACTIVITIES				
Net additions to capital assets		**(269,110)**		(537,330)
Decrease (increase) in net regulatory assets		**687,710**		(852,160)
		418,600		(1,389,490)
CASH FROM (USED IN) FINANCING ACTIVITIES				
Proceeds on callable debt		**1,078,403**		-
Payments on long-term debt and callable debt		**(189,825)**		(111,832)
Increase in customer deposits		**(6,294)**		(19,865)
Dividends paid		**(130,000)**		(120,000)
		752,284		(251,697)
INCREASE (DECREASE) IN CASH AND EQUIVALENT		**1,227,524**		(1,229,657)
CASH AND EQUIVALENT, beginning of year		**(566,489)**		663,168
CASH AND EQUIVALENT, end of year	**$**	**661,035**	$	(566,489)
REPRESENTED BY:				
Cash	**$**	**661,035**	$	511,914
Temporary advances		**-**		(1,078,403)
	$	**661,035**	$	(566,489)
Supplementary information:				
Interest paid	**$**	**100,180**	$	80,116
Payments-in-lieu of corporate taxation	**$**	**25,089**	$	22,553

See Accompanying Notes

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

The corporation follows Canadian generally accepted accounting principles for electrical utilities prescribed in the Ontario Energy Board's Accounting Procedures Handbook under the authority of Acts of the Province of Ontario and permitted by the Ontario Energy Board.

(a) Revenue recognition

Revenue from the sale of electricity is recorded when billed. Unbilled revenue is the accrual for electricity sold between the last billing date and the year-end date. The unbilled revenue adjustment is the change between the opening and closing balances of unbilled revenue and is included in revenue. Other income is recorded when services have been provided.

(b) Investments

Investments are recorded at lower of cost and market.

(c) Inventory

Inventory is valued at the lower of cost and net realizable value. Inventory is recorded using the average cost method.

(d) Capital assets and amortization

Capital assets are stated at acquisition cost and amortized using the straight-line method over five to forty years.

(e) Construction in progress

Capital items purchased for capital projects under construction are included in construction in progress and are not amortized until put into service.

(f) Contributions and grants in aid of construction

Contributions and grants received in aid of construction are recorded as a deduction against capital assets. The amount is amortized on the same basis as the asset constructed and credited to amortization expense. No amortization is recorded until the asset is in use.

(g) Customer deposits

Deposits taken to guarantee the payment of power bills or contract performance are shown as a current or long-term liability depending on the terms of repayment.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

(h) Use of estimates

The preparation of financial statements in conformity with Canadian generally accepted accounting principles 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 revenues and expenditures during the period. Actual results could differ from these estimates.

(i) Net regulatory assets and liabilities

The Ontario Energy Board provided accounting guidelines to include or exclude costs, revenues, losses or gains in the rates of a specific period, resulting in accounting recognition that differs from an unregulated company under Canadian generally accepted accounting principles. Such differences involves the application of rate-regulated accounting resulting in the recognition of regulatory assets and liabilities. Regulatory assets represent certain amounts receivable from future customers and costs that have been deferred for accounting purposes that are expected be recovered in future rates. Any regulatory liabilities represents funds received in different periods that have been deferred for accounting purposes that are expected to be adjusted in future rates or recognize as revenue in future periods. The corporation continually assess the likelihood of recovery of each of its regulatory assets and liabilities into the setting of future rates. If the corporation determines that these regulatory assets and liabilities will no longer form as part of future rates, the appropriate carrying amount would be included in the results of operations in the period that the assessment is made. Description of regulatory assets is as follows:

(i) Retail settlement variance accounts

Retail settlement variance accounts are the net of sales and expenses incurred by the corporation for retail settlement after the commencement of market opening on May 1, 2002. The net sales and expenses are to be recovered through future rate increases, under Article 490 of the Ontario Energy Board Accounting Procedures Handbook. A return of capital is capitalized on these amounts based on Article 490.

(ii) Smart meter capital cost variance account

Smart meter capital cost variance account is the net of smart meter capital expenses and related incremental operating, maintenance, amortization and administration expenses incurred by the corporation less accumulated billings to offset those costs. The net expenses are to be recovered through future rate increases under Article 490 of the Ontario Energy Board Accounting Procedures Handbook. A return of capital is capitalized on these amounts based on Article 490.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

(j) Corporate income and capital taxes

Under the Electricity Act, 1998, the corporation is required to make payments-in-lieu of corporate taxes to the Ontario Energy Finance corporation. These payments are calculated in accordance with the rules of computing income and taxable capital and other relevant amounts contained in the Income Tax Act (Canada) and the Corporation Tax Act (Ontario) as modified by the Electricity Act, 1998, and related regulations.

The corporation provides for payments-in-lieu of corporate income taxes relating to its regulated businesses using the taxes payable method as directed by the Ontario Energy Board. 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. When recorded future income taxes become payable, it is expected that they will be included in the rates approved by the Ontario Energy Board and recovered from the customers of the corporation at that time.

(k) Financial instruments

(i) Fair value of financial instruments

CICA Handbook Section 3855 establishes standards for recognizing and measuring financial assets, financial liabilities and derivatives. This standard prescribes when to recognize a financial instrument in the balance sheet and at what amount. Depending on the classification, fair value or cost based measures are used. The standard also prescribes the basis of presentation for gains and losses on financial instruments. Based on financial instrument classification, gains and losses on financial instruments are recognized in net income or as other comprehensive income.

The corporation has made the following classifications:

(i) Cash and investments are classified as "held for trading." They are measured at fair value and any gains or losses resulting from the re-measurement at end of each period are recognized in net income.

(ii) Accounts receivable and unbilled revenue are classified as "loans and receivables." They are recorded at cost, which upon their initial measurement is equal to their fair value. Subsequent measurements are recorded at amortized cost using the effective interest method.

(iii) Accounts payables and customer deposits are classified as "financial liabilities." They are recorded at their cost which upon their initial measurement is equal to their fair value. Subsequent measurements are recorded at amortized cost using the effective interest method.

The carrying amounts reported on the balance sheet for cash, investments, accounts receivable, unbilled revenue, accounts payable and customer deposits, approximate fair values due to the immediate and short-term maturities of these financial instruments.

The fair value of long-term debt, including the current portion, is based on rates currently available to the corporation with similar terms and maturities and approximates its carrying amounts as disclosed on the balance sheet.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

(k) Financial instruments (continued)

(ii) Concentration of credit risk

The corporation does not believe it is subject to any significant concentration of credit risk. Cash is in place with major financial institutions. Accounts receivable are the result of sales to individuals, corporations and not-for-profit organizations geographically concentrated within Eastern Ontario.

(iii) Comprehensive income - Section 1530

This Section describes the recognition and disclosure requirements with respect to comprehensive income. Comprehensive income consists of net income and other comprehensive income. Other comprehensive income represents the changes in the fair value of financial instruments which have not been included in net income. As the corporation did not have any adjustments to other comprehensive income during the year, this standard does not have an impact on the financial statements.

(l) International Financial Reporting Standards ("IFRS")

The Canadian Institute of Chartered Accountants announced that Canadian publicly accountable enterprises will be required to adopt International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("ISAB"), effective January 1, 2011. On September 10, 2010, the Canadian Accounting Standards Board ("AcSB") decided to permit rate-regulated entities to defer their IFRS implementation date to January 1, 2012. As such, the corporation will apply IFRS to its financial statements commencing January 1, 2012 with restatement of the amounts recorded on the opening IFRS balance sheet as at January 1, 2011 for comparative purposes. While the corporation is currently developing an implementation plan for the adoption of IFRS, the financial reporting impact of the transition to IFRS cannot be reasonably estimated at this time.

2. INVESTMENTS

The corporation exchanged its ownership of 18,000 units with a zero carrying value of Enerconnect Limited Partnership for 12,067 shares of Utilismart Corporation in December 2007. The shares of Utilismart Corporation are to be distributed to the corporation over a three year period. The corporation received no shares during the year for an accounting gain of $- (2009 - $2,414).

3. CAPITAL

	Cost	Accumulated Amortization	Net 2010	Net 2009
Land	**$ 84,205**	**$ -**	**$ 84,205**	$ 84,205
Buildings, leasehold improvements and fixtures	**91,084**	**8,847**	**82,237**	84,762
Distribution equipment	**5,772,398**	**1,702,991**	**4,069,407**	4,097,113
Tools and equipment	**132,984**	**97,597**	**35,387**	44,721
Computer hardware and software	**308,514**	**175,098**	**133,416**	99,741
Less: Contributions in aid of construction	**(360,987)**	**(79,991)**	**(280,996)**	(295,436)
	$ 6,028,198	**$ 1,904,542**	**$ 4,123,656**	$ 4,115,106

4. NET REGULATORY ASSETS

	2010	2009
Retail settlement variance accounts	**$ (468,978)**	$ 346,371
Smart meter capital cost variance account	**1,159,503**	819,528
Smart meter funding	**(212,335)**	-
	$ 478,190	$ 1,165,899

The Ontario Energy Board approved billing rates for the recovery of smart meter capital costs on a non-prudential basis of $2.00 per customer per month in 2010. The corporation will be applying for full cost recovery of the smart meter capital costs in future rate applications through the Ontario Energy Board.

5. TEMPORARY ADVANCES

	2010	2009
Demand loan	**$ -**	$ 833,403
Demand loan	**-**	245,000
	$ -	$ 1,078,403

Demand loans are non-revolving loans that bear interest at prime, interest only payments for first twelve months, maximum borrowing limit of $1,695,000 and are secured by a general security agreement dated May 20, 2009.

The corporation has an overdraft lending facility up to $750,000 that was not utilized as of December 31, 2010 with the same terms and conditions as the demand loans indicated in Note 6. The consolidated corporation provided a guarantee for the indebtedness up to $2,445,000 dated July 8, 2009.

6. CALLABLE DEBT

		2010		2009
Demand loan, interest at prime, monthly payments of $6,945 plus interest, due on demand, secured by equipment and general security agreement	**$**	**791,733**	$	-
Demand loan, interest at prime, monthly payments of $2,553 plus interest, due on demand, secured by vehicle and general security agreement		**214,375**		-
		1,006,108		-
Less: current portion		**113,965**		-
	$	**892,143**	$	-

The repayment of callable debt is as follows:

2011	$	113,965
2012		113,965
2013		113,965
2014		113,965
2015		113,965
Thereafter		436,283
	$	1,006,108

The demand loans are classified as callable debt obligations where the lender has or retains the right to demand full payment of the obligation over the course of the loans. These amounts would not be repaid within one year unless the lender exercises their right to demand payment in full.

7. REGULATORY LIABILITIES

Regulatory liabilities represents funds received for the transfer of Hydro One low voltage regulatory assets and the Conservation and Demand Management (C&DM) program. Costs are recorded against these funds when incurred. Transactions are summarized as follows:

		Hydro One Low Voltage Transfer		C&DM Program		2010		2009
Balance, beginning of year	**$**	**-**	**$**	**-**	**$**	**-**	$	19,314
Transfer of regulatory liabilities		**-**		**-**		**-**		38,718
Disbursements against regulatory liabilities		**-**		**-**		**-**		(43,524)
Balance, end of year	**$**	**-**	**$**	**-**	**$**	**-**	$	14,508

8. ADVANCES FROM RELATED PARTIES

		2010		2009
Advances from Rideau St. Lawrence Utilities Inc.	$	**248,383**	$	302,030
Advances from Rideau St. Lawrence Services Inc.		**13,702**		9,482
	$	**262,085**	$	311,512

The corporation is related to Rideau St. Lawrence Holdings Inc., Rideau St. Lawrence Utilities Inc., and Rideau St. Lawrence Services Inc. through common ownership. The corporation is a wholly-owned subsidiary of Rideau St. Lawrence Holdings Inc.

During the year, the corporation incurred administration, maintenance and other service expenditures with Rideau St. Lawrence Utilities Inc. Terms and conditions of transactions with Rideau St. Lawrence Utilities Inc. are covered by a Master Services Agreement dated November 1, 2000. Under this agreement, Rideau St. Lawrence Utilities Inc. provides specified services to the corporation on a fee for services basis.

9. LONG-TERM DEBT

		2010		2009
Loan payable, interest at 4.99%, payable in blended monthly payments of $10,096, due July 2011, secured by specific assets	$	**70,940**	$	188,470
Promissory note, Corporation of the Township of Edwardsburgh/Cardinal		**225,000**		225,000
Promissory note, Corporation of the Township of South Dundas		**938,352**		938,352
		1,234,292		1,351,822
Less: current portion		**70,940**		117,500
	$	**1,163,352**	$	1,234,322

The promissory notes bear interest at a rate determined by the Board of Directors not to exceed 7.25% per annum and are unsecured. Principal and interest shall be payable at the discretion of the Board of Directors. Interest rate at December 31, 2010 is 4.99%. The repayment of long-term debt is as follows:

2011	$	70,940
Thereafter		1,163,352
	$	1,234,292

10. ADVANCES FROM RELATED PARTY

Advances from related party are from Rideau St. Lawrence Holdings Inc., which bears no interest, has no specific terms of repayment, and are unsecured.

11. CAPITAL STOCK

Authorized -

Unlimited common shares

		2010		2009
Issued -				
2,511,123 common shares	**$**	**2,511,123**	$	2,511,123

12. PAYMENTS-IN-LIEU OF CORPORATE TAXATION

The provision for payments-in-lieu of corporate income taxes (PIL's) differs from the amount that would have been recorded using the combined Canadian Federal and Ontario statutory income tax rate. A reconciliation between the statutory and effective tax rates is provided as follows:

		2010		2009
Income before PIL's	**$**	**206,587**	$	266,344
Federal and Ontario statutory income tax rates		**16.00%**		16.50%
PIL's at statutory rate		**33,054**		43,947
Decrease resulting from:				
Temporary differences:				
Capital cost allowance in excess of amortization		**(26,319)**		(16,501)
Accounting gain on exchange of investments		**-**		(398)
Net temporary differences		**(26,319)**		(16,899)
Permanent differences:				
Corporate Minimum Tax (recovery)		**(2,204)**		6,266
Federal and Ontario Apprenticeship Training Tax Credits, net of tax		**320**		(4,608)
Net permanent differences		**(1,884)**		1,658
Provision for PIL's	**$**	**4,851**	$	28,706
Effective income tax rate		**2.35%**		10.78%

As at December 31, 2010, future income tax assets of $237,000 (2009 - $198,000), based on current income tax rates, have not been recorded.

13. CONTINGENCIES

The corporation entered into an irrevocable standing letter of credit with a financial institution. The letter of credit is a prudential support obligation required by all small distribution companies in Ontario for the Independent Electricity System Operator (IESO). The prudential support obligation is calculated at $681,809 which the corporation has not exercised as of December 31, 2010.

A class action lawsuit was filed against the corporation and other local electric distribution companies in Ontario by customers who were charged late payment penalties. A settlement was made in July 2010. The corporation's share of the lawsuit settlement is $18,392. This amount has been recorded as accounts payable in these financial statements. The corporation will be recovering these costs over a one year period staring May 1, 2011 as part of its rate base as approved by the Ontario Energy Board.

	Appendix 1D	
	Rideau St. Lawrence Distribution Inc.	**EB-2011-0274**
	Pro Forma Balance sheet - 2011	
Current Assets		**Total**
	Cash	$650,950
	Investment	8,447
	Accounts Receivable	1,090,000
	Unbilled Revenue	1,400,000
	Prepaid Expenses	25,000
	Total Current Assets	**$3,174,397**
	Inventory	**275,000**
Capital		
	Distribution Plant	$6,850,113
	General Plant	$741,403
	Accumulated Amortization	-$2,242,278
	Net Capital	**$5,349,238**
Net Regulatory Assets		**-$147,793**
Total Assets		**$8,650,842**
	Liabilities	
Current Liabilties		$3,437,197
	Non Current Liabilities	$75,000
	Long Term Debt	$2,056,630
	Shareholders Equity	$3,082,015
	Total Liabilities and Equity	**$8,650,842**
	Rideau St. Lawrence Distribution Inc.	**EB-2011-0274**
	Pro Forma Income Statement - 2011	
	Sales of Electricity	-$9,835,045
	Revenues from Services - Distribution	-$1,951,876
	Other Operating Revenues	-$171,953
	Gain of Loss on disposals	-$14,500
	Interest Income	-$12,000
	Total Revenue	**-$11,985,374**
	Power supply Expenses - total	$9,835,045
	Gross Margin	**-$2,150,329**
Distribution Expenses		
	Operations	$310,045
	Maintneance	$401,700
	Billing and Collecting	$422,000
	Community Relations	$3,500
	Administrative and General Expenses	$669,264
	Amortization Expense	$334,223
	Interest Expense	$102,295
	Taxes Other than Income Taxes	22400
	Income Taxes	-$46,251
	Net Income - (Gain)/Loss	**$68,849**

Appendix 1E

	Rideau St. Lawrence Distribution Inc.	**EB-2011-0274**
	Pro Forma Balance sheet - 2012	
Current Assets		**Total**
	Cash	$650,950
	Investment	8,447
	Accounts Receivable	1,090,000
	Unbilled Revenue	1,500,000
	Prepaid Expenses	25,000
	Total Current Assets	**$3,274,397**
	Inventory	**275,000**
Capital		
	Distribution Plant	$7,155,113
	General Plant	$821,403
	Accumulated Amortization	-$2,606,677
	Net Capital	**$5,369,839**
Net Regulatory Assets		**-$157,277**
Total Assets		**$8,761,959**
	Liabilities	
Current Liabilties		$3,406,189
	Non Current Liabilities	$65,000
	Long Term Debt	$1,594,917
	Shareholders Equity	$3,695,853
	Total Liabilities and Equity	**$8,761,960**

	Rideau St. Lawrence Distribution Inc.	**EB-2011-0274**
	Pro Forma Income Statement - 2012	
	Sales of Electricity	-$10,499,095
	Revenues from Services - Distribution	-$2,558,343
	Other Operating Revenues	-$165,329
	Gain of Loss on disposals	$0
	Interest Income	-$12,000
	Total Revenue	**-$13,234,767**
	Power supply Expenses - total	$10,499,095
	Gross Margin	**-$2,735,672**
Distribution Expenses		
	Operations	$309,662
	Maintneance	$411,374
	Billing and Collecting	$391,300
	Community Relations	$3,500
	Administrative and General Expenses	$775,892
	Amortization Expense	$340,980
	Interest Expense	$103,040
	Taxes Other than Income Taxes	$23,300
	Income Taxes	$39,129
	Net Income - (Gain)/Loss	**-$337,495**

RIDEAU ST. LAWRENCE DISTRIBUTION INC.

FINANCIAL STATEMENTS

December 31, 2009

RIDEAU ST. LAWRENCE DISTRIBUTION INC.

December 31, 2009

CONTENTS

Craig
Keen
Despatie
Markell
LLP

AUDITORS' REPORT

To the Shareholder of
Rideau St. Lawrence Distribution Inc.

We have audited the balance sheet of Rideau St. Lawrence Distribution Inc. as at December 31, 2009 and the statements of operations and 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 Rideau St. Lawrence Distribution Inc. as at December 31, 2009 and the results of its operations and retained earnings and its cash flows for the year then ended in accordance with Canadian generally accepted accounting principles.

Craig Keen Despatie Markell LLP

Craig Keen Despatie Markell LLP

CHARTERED ACCOUNTANTS
Licensed Public Accountants

Cornwall, Ontario
April 28, 2010

Robert W. Craig
B.COMM., FCA, (Ret.)
Brian D. Keen
B.COMM., CA
Michael D. Despatie
B.ADMIN., CA
Ross M. Markell
B.COMM., CA, TEP
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RIDEAU ST. LAWRENCE DISTRIBUTION INC.

BALANCE SHEET

As at December 31, 2009

	2009	2008
ASSETS		
CURRENT		
Cash	$ 511,914	$ 663,168
Investments (Note 2)	8,447	6,033
Accounts receivable	1,053,336	933,481
Unbilled revenue	1,111,371	1,178,176
Inventory	200,906	186,545
Payments-in-lieu of corporate taxation	-	5,847
Prepaid expenses	42,844	61,975
	2,928,818	3,035,225
CAPITAL (Note 3)	4,115,106	3,855,541
NET REGULATORY ASSETS (Note 4)	1,165,899	313,740
	$ 8,209,823	$ 7,204,506
LIABILITIES		
CURRENT		
Temporary advances (Note 5)	$ 1,078,403	-
Accounts payable	1,500,406	1,633,626
Customer deposits	79,000	79,000
Payments-in-lieu of corporate taxation	306	-
Regulatory liabilities (Note 6)	14,508	19,314
Advances from related parties (Note 7)	311,512	232,819
Current portion of long-term debt	117,500	109,500
	3,101,635	2,074,259
CUSTOMER DEPOSITS	51,127	70,992
LONG-TERM DEBT (Note 8)	1,234,322	1,354,154
ADVANCES FROM RELATED PARTY (Note 9)	343,031	343,031
	4,730,115	3,842,436
SHAREHOLDER'S EQUITY		
CAPITAL STOCK (Note 10)	2,511,123	2,511,123
RETAINED EARNINGS	968,585	850,947
	3,479,708	3,362,070
	$ 8,209,823	$ 7,204,506

APPROVED ON BEHALF OF THE BOARD:

____________________ Director

____________________ Director

____________________ Date

RIDEAU ST. LAWRENCE DISTRIBUTION INC.

STATEMENT OF OPERATIONS AND RETAINED EARNINGS

For the year ended December 31, 2009

	2009	2008
REVENUE	$ 10,962,543	$ 10,525,126
COST OF ENERGY	8,978,754	8,771,341
GROSS MARGIN	1,983,789	1,753,785
OTHER INCOME		
Late payment and other charges	155,394	167,178
Rentals	37,235	47,024
Investment income	4,989	26,583
Interest improvement charges	25,118	20,123
Gain on disposal of capital assets	-	4,100
Special programs	5,039	-
	227,775	265,008
TOTAL REVENUE NET OF COST OF ENERGY	2,211,564	2,018,793
EXPENSES		
Administration	676,115	651,530
Amortization	277,765	228,996
Billing and collecting	439,070	395,900
Interest on long-term debt	80,116	89,794
Operation maintenance	525,366	458,045
	1,998,432	1,824,265
INCOME BEFORE OTHER ITEMS	213,132	194,528
CONSERVATION AND DEMAND MANAGEMENT PROGRAM (Note 6)	50,798	-
RECOVERY OF PRE-MARKET OPENING COST OF POWER	-	40,870
GAIN ON EXCHANGE OF INVESTMENTS (Note 2)	2,414	2,413
INCOME BEFORE PAYMENTS-IN-LIEU OF CORPORATE TAXATION	266,344	237,811
PAYMENTS-IN-LIEU OF CORPORATE TAXATION (Note 11)	28,706	23,799
NET INCOME FOR THE YEAR	237,638	214,012
RETAINED EARNINGS, beginning of year	850,947	743,255
	1,088,585	957,267
DIVIDENDS	120,000	106,320
RETAINED EARNINGS, end of year	$ 968,585	$ 850,947

See Accompanying Notes

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

The corporation follows Canadian generally accepted accounting principles for electrical utilities prescribed in the Ontario Energy Board's Accounting Procedures Handbook under the authority of Acts of the Province of Ontario and permitted by the Ontario Energy Board.

(a) Revenue recognition

Revenue from the sale of electricity is recorded when billed. Unbilled revenue is the accrual for electricity sold between the last billing date and the year-end date. The unbilled revenue adjustment is the change between the opening and closing balances of unbilled revenue and is included in revenue. Other income is recorded when services have been provided.

(b) Investments

Investments are recorded at lower of cost and market.

(c) Inventory

Inventory is valued at the lower of cost and net realizable value. Inventory is recorded using the average cost method.

(d) Capital assets and amortization

Capital assets are stated at acquisition cost and amortized using the straight-line method over five to forty years.

(e) Construction in progress

Capital items purchased for capital projects under construction are included in construction in progress and are not amortized until put into service.

(f) Contributions and grants in aid of construction

Contributions and grants received in aid of construction are recorded as a deduction against capital assets. The amount is amortized on the same basis as the asset constructed and credited to amortization expense. No amortization is recorded until the asset is in use.

(g) Customer deposits

Deposits taken to guarantee the payment of power bills or contract performance are shown as a current or long-term liability depending on the terms of repayment.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

(h) Use of estimates

The preparation of financial statements in conformity with Canadian generally accepted accounting principles 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 revenues and expenditures during the period. Actual results could differ from these estimates.

(i) Net regulatory assets

(i) Retail settlement variance accounts

Retail settlement variance accounts are the net of sales and expenses incurred by the corporation for retail settlement after the commencement of market opening on May 1, 2002. The net sales and expenses are to be recovered through future rate increases, under Article 490 of the Ontario Energy Board Accounting Procedures Handbook. A return of capital is capitalized on these amounts based on Article 490.

(ii) Smart meter capital cost variance account

Smart meter capital cost variance account is the net of smart meter capital expenses and related incremental operating, maintenance, amortization and administration expenses incurred by the corporation less accumulated billings to offset those costs. The net expenses are to be recovered through future rate increases under Article 490 of the Ontario Energy Board Accounting Procedures Handbook. A return of capital is capitalized on these amounts based on Article 490.

In the absence of such regulations, these costs would have been expensed or included in capital assets when incurred, and no rate of return of capital would be capitalized under Canadian generally accepted accounting principles.

(j) Corporate income and capital taxes

Under the Electricity Act, 1998, the corporation is required to make payments-in-lieu of corporate taxes to the Ontario Energy Finance corporation. These payments are calculated in accordance with the rules of computing income and taxable capital and other relevant amounts contained in the Income Tax Act (Canada) and the Corporation Tax Act (Ontario) as modified by the Electricity Act, 1998, and related regulations.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

(k) Financial instruments (continued)

(iii) Comprehensive income - Section 1530

This Section describes the recognition and disclosure requirements with respect to comprehensive income. Comprehensive income consists of net income and other comprehensive income. Other comprehensive income represents the changes in the fair value of financial instruments which have not been included in net income. As the corporation did not have any adjustments to other comprehensive income during the year, this standard does not have an impact on the financial statements.

(l) International Financial Reporting Standards ("IFRS")

The Canadian Institute of Chartered Accountants announced that Canadian publicly accountable enterprises will be required to adopt International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("ISAB"), effective January 1, 2011. The corporation is considered a publicly accountable enterprise and will be required to adopt IFRS effective January 1, 2011 for its financial statements. While the corporation is currently developing an implementation plan for the adoption of IFRS, the financial reporting impact of the transition to IFRS cannot be reasonably estimated at this time.

2. INVESTMENTS

The corporation exchanged its ownership of 18,000 units with a zero carrying value of Enerconnect Limited Partnership for 12,067 shares of Utilismart Corporation in December 2007. The shares of Utilismart Corporation are to be distributed to the corporation over a three year period. The corporation received 2,414 shares during the year for an accounting gain of $2,414 (2008 - $2,413).

3. CAPITAL

	Cost	Accumulated Amortization	Net 2009	Net 2008
Land	$ 84,205	$ -	$ 84,205	$ 84,205
Buildings, leasehold improvements and fixtures	91,084	6,322	84,762	80,654
Distribution equipment	5,544,594	1,447,481	4,097,113	3,850,941
Tools and equipment	129,209	84,488	44,721	50,670
Computer hardware and software	270,985	171,244	99,741	92,103
Construction in progress	-	-	-	7,064
Less: Contributions in aid of construction	(360,987)	(65,551)	(295,436)	(310,096)
	$ 5,759,090	$ 1,643,984	$ 4,115,106	$ 3,855,541

4. NET REGULATORY ASSETS

	2009	2008
Retail settlement variance accounts	$ 346,371	$ 316,349
Smart meter capital cost variance account	819,528	(2,609)
	$ 1,165,899	$ 313,740

The Ontario Energy Board approved final billing rates subsequent to year-end for the recovery of retail settlement variance Group One accounts of $235,000 in 2010. The Ontario Energy Board also approved billing rates for the recovery of smart meter capital costs on a non-prudential basis from $1 to $2 per customer per month.

5. TEMPORARY ADVANCES

	2009	2008
Demand loan	$ 833,403	$ -
Demand loan	245,000	-
	$ 1,078,403	$ -

Demand loans are non-revolving loans that bear interest at prime, interest only payments for first twelve months, maximum borrowing limit of $1,695,000 and are secured by a general security agreement dated May 20, 2009. The corporation has an overdraft lending facility up to $750,000 that was not utilized as of December 31, 2009 with the same terms and conditions as the demand loans indicated above. Rideau St. Lawrence Holdings Inc. provided a guarantee for indebtedness of the corporation up to $2,445,000 dated July 9, 2009. Management's intention is to refinance the temporary advances with long-term fixed rate term loans in 2010 with principal repayment terms amortized over a maximum period of ten years.

6. REGULATORY LIABILITIES

Regulatory liabilities represents funds received for the transfer of Hydro One low voltage regulatory assets and the Conservation and Demand Management (C&DM) program. Costs are recorded against these funds when incurred. Transactions are summarized as follows:

	Hydro One Low Voltage Transfer	C&DM Program	2009	2008
Balance, beginning of year	$ 19,314	$ -	$ 19,314	$ 174,285
Transfer of regulatory liabilities	38,718	-	38,718	-
Disbursements against regulatory liabilities	(43,524)	-	(43,524)	(154,971)
Balance, end of year	$ 14,508	$ -	$ 14,508	$ 19,314

The Conservation and Demand Management (C&DM) program was completed in 2008 of which $50,798 was allocated to capital asset additions. The revenue allocated to the capital asset additions is recorded as income in 2009.

7. ADVANCES FROM RELATED PARTIES

	2009	2008
Advances from Rideau St. Lawrence Utilities Inc.	$ 302,030	$ 228,257
Advances from Rideau St. Lawrence Services Inc.	9,482	4,562
	$ 311,512	$ 232,819

The corporation is related to Rideau St. Lawrence Holdings Inc., Rideau St. Lawrence Utilities Inc., and Rideau St. Lawrence Services Inc. through common ownership. The corporation is a wholly-owned subsidiary of Rideau St. Lawrence Holdings Inc.

During the year, the corporation incurred administration, maintenance and other service expenditures with Rideau St. Lawrence Utilities Inc. Terms and conditions of transactions with Rideau St. Lawrence Utilities Inc. are covered by a Master Services Agreement dated November 1, 2000. Under this agreement, Rideau St. Lawrence Utilities Inc. provides specified services to the corporation on a fee for services basis.

8. LONG-TERM DEBT

	2009	2008
Loan payable, interest at 4.99%, payable in blended monthly payments of $10,096, due July 2011, secured by specific assets	$ **188,470**	$ 300,302
Promissory note, Corporation of the Township of Edwardsburgh/Cardinal	**225,000**	225,000
Promissory note, Corporation of the Township of South Dundas	**938,352**	938,352
	1,351,822	1,463,654
Less: current portion	**117,500**	109,500
	$ **1,234,322**	$ 1,354,154

The promissory notes bear interest at a rate determined by the Board of Directors not to exceed 7.25% per annum and are unsecured. Principal and interest shall be payable at the discretion of the Board of Directors. Interest rate at December 31, 2009 is 4.99%. The repayment of long-term debt is as follows:

2010	$ 117,500
2011	70,970
Thereafter	1,163,352
	$ 1,351,822

9. ADVANCES FROM RELATED PARTY

Advances from related party are from Rideau St. Lawrence Holdings Inc., which bears no interest, has no specific terms of repayment, and are unsecured.

10. CAPITAL STOCK

Authorized -

Unlimited common shares

	2009	2008
Issued -		
2,511,123 common shares	$ **2,511,123**	$ 2,511,123

11. PAYMENTS-IN-LIEU OF CORPORATE TAXATION

The provision for payments-in-lieu of corporate income taxes (PIL's) differs from the amount that would have been recorded using the combined Canadian Federal and Ontario statutory income tax rate. A reconciliation between the statutory and effective tax rates is provided as follows:

	2009	2008
Income before PIL's	$ **266,344**	$ 237,811
Federal and Ontario statutory income tax rates	**16.50 %**	16.50 %
PIL's at statutory rate	**43,947**	39,239
Decrease resulting from:		
Temporary differences:		
Capital cost allowance in excess of amortization	**(16,501)**	(11,448)
Accounting gain on disposal of capital assets	**-**	(677)
Accounting gain on exchange of investments	**(398)**	(398)
Net temporary differences	**(16,899)**	(12,523)
Permanent differences:		
Corporate Minimum Tax (recovery)	**6,266**	(88)
Apprenticeship Training Tax Credits	**(4,608)**	(2,829)
Net permanent differences	**1,658**	(2,917)
Provision for PIL's	$ **28,706**	$ 23,799
Effective income tax rate	**10.78 %**	10.01 %

As at December 31, 2009, future income tax assets of $198,000 (2008 - $215,000), based on current income tax rates, have not been recorded.

12. CONTINGENCIES

The corporation entered into an irrevocable standing letter of credit with a financial institution. The letter of credit is a prudential support obligation required by all small distribution companies in Ontario for the Independent Electricity System Operator (IESO). The prudential support obligation is calculated at $521,467, which the corporation has not exercised as of December 31, 2009.

A class action lawsuit was filed against the corporation and other local electric distribution companies in Ontario by customers who were charged late payment penalties. No settlement have been reached as of April 28, 2010. In management's opinion, the potential settlement is not significant.

RIDEAU ST. LAWRENCE DISTRIBUTION INC.

FINANCIAL STATEMENTS

December 31, 2010

Craig Keen Despatie Markell LLP

RIDEAU ST. LAWRENCE DISTRIBUTION INC.

December 31, 2010

CONTENTS

Craig
Keen
Despatie
Markell
LLP

INDEPENDENT AUDITORS' REPORT

To the Shareholders of
Rideau St. Lawrence Distribution Inc.

We have audited the accompanying financial statements of Rideau St. Lawrence Distribution Inc., which comprise the balance sheet as at December 31, 2010, and the statement of operations and retained earnings and cash flows for the year then ended, and a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Financial Statements

Management is responsible for the preparation and fair presentation of these financial statements in accordance with Canadian generally accepted accounting principles and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibility

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 comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditors' judgement, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditors considers internal control relevant to the entity's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by administration, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the financial statements present fairly, in all material respects, the balance sheet of Rideau St. Lawrence Distribution Inc. as at December 31, 2010, and its statement of income and retained earnings and its cash flows for the year then ended in accordance with Canadian generally accepted accounting principles.

Craig Keen Despatie Markell LLP

Craig Keen Despatie Markell LLP

CHARTERED ACCOUNTANTS
Licensed Public Accountants

Cornwall, Ontario
April 27, 2011

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RIDEAU ST. LAWRENCE DISTRIBUTION INC.

BALANCE SHEET

As at December 31, 2010

	2010	2009
ASSETS		
CURRENT		
Cash	$ 661,035	$ 511,914
Investments (Note 2)	8,447	8,447
Accounts receivable	946,900	1,053,336
Unbilled revenue	1,371,719	1,111,371
Inventory	221,106	200,906
Payments-in-lieu of corporate taxation	19,932	-
Prepaid expenses	24,000	42,844
	3,253,139	2,928,818
CAPITAL (Note 3)	4,123,656	4,115,106
NET REGULATORY ASSETS (Note 4)	478,190	1,165,899
	$ 7,854,985	$ 8,209,823
LIABILITIES		
CURRENT		
Temporary advances (Note 5)	$ -	$ 1,078,403
Accounts payable	1,334,192	1,500,406
Customer deposits	79,000	79,000
Payments-in-lieu of corporate taxation	-	306
Regulatory liabilities (Note 7)	-	14,508
Advances from related parties (Note 8)	262,085	311,512
Current portion of callable debt (Note 6)	113,965	-
Current portion of long-term debt (Note 9)	70,940	117,500
CURRENT LIABILITIES BEFORE CALLABLE DEBT	1,860,182	3,101,635
CALLABLE DEBT (Note 6)	892,143	-
	2,752,325	3,101,635
CUSTOMER DEPOSITS	44,833	51,127
LONG-TERM DEBT (Note 9)	1,163,352	1,234,322
ADVANCES FROM RELATED PARTY (Note 10)	343,031	343,031
	4,303,541	4,730,115
SHAREHOLDER'S EQUITY		
CAPITAL STOCK (Note 11)	2,511,123	2,511,123
RETAINED EARNINGS	1,040,321	968,585
	3,551,444	3,479,708
	$ 7,854,985	$ 8,209,823

APPROVED ON BEHALF OF THE BOARD:

________ Director   27 April 2011 Date

________ Director   27 April 2011 Date

See Accompanying Notes

RIDEAU ST. LAWRENCE DISTRIBUTION INC.

STATEMENT OF OPERATIONS AND RETAINED EARNINGS

For the year ended December 31, 2010

	2010	2009
REVENUE	$ **11,108,483**	$ 10,962,543
COST OF ENERGY	9,131,849	8,978,754
GROSS MARGIN	1,976,634	1,983,789
OTHER INCOME		
Late payment and other charges	**149,345**	155,394
Rentals	**59,022**	37,235
Investment income	**8,019**	4,989
Interest improvement charges	**554**	25,118
Special programs	**32,070**	5,039
	249,010	227,775
TOTAL REVENUE NET OF COST OF ENERGY	**2,225,644**	2,211,564
EXPENSES		
Administration	**710,501**	676,115
Amortization	**260,560**	277,765
Billing and collecting	**423,105**	439,070
Interest on long-term debt	**100,180**	80,116
Operation maintenance	**524,711**	525,366
	2,019,057	1,998,432
INCOME BEFORE OTHER ITEMS	**206,587**	213,132
CONSERVATION AND DEMAND MANAGEMENT PROGRAM (Note 7)	-	50,798
GAIN ON EXCHANGE OF INVESTMENTS (Note 2)	-	2,414
INCOME BEFORE PAYMENTS-IN-LIEU OF CORPORATE TAXATION	**206,587**	266,344
(RECOVERY) PAYMENTS-IN-LIEU OF CORPORATE TAXATION (Note 12)	**4,851**	28,706
NET INCOME FOR THE YEAR	**201,736**	237,638
RETAINED EARNINGS, beginning of year	**968,585**	850,947
	1,170,321	1,088,585
DIVIDENDS	**130,000**	120,000
RETAINED EARNINGS, end of year	$ **1,040,321**	$ 968,585

See Accompanying Notes

RIDEAU ST. LAWRENCE DISTRIBUTION INC.

STATEMENT OF CASH FLOWS

For the year ended December 31, 2010

		2010		2009
CASH FROM OPERATING ACTIVITIES				
Net income for the year	$	**201,736**	$	237,638
Items not affecting cash and equivalent				
Amortization		**260,560**		277,765
Gain on exchange of investments		-		(2,414)
Net changes in non-cash working capital balances				
Accounts receivable		**106,436**		(119,855)
Unbilled revenue		**(260,348)**		66,805
Inventory		**(20,200)**		(14,360)
Payments-in-lieu of corporate taxation		**(20,238)**		6,153
Prepaid expenses		**18,844**		19,131
Accounts payable		**(166,215)**		(133,220)
Regulatory liabilities		**(14,508)**		(4,806)
Advances from related parties		**(49,427)**		78,693
		56,640		411,530
CASH FROM (USED IN) INVESTING ACTIVITIES				
Net additions to capital assets		**(269,110)**		(537,330)
Decrease (increase) in net regulatory assets		**687,710**		(852,160)
		418,600		(1,389,490)
CASH FROM (USED IN) FINANCING ACTIVITIES				
Proceeds on callable debt		**1,078,403**		-
Payments on long-term debt and callable debt		**(189,825)**		(111,832)
Increase in customer deposits		**(6,294)**		(19,865)
Dividends paid		**(130,000)**		(120,000)
		752,284		(251,697)
INCREASE (DECREASE) IN CASH AND EQUIVALENT		**1,227,524**		(1,229,657)
CASH AND EQUIVALENT, beginning of year		**(566,489)**		663,168
CASH AND EQUIVALENT, end of year	$	**661,035**	$	(566,489)
REPRESENTED BY:				
Cash	$	**661,035**	$	511,914
Temporary advances		-		(1,078,403)
	$	**661,035**	$	(566,489)
Supplementary information:				
Interest paid	$	**100,180**	$	80,116
Payments-in-lieu of corporate taxation	$	**25,089**	$	22,553

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

The corporation follows Canadian generally accepted accounting principles for electrical utilities prescribed in the Ontario Energy Board's Accounting Procedures Handbook under the authority of Acts of the Province of Ontario and permitted by the Ontario Energy Board.

(a) Revenue recognition

Revenue from the sale of electricity is recorded when billed. Unbilled revenue is the accrual for electricity sold between the last billing date and the year-end date. The unbilled revenue adjustment is the change between the opening and closing balances of unbilled revenue and is included in revenue. Other income is recorded when services have been provided.

(b) Investments

Investments are recorded at lower of cost and market.

(c) Inventory

Inventory is valued at the lower of cost and net realizable value. Inventory is recorded using the average cost method.

(d) Capital assets and amortization

Capital assets are stated at acquisition cost and amortized using the straight-line method over five to forty years.

(e) Construction in progress

Capital items purchased for capital projects under construction are included in construction in progress and are not amortized until put into service.

(f) Contributions and grants in aid of construction

Contributions and grants received in aid of construction are recorded as a deduction against capital assets. The amount is amortized on the same basis as the asset constructed and credited to amortization expense. No amortization is recorded until the asset is in use.

(g) Customer deposits

Deposits taken to guarantee the payment of power bills or contract performance are shown as a current or long-term liability depending on the terms of repayment.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

(h) Use of estimates

The preparation of financial statements in conformity with Canadian generally accepted accounting principles 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 revenues and expenditures during the period. Actual results could differ from these estimates.

(i) Net regulatory assets and liabilities

The Ontario Energy Board provided accounting guidelines to include or exclude costs, revenues, losses or gains in the rates of a specific period, resulting in accounting recognition that differs from an unregulated company under Canadian generally accepted accounting principles. Such differences involves the application of rate-regulated accounting resulting in the recognition of regulatory assets and liabilities. Regulatory assets represent certain amounts receivable from future customers and costs that have been deferred for accounting purposes that are expected be recovered in future rates. Any regulatory liabilities represents funds received in different periods that have been deferred for accounting purposes that are expected to be adjusted in future rates or recognize as revenue in future periods. The corporation continually assess the likelihood of recovery of each of its regulatory assets and liabilities into the setting of future rates. If the corporation determines that these regulatory assets and liabilities will no longer form as part of future rates, the appropriate carrying amount would be included in the results of operations in the period that the assessment is made. Description of regulatory assets is as follows:

(i) Retail settlement variance accounts

Retail settlement variance accounts are the net of sales and expenses incurred by the corporation for retail settlement after the commencement of market opening on May 1, 2002. The net sales and expenses are to be recovered through future rate increases, under Article 490 of the Ontario Energy Board Accounting Procedures Handbook. A return of capital is capitalized on these amounts based on Article 490.

(ii) Smart meter capital cost variance account

Smart meter capital cost variance account is the net of smart meter capital expenses and related incremental operating, maintenance, amortization and administration expenses incurred by the corporation less accumulated billings to offset those costs. The net expenses are to be recovered through future rate increases under Article 490 of the Ontario Energy Board Accounting Procedures Handbook. A return of capital is capitalized on these amounts based on Article 490.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

(j) Corporate income and capital taxes

Under the Electricity Act, 1998, the corporation is required to make payments-in-lieu of corporate taxes to the Ontario Energy Finance corporation. These payments are calculated in accordance with the rules of computing income and taxable capital and other relevant amounts contained in the Income Tax Act (Canada) and the Corporation Tax Act (Ontario) as modified by the Electricity Act, 1998, and related regulations.

The corporation provides for payments-in-lieu of corporate income taxes relating to its regulated businesses using the taxes payable method as directed by the Ontario Energy Board. 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. When recorded future income taxes become payable, it is expected that they will be included in the rates approved by the Ontario Energy Board and recovered from the customers of the corporation at that time.

(k) Financial instruments

(i) Fair value of financial instruments

CICA Handbook Section 3855 establishes standards for recognizing and measuring financial assets, financial liabilities and derivatives. This standard prescribes when to recognize a financial instrument in the balance sheet and at what amount. Depending on the classification, fair value or cost based measures are used. The standard also prescribes the basis of presentation for gains and losses on financial instruments. Based on financial instrument classification, gains and losses on financial instruments are recognized in net income or as other comprehensive income.

The corporation has made the following classifications:

(i) Cash and investments are classified as "held for trading." They are measured at fair value and any gains or losses resulting from the re-measurement at end of each period are recognized in net income.

(ii) Accounts receivable and unbilled revenue are classified as "loans and receivables." They are recorded at cost, which upon their initial measurement is equal to their fair value. Subsequent measurements are recorded at amortized cost using the effective interest method.

(iii) Accounts payables and customer deposits are classified as "financial liabilities." They are recorded at their cost which upon their initial measurement is equal to their fair value. Subsequent measurements are recorded at amortized cost using the effective interest method.

The carrying amounts reported on the balance sheet for cash, investments, accounts receivable, unbilled revenue, accounts payable and customer deposits, approximate fair values due to the immediate and short-term maturities of these financial instruments.

The fair value of long-term debt, including the current portion, is based on rates currently available to the corporation with similar terms and maturities and approximates its carrying amounts as disclosed on the balance sheet.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

(k) Financial instruments (continued)

(ii) Concentration of credit risk

The corporation does not believe it is subject to any significant concentration of credit risk. Cash is in place with major financial institutions. Accounts receivable are the result of sales to individuals, corporations and not-for-profit organizations geographically concentrated within Eastern Ontario.

(iii) Comprehensive income - Section 1530

This Section describes the recognition and disclosure requirements with respect to comprehensive income. Comprehensive income consists of net income and other comprehensive income. Other comprehensive income represents the changes in the fair value of financial instruments which have not been included in net income. As the corporation did not have any adjustments to other comprehensive income during the year, this standard does not have an impact on the financial statements.

(l) International Financial Reporting Standards ("IFRS")

The Canadian Institute of Chartered Accountants announced that Canadian publicly accountable enterprises will be required to adopt International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("ISAB"), effective January 1, 2011. On September 10, 2010, the Canadian Accounting Standards Board ("AcSB") decided to permit rate-regulated entities to defer their IFRS implementation date to January 1, 2012. As such, the corporation will apply IFRS to its financial statements commencing January 1, 2012 with restatement of the amounts recorded on the opening IFRS balance sheet as at January 1, 2011 for comparative purposes. While the corporation is currently developing an implementation plan for the adoption of IFRS, the financial reporting impact of the transition to IFRS cannot be reasonably estimated at this time.

2. INVESTMENTS

The corporation exchanged its ownership of 18,000 units with a zero carrying value of Enerconnect Limited Partnership for 12,067 shares of Utilismart Corporation in December 2007. The shares of Utilismart Corporation are to be distributed to the corporation over a three year period. The corporation received no shares during the year for an accounting gain of $- (2009 - $2,414).

3. CAPITAL

	Cost	Accumulated Amortization	Net 2010	Net 2009
Land	$ 84,205	$ -	$ 84,205	$ 84,205
Buildings, leasehold improvements and fixtures	91,084	8,847	82,237	84,762
Distribution equipment	5,772,398	1,702,991	4,069,407	4,097,113
Tools and equipment	132,984	97,597	35,387	44,721
Computer hardware and software	308,514	175,098	133,416	99,741
Less: Contributions in aid of construction	(360,987)	(79,991)	(280,996)	(295,436)
	$ 6,028,198	$ 1,904,542	$ 4,123,656	$ 4,115,106

4. NET REGULATORY ASSETS

	2010	2009
Retail settlement variance accounts	$ (468,978)	$ 346,371
Smart meter capital cost variance account	1,159,503	819,528
Smart meter funding	(212,335)	-
	$ 478,190	$ 1,165,899

The Ontario Energy Board approved billing rates for the recovery of smart meter capital costs on a non-prudential basis of $2.00 per customer per month in 2010. The corporation will be applying for full cost recovery of the smart meter capital costs in future rate applications through the Ontario Energy Board.

5. TEMPORARY ADVANCES

	2010	2009
Demand loan	$ -	$ 833,403
Demand loan	-	245,000
	$ -	$ 1,078,403

Demand loans are non-revolving loans that bear interest at prime, interest only payments for first twelve months, maximum borrowing limit of $1,695,000 and are secured by a general security agreement dated May 20, 2009.

The corporation has an overdraft lending facility up to $750,000 that was not utilized as of December 31, 2010 with the same terms and conditions as the demand loans indicated in Note 6. The consolidated corporation provided a guarantee for the indebtedness up to $2,445,000 dated July 8, 2009.

6. CALLABLE DEBT

		2010		2009
Demand loan, interest at prime, monthly payments of $6,945 plus interest, due on demand, secured by equipment and general security agreement	$	**791,733**	$	-
Demand loan, interest at prime, monthly payments of $2,553 plus interest, due on demand, secured by vehicle and general security agreement		**214,375**		-
		1,006,108		-
Less: current portion		**113,965**		-
	$	**892,143**	$	-

The repayment of callable debt is as follows:

2011	$	113,965
2012		113,965
2013		113,965
2014		113,965
2015		113,965
Thereafter		436,283
	$	1,006,108

The demand loans are classified as callable debt obligations where the lender has or retains the right to demand full payment of the obligation over the course of the loans. These amounts would not be repaid within one year unless the lender exercises their right to demand payment in full.

7. REGULATORY LIABILITIES

Regulatory liabilities represents funds received for the transfer of Hydro One low voltage regulatory assets and the Conservation and Demand Management (C&DM) program. Costs are recorded against these funds when incurred. Transactions are summarized as follows:

		Hydro One Low Voltage Transfer		C&DM Program		2010		2009
Balance, beginning of year	$	-	$	-	$	-	$	19,314
Transfer of regulatory liabilities		-		-		-		38,718
Disbursements against regulatory liabilities		-		-		-		(43,524)
Balance, end of year	$	-	$	-	$	-	$	14,508

8. ADVANCES FROM RELATED PARTIES

	2010	2009
Advances from Rideau St. Lawrence Utilities Inc.	$ **248,383**	$ 302,030
Advances from Rideau St. Lawrence Services Inc.	**13,702**	9,482
	$ **262,085**	$ 311,512

The corporation is related to Rideau St. Lawrence Holdings Inc., Rideau St. Lawrence Utilities Inc., and Rideau St. Lawrence Services Inc. through common ownership. The corporation is a wholly-owned subsidiary of Rideau St. Lawrence Holdings Inc.

During the year, the corporation incurred administration, maintenance and other service expenditures with Rideau St. Lawrence Utilities Inc. Terms and conditions of transactions with Rideau St. Lawrence Utilities Inc. are covered by a Master Services Agreement dated November 1, 2000. Under this agreement, Rideau St. Lawrence Utilities Inc. provides specified services to the corporation on a fee for services basis.

9. LONG-TERM DEBT

	2010	2009
Loan payable, interest at 4.99%, payable in blended monthly payments of $10,096, due July 2011, secured by specific assets	$ **70,940**	$ 188,470
Promissory note, Corporation of the Township of Edwardsburgh/Cardinal	**225,000**	225,000
Promissory note, Corporation of the Township of South Dundas	**938,352**	938,352
	1,234,292	1,351,822
Less: current portion	**70,940**	117,500
	$ **1,163,352**	$ 1,234,322

The promissory notes bear interest at a rate determined by the Board of Directors not to exceed 7.25% per annum and are unsecured. Principal and interest shall be payable at the discretion of the Board of Directors. Interest rate at December 31, 2010 is 4.99%. The repayment of long-term debt is as follows:

2011	$ 70,940
Thereafter	1,163,352
	$ 1,234,292

10. ADVANCES FROM RELATED PARTY

Advances from related party are from Rideau St. Lawrence Holdings Inc., which bears no interest, has no specific terms of repayment, and are unsecured.

11. CAPITAL STOCK

Authorized -

Unlimited common shares

		2010		2009
Issued -				
2,511,123 common shares	$	**2,511,123**	$	2,511,123

12. PAYMENTS-IN-LIEU OF CORPORATE TAXATION

The provision for payments-in-lieu of corporate income taxes (PIL's) differs from the amount that would have been recorded using the combined Canadian Federal and Ontario statutory income tax rate. A reconciliation between the statutory and effective tax rates is provided as follows:

		2010		2009
Income before PIL's	$	**206,587**	$	266,344
Federal and Ontario statutory income tax rates		**16.00 %**		16.50 %
PIL's at statutory rate		**33,054**		43,947
Decrease resulting from:				
Temporary differences:				
Capital cost allowance in excess of amortization		**(26,319)**		(16,501)
Accounting gain on exchange of investments		**-**		(398)
Net temporary differences		**(26,319)**		(16,899)
Permanent differences:				
Corporate Minimum Tax (recovery)		**(2,204)**		6,266
Federal and Ontario Apprenticeship Training Tax Credits, net of tax		**320**		(4,608)
Net permanent differences		**(1,884)**		1,658
Provision for PIL's	$	**4,851**	$	28,706
Effective income tax rate		**2.35 %**		10.78 %

As at December 31, 2010, future income tax assets of $237,000 (2009 - $198,000), based on current income tax rates, have not been recorded.

13. CONTINGENCIES

The corporation entered into an irrevocable standing letter of credit with a financial institution. The letter of credit is a prudential support obligation required by all small distribution companies in Ontario for the Independent Electricity System Operator (IESO). The prudential support obligation is calculated at $681,809 which the corporation has not exercised as of December 31, 2010.

A class action lawsuit was filed against the corporation and other local electric distribution companies in Ontario by customers who were charged late payment penalties. A settlement was made in July 2010. The corporation's share of the lawsuit settlement is $18,392. This amount has been recorded as accounts payable in these financial statements. The corporation will be recovering these costs over a one year period staring May 1, 2011 as part of its rate base as approved by the Ontario Energy Board.

<u>Exhibit 2</u> <u>Rate Base</u>

Schedule	**Contents of Schedule**
1.0	RATE BASE OVERVIEW
2.0	VARIANCE ANALYSIS ON RATE BASE
3.0	MODIFIED IFRS
4.0	STRANDED ASSETS
5.0	CONTINUITY STATEMENTS
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11.0	CAPITALIZATION POLICY
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Appendix 2A Green Energy Plan

1.0 RATE BASE OVERVIEW

The rate base used for the purpose of calculating the revenue requirement is the average of the net fixed asset balances at the beginning and the end of the 2012 Test Year, plus the working capital allowance.

The net fixed assets include those distribution assets that are associated with activities that enable the conveyance of electricity for distribution purposes.

Controllable expenses include operations and maintenance, billing and collecting, and administration expenses.

RSL has calculated its Test Year Rate Base as $7,221,657 based on modified IFRS. RSL has provided a summary of its rate base calculations, including Eligible Distribution Expenses (OM&A plus Taxes Other than Income Taxes), Power Supply Expenses, Working Capital total, Working Capital Allowance @ 15%, and the Average Net Book Value (NBV) for Fixed assets, for the years 2008 Board Approved, 2008 Actual, 2009 Actual, 2010 Actual, 2011 Bridge Year and 2012 Test Year in Table 2.1 below.

As part of the Rate Base, OM&A is included in Table 2.1. Detailed Variance Analysis for OM&A is provided in Exhibit 4.

RSL has not completed a lead-lag study. The working capital allowance is based on 15% of cost of power and controllable expenses in accordance with the Filing Requirements and consistent with Board Decisions on other distribution rate applications where a utility specific lead-lag study had not been completed.

RSL has provided Fixed Assets, Accumulated Depreciation, and the resulting NBV in modified IFRS format for 2011 Bridge and 2012 Test years.

Table 2.1

Summary of Rate Base

Distribution Expenses	2008 Board Approved	Actual 2008	Actual 2009	Actual 2010	2011 Bridge MIFRS	2012 Test MIFRS
Distribution Expenses - Operation	189,708	189,498	232,774	178,302	310,045	309,662
Distribution Expenses - Maintenance	401,986	268,548	292,592	346,408	401,700	411,374
Billing and Collecting	363,576	395,414	429,851	422,655	422,000	391,300
Community Relations	254	486	9,220	450	3,500	3,500
Administrative & General Expenses	631,102	629,125	653,416	695,208	669,264	775,892
Taxes Other than Income Taxes	22,426	21,292	20,755	21,558	22,400	23,300
Less: Capital Taxes within 6105	0	0	0	0	0	0
Total Eligible Distribution Expenses	1,609,052	1,504,363	1,638,607	1,664,583	1,828,909	1,915,028
Power Supply Expenses	2008 Board Approved	Actual 2008	Actual 2009	Actual 2010	2011 Bridge MIFRS	2012 Test MIFRS
Power Purchased	6,966,881	6,728,403	7,132,007	7,174,199	7,727,381	8,370,389
Wholesale Market Services	770,074	620,540	582,597	484,015	746,769	711,086
Charges - NW	564748	592,958	540,602	616,962	660,850	681,913
Charges - CN	525,187	539,938	483,115	542,832	517,418	554,698
Rural Rate Assistance	12,004	121,335	140,879	151,571	0	0
Low Voltage Charges	192735	168,168	99,554	162,271	182,627	181,008
Power Supply Expenses - Total	9,031,629	8,771,341	8,978,754	9,131,849	9,835,045	10,499,095
Working Capital Total	10,640,681	10,275,704	10,617,362	10,796,432	11,663,954	12,414,122
Working Capital Allowance @ 15%	1,596,102	1,541,356	1,592,604	1,619,465	1,749,593	1,862,118
Fixed Assets	2008 Board Approved	Actual 2008	Actual 2009	Actual 2010	2011 Bridge MIFRS	2012 Test MIFRS
Gross Fixed Assets	5,237,872	5,216,079	5,759,089	7,170,977	7,591,516	7,976,516
Accumulated Depreciation	1,377,847	1,367,600	1,643,983	2,023,384	2,242,278	2,606,677
Net Book Value	3,860,025	3,848,480	4,115,106	5,147,593	5,349,238	5,369,839
Average Net book Value	3,678,402	3,674,703	3,981,793	4,631,349	5,248,415	5,359,538
Rate Base	5,274,504	5,216,059	5,574,397	6,250,814	6,998,008	7,221,657

2.0 VARIANCE ANALYSIS ON RATE BASE

Rate Base Continuity Statement variances for the 2008 Board Approved, 2009 Actuals, 2010 Actuals, 2011 Bridge Year and 2012 Test Year are shown below in Table 2.2.

RSL notes that the 2008 Board Approved rate base was determined through RSL's 2008 Cost of Service Application (EB-2007-0762), the first year a forward test year was used.

The 2012 Base Revenue Requirement for RSL, calculated under modified IFRS, is $2,528,129

In accordance with the report EB-2007-0673 - "Supplementary Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity distributors of September 17, 2008" RSL's materiality threshold is $50,000 as the Revenue Requirement is under $10 million.

2008 Board Approved $5,274,504 vs. 2008 Actual $5,216,059 – Variance ($58,445):

2008 OM&A actual costs were under the Board Approved level for Distribution Expenses – Maintenance by $133,438, due to the loss of Journeyman Lineman, and the Operations Manager for a few months, as detailed in Exhibit 4.

The actual kWh's billed in 2008 of 111,785,106, was under the 2008 Board Approved amount of 118,759,464, by 6,974,358 kWh's. This is the main reason the 2008 Actual Working Capital amount was $260,288 under the 2008 Board Approved Total, and the resulting 15% Working Capital Allowance being $54,746 under the 2008 Board Approved Allowance.

2009 Actual $5,574,397 vs. 2008 Actual $5,216,059 – Variance $358,338:

2009 Total Eligible Distribution Expenses were higher than 2008 Actual by $134,245. The Operations Manager returned to work in January 2009 from LTD, accounting for part of this increase. The Eligible Distribution Expenses/OM&A Variance are explained in more detail in Exhibit 4.

2009 Actual Retail kWh's were lower than in 2008, but the increased rates for the Cost of Power resulted in an overall increased cost of $207,413.

In 2009, RSL added a new line truck (replacing a 20 year old unit that was brought into the RSL merger in 2000 with a $0.00 book value), and a new computer server to support the upgrade to our CIS/billing system in preparation for the move to Time of Use Rates.

These and other minor Capital Additions increased the Average Net Book Value by $307,090.

2010 Actual $6,250,814 vs. 2009 Actual $5,574,397 – Variance $676,417:

2010 Actual Retail kWh's were lower than in 2009, but the increased rates for Power Supply Expenses resulted in an overall increased cost of $153,095.

Effective December 31, 2010, RSL has added the Smart Meter Capital cost of $1,142,779 into our Gross Fixed Assets, and the accumulated depreciation expense of $118,841 into Accumulated Depreciation. The Smart Meter Project Capital is being rolled into our rate base as proposed by the Boards Guideline G-2011-0001 issued December 15, 2011. More detail is provided, for the Smart Meter Project, in Exhibit 11. Adding Smart Meter Capital into our Fixed Asset's, is the main reason for the $649,556 increase in 2010 Average Net Book Value, and the resulting Rate Base Increase of $676,417.

2011 Bridge $6,998,008 vs. 2010 Actual $6,250,814 – Variance $747,194:

2011 Bridge OM&A costs are higher than 2010 Actual by $164,327 due to an Operations Manager on staff for a full year, due to Smart Meter OM&A costs for 2011 of $87,856 being added into account 5065, and for added costs (account 5160- $40,788) due to the work for PCB elimination in our line transformers. Smart Meter OM&A costs are further explained in Exhibit 4.

Power Supply Expenses are forecast to be $9,835,045 compared to $9,131,849, because of higher rates, partially offset by reduced volumes of Retail kWh's. The commodity price of 0.06838 for RPP customers and 0.06561 for non RPP customers, used is from the Navigant Report on Regulated Price Plan issued Oct 18, 2010. This Price Report covers the period from November 1, 2010 until October 31, 2011.

2011 Fixed Assets increased for Capital Additions, and the 2011 Average Net Book Value has increased by $617,066, because the Smart Meter Capital is in our rate base for a full year, and because of the 2011 Capital Additions.

2012 Test $7,221,657 vs. 2011 Bridge $6,998,008 – and increased Variance of $223,649:

In 2012, Regulatory Expense has increase by $92,651, and OM&A has increased a net amount of $86,118. The 2012 Cost of Service Rate Application costs (Regulatory Expense) are forecast to be one hundred thousand higher than was included in our 2011 Regulatory Expense. Details for the Rate Application costs are included in Exhibit 4, Table 4.6.

Power Supply Expenses are forecast to be $10,499,095 compared to $9,835,045 because of higher rates, partially offset by reduced volumes of Retail kWh's in the Test Year. The commodity price of 0.07565 for RPP customers and 0.07191 for non RPP customers, used for 2012 is from the Navigant Regulated Price Plan Price Report issued October 17, 2011, covering the period from November 1, 2011 to October 31, 2012.

The resulting Working Capital Total increased by $781,675, and the Working Capital Allowance increase by $112,525 for the 2012 Test Year.

Fixed Asset additions in 2012 of $385,000, and the conversion to modified IFRS depreciation expense, result in an Average NBV increase of 111,123.

Table 2.2

Rate Base Continuity Statement and Variance Analysis

Description	2008 Board Approved	Actual 2008	Variance: 2008 Actual from 2008 OEB Approved	Actual 2009	Variance: 2009 Actual from 2008 Actual	Actual 2010	Variance: 2010 Actual from 2009 Actual	2011 Bridge MIFRS Format	Variance: 2011 Bridge from 2010 Actual	2012 Test MIFRS Format	Variance: 2012 Test from 2011 Bridge
Distribution Expenses - Operation	189,708	189,498	-210	232,774	43,277	178,302	-54,472	310,045	131,743	309,662	-383
Distribution Expenses - Maintenance	401,986	268,548	-133,438	292,592	24,045	346,408	53,816	401,700	55,292	411,374	9,674
Billing and Collecting	363,576	395,414	31,838	429,851	34,437	422,655	-7,195	422,000	-655	391,300	-30,700
Community Relations	254	486	232	9,220	8,734	450	-8,770	3,500	3,050	3,500	0
Administrative & General Expenses	631,102	629,125	-1,977	653,416	24,291	695,208	41,792	669,264	-25,944	775,892	106,628
Taxes Other than Income Taxes	22,426	21,292	-1,134	20,755	-538	21,558	804	22,400	842	23,300	900
Less: Capital Taxes within 6105	0	0	0	0	0	0	0	0	0	0	0
Total Eligible Distribution Expenses	1,609,052	1,504,363	-104,689	1,638,607	134,245	1,664,583	25,976	1,828,909	164,327	1,915,028	86,118
Power Supply Expenses											
Power Purchased	6,966,881	6,728,403	-238,478	7,132,007	403,604	7,174,199	42,192	7,727,381	553,182	8,370,389	643,008
Wholesale Market Services	770,074	620,540	-149,534	582,597	-37,943	484,015	-98,582	746,769	262,754	711,086	-35,683
Charges - NW	564748	592,958	28,210	540,602	-52,356	616,962	76,359	660,850	43,888	681,913	21,064
Charges - CN	525,187	539,938	14,751	483,115	-56,823	542,832	59,717	517,418	-25,414	554,698	37,280
Rural Rate Assistance	12,004	121,335	109,331	140,879	19,545	151,571	10,691	0	-151,571	0	0
Low Voltage Charges	192735	168,168	-24,567	99,554	-68,614	162,271	62,717	182,627	20,356	181,008	-1,620
Power Supply Expenses - Total	9,031,629	8,771,341	-260,288	8,978,754	207,413	9,131,849	153,095	9,835,045	703,196	10,499,095	664,050
				0	0	0	0	0	0	0	0
Working Capital Total	10,640,681	10,275,704	-364,977	10,617,362	341,658	10,796,432	179,070	11,663,954	867,523	12,414,122	750,168
				0	0	0	0	0	0	0	0
Working Capital Allowance @ 15%	1,596,102	1,541,356	-54,746	1,592,604	51,248	1,619,465	26,861	1,749,593	130,128	1,862,118	112,525
Fixed Assets											
Gross Fixed Assets	5,237,872	5,216,079	-21,793	5,759,089	543,010	7,170,977	1,411,888	7,591,516	420,539	7,976,516	385,000
Accumulated Depreciation	1,377,847	1,367,600	-10,247	1,643,983	276,383	2,023,384	379,401	2,242,278	218,894	2,606,677	364,399
Net Book Value	3,860,025	3,848,480	-11,545	4,115,106	266,626	5,147,593	1,032,487	5,349,238	201,645	5,369,839	20,601
Average Net book Value	3,678,402	3,674,703	-3,699	3,981,793	307,090	4,631,349	649,556	5,248,415	617,066	5,359,538	111,123
Rate Base	5,274,504	5,216,059	-58,445	5,574,397	358,338	6,250,814	676,417	6,998,008	747,194	7,221,657	223,649

3.0 MODIFIED IFRS

Transition to International Financial Reporting Standards:

The Canadian Accounting Standards Board ("AcSB") adopted a strategic plan that will have Canadian GAAP (CGAAP) converge with International Financial Reporting Standards (IFRS), effective January 1, 2012 and which will require entities to restate, for comparative purposes, their interim and annual financial statements and their opening financial position.

In October 2010, the AcSB approved the incorporation of IFRS into Part 1 of the Canadian Institute of Chartered Accountants ("CICA") Handbook for qualifying entities with activities subject to rate regulation. Part 1 of the CICA Handbook specifies that first-time adoption is mandatory for interim and annual financial statements relating to annual periods beginning on or after January 1, 2011. The AcSB decided to propose that qualifying entities with rate regulated activities be permitted, but not required, to continue applying the accounting standards in Part V of the CICA Handbook for an additional two years. This amendment also requires entities that do not prepare their interim and annual financial statements in accordance with Part 1 of the Handbook during the annual period beginning on or after January 1, 2011 to disclose that fact.

RSL deferred implementation of IFRS to January 1, 2012.

Transitional Analysis and Findings:

Overview:

Consultants were hired to assist with the transitional analysis, and completed the following:

- analysis regarding Fixed Assets Componentization, Useful Lives, and Overheads, was completed with the assistance of RSL staff, and in consultation with the External Auditors.

Standard: IAS 16 – Property, Plant and Equipment

Topic: Componentization and Depreciation

Objective: To document RSL's accounting policy on componentization and depreciation of property, plant and equipment.

Background: Each part of an item of property, plant and equipment (PP&E) with a cost that is significant in relation to the total cost of the item, shall be depreciated separately.

Using the Kinectrics Inc. Asset Amortization Study dated April 28, 2010, Report K-418022-RA-0001-R003, prepared for the Ontario Energy Board, RSL has adopted the Typical Useful Life (TUL) for fixed assets, as RSL has no better data on which to determine the TUL, and experience has shown that the TUL in the report is closer to the actual useful lives being experienced, than under CGAAP.

Depreciation is to be calculated on a systematic basis over the estimated useful life of the item after deducting its residual value when fully depreciated. In practice, the residual value of an asset is often insignificant and therefore immaterial in the calculation of the depreciable amount.

The residual value and the useful life of an asset shall be reviewed at least at each financial

year-end and, if expectations differ from previous estimates, the change(s) shall be accounted for as a change in an accounting estimate in accordance with IAS 8 Accounting Policies, Changes in Accounting Estimates and Errors.

Depreciation of an asset begins when it is available for use (i.e. when it is in the location and in the condition necessary for it to be capable of operating in the manner as intended).

Depreciation of an asset ceases, at the earlier of the date that the asset is classified as held for Sale, in accordance with IFRS 5, and the date that the asset is derecognized.

Considerations:

Significant components of PP&E will be separately accounted under IFRS. Each significant Component, and their estimated useful lives, for purposes of computing depreciation expense under IFRS, will be tracked in a sub account.

With the assistance of consultants, a detailed analysis of each “asset” type, the level of componentization required, and the useful life was conducted by RSL.

Table 2.3 below, show the conclusions from the work, and provides a comparison for PP&E’s useful life as it was assigned under CGAAP, and the revised TUL under MIFRS.

The Smart Meters Project Capital total of $1,294,090 is composed of three different Asset classes with three different TUL’s.

The three classes are:

Smart Meters, Collectors etc.,	amortized over 15 years -	$1,115,224,
Computers	Amortized over 5 years -	38,595
Software	Amortized over 5 years -	140,271
Total Capital		$1,294,090

The Smart Meter Models and further details are provided in Exhibit 11.

Table 2.3

Property Plant and Equipment Components and Estimated (TUL) Comparison

				MIFRS-Adj 2011 End Bal, 2012 Addn					
CCA Class	**OEB**	**Description**	**Exclude Fully Amort**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	Years CGAAP	TUL MIFRS
N/A	1610	Intangible Assets		0			0		
N/A	1805	Land		84,205			84,205	n/a	n/a
CEC	1806	Land Rights		0			0		
47	1808	Buildings and Fixtures		82,287	7,690		89,977	50	50
13	1810	Leasehold Improvements		0			0		
47	1820	1820 - Wholesale meters, normally incl below		326,992	15,000		341,992	25	25
47	1820	Distribution Station Equipment - Normally Primary belo		397,892	20,000		417,892	25	45
47	1860	Smart Meters		1,294,090			1,294,090	model	model
47	1830	Poles, Towers and Fixtures		502,092	72,310		574,402	25	45
47	1835	Overhead Conductors and Devices		1,839,430	50,000		1,889,430	25	60
47	1840	Underground Conduit		36,862			36,862	25	50
47	1845	Underground Conductors and Devices		797,248	20,000		817,248	25	40
47	1850	Line Transformers		1,031,223	60,000		1,091,223	25	45
47	1855	Services		281,637	20,000		301,637	25	60
47	1860	Meters		176,155	40,000		216,155	25	25
N/A	1865	Other Installations on Customer's Premises		0			0		
N/A	1905	Land		0			0		
CEC	1906	Land Rights		0			0		
47	1908	Buildings and Fixtures		0			0		
13	1910	Leasehold Improvements		8,796			8,796	10	10
8	1915	Office Furniture and Equipment		0			0		
10	1920	Computer Equipment - Hardware	(92,556)	163,688	20,000		183,688	5	5
12	1925	Computer Software	(11,546)	164,827	50,000		214,827	5	5
10	1930	Transportation Equipment		627,095			627,095	8	8
8	1935	Stores Equipment		0			0		
8	1940	Tools, Shop and Garage Equipment	(75,572)	137,984	10,000		147,984	10	10
8	1945	Measurement and Testing Equipment		0			0		
8	1950	Power Operated Equipment		0			0		
8	1955	Communication Equipment		0			0		
8	1960	Miscellaneous Equipment		0			0		
47	1990	Other Tangible Property		0			0		Average
47	1995	Contributions and Grants		(360,988)			(360,988)	25	45
	2005	Property under Capital Lease		0			0		
		Total before Work in Process	**(179,675)**	**7,591,516**	**385,000**	**0**	**7,976,516**		

The new levels of componentization and the corresponding useful lives will be applied beginning January 1, 2012.

2011 Rate Base has been restated as part of this Rate Application, in modified IFRS format as required by the Addendum to the Report of the Board (EB-2008-0408) issued June 13, 2011 on Implementing IFRS, Appendix A, Issue 2.

Standard: IAS 16 – Property, Plant and Equipment:

Topic: Capitalization - Overheads

Objective: To document the accounting policy on the capitalization of overheads.

Core Principle

The cost of an item of PP&E is recognized as an asset if and only if:

a) It is probable that future economic benefits will flow to the company; and
b) The cost of the item can be measured reliably.

The cost of an item of PP&E includes any costs that are directly attributable to bringing the asset to the location, and condition necessary for it to be capable of operating in the manner intended.

Certain costs are explicitly prohibited from inclusion as costs of an item of PP&E:

a) Costs of opening a new facility;
b) Costs of introducing a new product or service (including advertising and promotion);
c) Costs of conducting business in a new location or with a new class of customer (including costs of staff training)
d) Administration and other general overhead costs; and,
e) Day-to-day servicing costs.

IAS 16 does not indicate what constitutes an item of PP&E. Judgment is required when applying the core principle.

RSL's Observations and Conclusions:

Under IFRS the following costs will be capitalized:

Directly Attributable:

The cost must be directly attributed to a specific item of PP&E at the time it is incurred. The incurrence of that cost should aid directly in the construction effort making the asset more capable of being used than if the cost had not been incurred.

Payroll Burden:

Payroll allocation consists of the following benefits paid to or for employees: health benefits, WSIB, and the company portion of OMERS, CPP and EI. IAS 16 specifically allows for benefits as defined in IAS 19 to be included as a directly attributable cost. The payroll burden is allocated to capital based upon payroll dollars charged to capital.

Rolling Stock (Vehicle Burden):

The vehicle burden is allocated to capital based on the time that the vehicle is used on the job site, thus establishing the fact that the use of the vehicle is directly attributable to an item of PP&E.

Under IFRS the following costs will **not** be Capitalized:

- General and administrative overhead
- Day-to-day servicing costs - Day-to-day servicing costs are defined as costs of labour and consumables and may include the cost of small parts. The purpose of these expenditures is often described as for the "repairs and maintenance" of the item of PP&E.
- Under IFRS, training costs cannot be capitalized, but training on how to use a piece of equipment can be capitalized.

Amortization expense is an estimate of the deterioration of the vehicle. Amortization is not included in overhead, and is left as an administration expense.

Conclusion:

RSL has determined that there are a few minor changes required to our processing under MIFRS going forward, but any impact will be negligible, as our Capitalization process to date was mostly IFRS compliant.

For Depreciation, we need to track costs in sub accounts for componentization, because of different TUL and resulting differing depreciation rates.

4.0 STRANDED ASSETS

The forecast NBV of stranded assets, resulting from the Regulatory Smart Meter Project, have been removed from the Rate Base for 2012, and a separate rate rider has been requested to recover amount from Residential and GS < 50 kW customers.

Stranded Assets are the analog meters that were discarded as a result of the Smart Meter Project. The NBV of $180,441.57 was allocated between Residential and GS < 50 kW metered customers in the same ratio and the cost of the Smart Meters for these customer classes. The average Residential Smart Meter cost was $92.32 (68%), and the average GS < 50 kW Smart Meter cost was $252.40, or 38% of the total cost for the Smart Meters purchased.

Table 2.4 below, shows the allocation of the Stranded Assets, using these percentages, and the calculated monthly rate rider by customer class, required for RSL to recover these costs over a twelve month period, beginning May 1, 2012.

Stranded Assets had been included in account 1860, and RSL proposes to move these cost into a sub account of 1555, and apply the money received from the rate rider, against this sub account balance. RSL understands that no interest improvement is to be calculated on this balance. RSL has requested the rate rider to be for a one year period, starting May 1, 2012.

Table 2.4

Stranded Assets

Stranded Meter Costs	Total Capital	Less	Stranded
	GL 1860	Industrial	Meters
Capital Cost	$431,826.37	-$136,054.86	$295,771.51
Accumulated Depreciation	$156,841.02	-$41,511.08	$115,329.94
Net Book Value	$274,985.35	-$94,543.78	$180,441.57
	Residential	Commercial	Total
Number of Customers - 2012	5,016	770	5,786
Stranded Assets - %	68.0%	32.0%	100.0%
Straned Assets - $	$122,763.21	$57,678.36	$180,441.57
Stranded Meter Rate Rider (SMRR)	**$2.04**	**$6.24**	

GROSS ASSETS-PROPERTY, PLANT AND EQUIPMENT, ACCUMULATED DEPRECIATION

5.0 CONTINUITY STATEMENTS

Continuity Statements are shown in Table 2.5 to Table 2.11.

Tables 2.9 and 2.11 are for the 2011 and 2012 and presented in CGAAP for comparison.

In the Addendum to the Report of the Board (EB-2008-0408) on Implementing MIFRS, the Board authorized a generic deferral account to capture the differences relating to the Property, Plant and Equipment (PP&E) components of the rate base. This deferral account is to capture only the differences arising as a result of the accounting policy changes caused by the transition from CGAAP to MIFRS. Carrying charges are not approved for this account.

RSL last rebased in 2008, and is rebasing in 2012. RSL is moving to IFRS for financial reporting for 2012, and has restated 2011 in MIFRS format, because the prior year must be restated under IFRS.

2011 Fixed Asset Continuity Schedule for 2011 is shown in MIFRS in Table 2.8, and in CGAAP in table 2.9. 2012 Fixed Asset Continuity Schedule for 2012 is shown in MIFRS in Table 2.10, and in CGAAP in table 2.11. The deferral account variance caused by the 2011 restatement in MIFRS is $88,291 (CGAAP of $422,514 less MIFRS of $334,223).

RSL proposes to amortize this deferral account balance of $88,291 over the four year rebasing period, or a reduction of $22,073 in the depreciation expense for each year, starting in 2012. RSL’s rate of return is 6.1%, and the RRR to be added is ($22,073 x 6.1%) $1,346.

RSL’s 2012 depreciation expense under IFRS is $364,399, and is reduced to $340,980, as shown in Table 2.10.

Table 2.5

Fixed Asset Continuity Schedule as at December 31, 2008 (CGAAP)

CCA Class	OEB	Description	Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value
N/A	1610	Intangible Assets				0	0			0	0
N/A	1805	Land	84,205	0	0	84,205	0	0	0	0	84,205
CEC	1806	Land Rights				0				0	0
1	1808	Buildings and Fixtures	16,600	59,119	0	75,720	2,499	923	0	3,422	72,297
	1810	Leasehold Improvements				0				0	0
	1815	Transformer Station Equipment - Normally Primary above 50 kV				0				0	0
1	1820	Distribution Station Equipment - Normally Prima	546,819	115,522	0	662,340	104,543	24,183	0	128,726	533,614
	1825	Storage Battery Equipment				0				0	0
1	1830	Poles, Towers and Fixtures	290,928	79,565	0	370,493	37,298	13,228	0	50,527	319,966
1	1835	Overhead Conductors and Devices	1,646,735	42,081	0	1,688,815	423,289	66,711	0	490,000	1,198,815
1	1840	Underground Conduit	461,238	0	0	461,238	120,937	18,450	0	139,387	321,851
1	1845	Underground Conductors and Devices	311,876	28,871	0	340,747	65,786	13,052	0	78,838	261,909
1	1850	Line Transformers	797,580	106,912	0	904,492	163,537	34,041	0	197,578	706,914
1	1855	Services	154,098	56,990	0	211,087	18,035	7,304	0	25,339	185,749
1	1860	Meters	359,722	49,652	0	409,373	91,227	15,382	0	106,609	302,764
	1865	Other Installations on Customer's Premises				0				0	0
N/A	1905	Land				0				0	0
CEC	1906	Land Rights				0				0	0
1	1908	Buildings and Fixtures				0				0	0
	1910	Leasehold Improvements		8,796		8,796	0	440		440	8,357
8	1915	Office Furniture and Equipment				0				0	0
45	1920	Computer Equipment - Hardware	99,275	34,796	0	134,070	80,189	23,335	0	103,523	30,547
12	1925	Computer Software	17,425	63,785	0	81,210	9,790	9,863	0	19,654	61,556
10	1930	Transportation Equipment		22,126		22,126		2,766		2,766	19,361
10	1935	Stores Equipment				0				0	0
8	1940	Tools, Shop and Garage Equipment	111,752	10,817	0	122,569	60,183	11,716	0	71,899	50,670
	1945	Measurement and Testing Equipment				0				0	0
	1950	Power Operated Equipment				0				0	0
10	1955	Communication Equipment				0				0	0
	1960	Miscellaneous Equipment				0				0	0
	1970	Load Management Controls - Customer Premises				0				0	0
	1975	Load Management Controls - Utility Premises				0				0	0
	1980	System Supervisory Equipment				0				0	0
	1985	Sentinel Lighting Rentals				0				0	0
	1990	Other Tangible Property				0				0	0
1	1995	Contributions and Grants	(258,722)	(102,482)	0	(361,204)	(38,709)	(12,399)	0	(51,108)	(310,096)
	2005	Property under Capital Lease	0			0				0	0
		Total before Work in Process	**4,639,530**	**576,549**	**0**	**5,216,079**	**1,138,604**	**228,996**	**0**	**1,367,600**	**3,848,480**
WIP		Work in Process	51,601	(44,537)		7,064	0			0	7,064
		Total after Work in Process	**4,691,131**	**532,012**	**0**	**5,223,143**	**1,138,604**	**228,996**	**0**	**1,367,600**	**3,855,543**
							Less: Fully Allocated Depreci				
10	1935	Transportation					Transportation				
10	1955	Communication Equipment					Communication				
							Net Depreciatior	228,996			

Table 2.6

Fixed Asset Continuity Schedule as at December 1 31, 2009 (CGAAP)

CCA Class	OEB	Description	Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value
N/A	1610	Intangible Assets	0			0	0			0	0
N/A	1805	Land	84,205			84,205	0			0	84,205
CEC	1806	Land Rights	0			0	0			0	0
47	1808	Buildings and Fixtures	75,720	6,568		82,287	3,422	1,580		5,002	77,285
13	1810	Leasehold Improvements	0			0	0			0	0
47	1815	Transformer Station Equipment - Normally	0			0	0			0	0
47	1820	Distribution Station Equipment - Normally	662,340	1,121		663,461	128,726	26,516		155,242	508,219
47	1825	Storage Battery Equipment	0	0		0	0			0	0
47	1830	Poles, Towers and Fixtures	370,493	57,191		427,684	50,527	15,964		66,490	361,194
47	1835	Overhead Conductors and Devices	1,688,815	55,864		1,744,680	490,000	68,670		558,670	1,186,009
47	1840	Underground Conduit	461,238	2,588		463,826	139,387	18,495		157,882	305,944
47	1845	Underground Conductors and Devices	340,747	10,427		351,174	78,838	13,838		92,677	258,497
47	1850	Line Transformers	904,492	42,360		946,852	197,578	37,027	583	234,022	712,831
47	1855	Services	211,087	33,811		244,898	25,339	9,120		34,458	210,439
47	1860	Meters	409,373	3,485		412,858	106,609	16,445		123,054	289,804
N/A	1865	Other Installations on Customer's Premises	0			0	0			0	0
N/A	1905	Land	0			0	0			0	0
CEC	1906	Land Rights				0	0			0	0
47	1908	Buildings and Fixtures	0			0	0			0	0
13	1910	Leasehold Improvements	8,796			8,796	440	880		1,319	7,477
8	1915	Office Furniture and Equipment	0			0	0			0	0
10	1920	Computer Equipment - Hardware	134,070	18,112	800	151,383	103,523	28,785	800	131,509	19,874
12	1925	Computer Software	81,210	38,393		119,603	19,654	20,081		39,735	79,868
10	1930	Transportation Equipment	22,126	267,034		289,161	2,766	22,221		24,987	264,174
8	1935	Stores Equipment	0			0	0			0	0
8	1940	Tools, Shop and Garage Equipment	122,569	6,640		129,209	71,899	12,589		84,488	44,721
8	1945	Measurement and Testing Equipment	0			0	0			0	0
8	1950	Power Operated Equipment	0			0	0			0	0
8	1955	Communication Equipment	0			0	0			0	0
8	1960	Miscellaneous Equipment	0			0	0			0	0
47	1970	Load Management Controls - Customer Pr	0			0	0			0	0
47	1975	Load Management Controls - Utility Premis	0			0	0			0	0
47	1980	System Supervisory Equipment	0			0	0			0	0
47	1985	Sentinel Lighting Rentals	0			0	0			0	0
47	1990	Other Tangible Property	0			0	0			0	0
47	1995	Contributions and Grants	(361,204)	216		(360,988)	(51,108)	(14,444)		(65,551)	(295,436)
0	2005	Property under Capital Lease	0			0	0			0	0
		Total before Work in Process	**5,216,079**	**543,810**	**800**	**5,759,089**	**1,367,600**	**277,767**	**1,383**	**1,643,983**	**4,115,106**
WIP		Work in Process	7,064	(7,064)		0	0			0	0
		Total after Work in Process	**5,223,143**	**536,746**	**800**	**5,759,089**	**1,367,600**	**277,767**	**1,383**	**1,643,983**	**4,115,106**
							Less: Fully Allocated Dep				
	1925	Transportation					Transportation				
	1930	Stores Equipment					ommunication				
							t Depreciation	277,767			

Table 2.7

Fixed Asset Continuity Schedule as at 1 December 31, 2010 (CGAAP)

CCA Class	OEB	Description	Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value
N/A	1610	Intangible Assets	0			0	0			0	0
N/A	1805	Land	84,205			84,205	0			0	84,205
CEC	1806	Land Rights	0			0	0			0	0
47	1808	Buildings and Fixtures	82,287			82,287	5,002	1,646		6,648	75,639
13	1810	Leasehold Improvements	0			0	0			0	0
47	1815	Transformer Station Equipment - Nor	0			0	0			0	0
47	1820	Distribution Station Equipment - Norm	663,461	26,423		689,884	155,242	27,067		182,309	507,575
47	1860	Smart Meters	0	1,142,779		1,142,779	0	118,841		118,841	1,023,938
47	1830	Poles, Towers and Fixtures	427,684	24,408		452,092	66,490	17,596		84,086	368,006
47	1835	Overhead Conductors and Devices	1,744,680	49,751		1,794,430	558,670	70,782		629,452	1,164,978
47	1840	Underground Conduit	463,826	0		463,826	157,882	18,553		176,435	287,391
47	1845	Underground Conductors and Devices	351,174	9,110		360,284	92,677	14,229		106,906	253,378
47	1850	Line Transformers	946,852	44,371		991,223	234,022	38,762		272,783	718,440
47	1855	Services	244,898	16,739		261,637	34,458	10,131		44,589	217,048
47	1860	Meters	412,858	19,068		431,926	123,054	16,896		139,949	291,977
N/A	1865	Other Installations on Customer's Pre	0			0	0			0	0
N/A	1905	Land	0			0	0			0	0
CEC	1906	Land Rights	0			0	0	0		0	0
47	1908	Buildings and Fixtures	0			0	0			0	0
13	1910	Leasehold Improvements	8,796			8,796	1,319	880		2,199	6,597
8	1915	Office Furniture and Equipment	0			0	0			0	0
10	1920	Computer Equipment - Hardware	151,383	2,305		153,688	131,509	(19,005)		112,504	41,184
12	1925	Computer Software	119,603	35,224		154,827	39,735	22,859		62,594	92,233
10	1930	Transportation Equipment	289,161	37,935		327,095	24,987	41,496		66,483	260,613
8	1935	Stores Equipment	0			0	0			0	0
8	1940	Tools, Shop and Garage Equipment	129,209	3,775		132,984	84,488	13,110		97,597	35,386
8	1945	Measurement and Testing Equipmen	0			0	0			0	0
8	1950	Power Operated Equipment	0			0	0			0	0
8	1955	Communication Equipment	0			0	0			0	0
8	1960	Miscellaneous Equipment	0			0	0			0	0
47	1970	Load Management Controls - Custom	0			0	0			0	0
47	1975	Load Management Controls - Utility F	0			0	0			0	0
47	1980	System Supervisory Equipment	0			0	0			0	0
47	1985	Sentinel Lighting Rentals	0			0	0			0	0
47	1990	Other Tangible Property	0			0	0			0	0
47	1995	Contributions and Grants	(360,988)	0		(360,988)	(65,551)	(14,440)		(79,991)	(280,997)
	2005	Property under Capital Lease	0			0	0			0	0
		Total before Work in Process	**5,759,089**	**1,411,888**	**0**	**7,170,977**	**1,643,983**	**379,401**	**0**	**2,023,384**	**5,147,592**
WIP		Work in Process	0			0	0			0	0
		Total after Work in Process	**5,759,089**	**1,411,888**	**0**	**7,170,977**	**1,643,983**	**379,401**	**0**	**2,023,384**	**5,147,592**
							Less: Fully Allocated Dep				
	1925	Transportation					Transportation				
	1930	Stores Equipment					Communication				
							et Depreciation	379,401			

Table 2.8

Fixed Asset Continuity Schedule as 1 at December 31, 2011 (IFRS)

CCA Class	OEB	Description	Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value
N/A	1610	Intagible Assets	0			0	0	0		0	0
N/A	1805	Land	84,205			84,205	0	0		0	84,205
CEC	1806	Land Rights	0			0	0	0		0	0
47	1808	Buildings and Fixtures	82,287			82,287	6,648	1,646		8,294	73,994
13	1810	Leasehold Improvements	0			0	0	0		0	0
47	1815	Transformer Station Equipment - Normally Pri	0			0	0	0		0	0
47	1820	Distribution Station Equipment - Normally Prir	689,884	35,000		724,884	182,309	21,399		203,708	521,175
47	1860	Smart Meters	1,142,779	151,311		1,294,090	118,841	101,874		220,715	1,073,375
47	1830	Poles, Towers and Fixtures	452,092	50,000		502,092	84,086	10,602		94,688	407,404
47	1835	Overhead Conductors and Devices	1,794,430	45,000		1,839,430	629,452	30,282		659,734	1,179,696
47	1840	Underground Conduit	463,826		426,964	36,862	176,435	737	166,759	10,414	26,449
47	1845	Underground Conductors and Devices	360,284	10,000	(426,964)	797,248	106,906	19,806	(166,759)	293,470	503,778
47	1850	Line Transformers	991,223	40,000		1,031,223	272,783	22,472		295,255	735,968
47	1855	Services	261,637	20,000		281,637	44,589	4,527		49,116	232,521
47	1860	Meters	431,926	40,000	295,772	176,155	139,949	6,246	115,330	30,866	145,289
N/A	1865	Other Installations on Customer's Premises	0			0	0	0		0	0
N/A	1905	Land	0			0	0	0		0	0
CEC	1906	Land Rights	0			0	0	0		0	0
47	1908	Buildings and Fixtures	0			0	0	0		0	0
13	1910	Leasehold Improvements	8,796			8,796	2,199	880		3,079	5,718
8	1915	Office Furniture and Equipment	0			0	0	0		0	0
10	1920	Computer Equipment - Hardware	153,688	10,000		163,688	112,504	14,633		127,137	36,551
12	1925	Computer Software	154,827	10,000		164,827	62,594	29,656		92,250	72,577
10	1930	Transportation Equipment	327,095	300,000		627,095	66,483	63,937		130,420	496,676
8	1935	Stores Equipment	0			0	0	0		0	0
8	1940	Tools, Shop and Garage Equipment	132,984	5,000		137,984	97,597	13,548		111,146	26,838
8	1945	Measurement and Testing Equipment	0			0	0	0		0	0
8	1950	Power Operated Equipment	0			0	0	0		0	0
8	1955	Communication Equipment	0			0	0	0		0	0
8	1960	Miscellaneous Equipment	0			0	0	0		0	0
47	1970	Load Management Controls - Customer Prem	0			0	0	0		0	0
47	1975	Load Management Controls - Utility Premises	0			0	0	0		0	0
47	1980	System Supervisory Equipment	0			0	0	0		0	0
47	1985	Sentinel Lighting Rentals	0			0	0	0		0	0
47	1990	Other Tangible Property	0			0	0	0		0	0
47	1995	Contributions and Grants	(360,988)			(360,988)	(79,991)	(8,022)		(88,013)	(272,975)
	2005	Property under Capital Lease	0			0	0			0	0
		Total before Work in Process	**7,170,977**	**716,311**	**295,772**	**7,591,516**	**2,023,384**	**334,223**	**115,330**	**2,242,278**	**5,349,238**
WIP		Work in Process	0			0	0			0	0
		Total after Work in Process	**7,170,977**	**716,311**	**295,772**	**7,591,516**	**2,023,384**	**334,223**	**115,330**	**2,242,278**	**5,349,238**
							Less: Fully Allocated Dep				
	1925	Transportation					Transportation				
	1930	Stores Equipment					ommunication				
							et Depreciation	334,223			

Table 2.9

Fixed Asset Continuity Schedule as at December 1 31, 2011 (CGAAP)

Fixed Asset Continuity Schedule (Distribution & Ope											
As at December 31, 2011											
			Cost				Accumulated Depreciation				
CCA Class	OEB	Description	Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value
N/A	1610	Intagible Assets	0			0	0	0		0	0
N/A	1805	Land	84,205			84,205	0	0		0	84,205
CEC	1806	Land Rights	0			0	0	0		0	0
47	1808	Buildings and Fixtures	82,287			82,287	6,648	1,646		8,294	73,994
13	1810	Leasehold Improvements	0			0	0	0		0	0
47	1815	Transformer Station Equipment - Normally	0			0	0	0		0	0
47	1820	Distribution Station Equipment - Normally	689,884	35,000		724,884	182,309	28,295		210,604	514,280
47	1860	Smart Meters	1,142,779	151,311		1,294,090	118,841	101,874		220,715	1,073,375
47	1830	Poles, Towers and Fixtures	452,092	50,000		502,092	84,086	19,084		103,169	398,923
47	1835	Overhead Conductors and Devices	1,794,430	45,000		1,839,430	629,452	72,677		702,129	1,137,301
47	1840	Underground Conduit	463,826		426,964	36,862	176,435	1,474	166,759	11,151	25,712
47	1845	Underground Conductors and Devices	360,284	10,000	(426,964)	797,248	106,906	31,690	(166,759)	305,354	491,894
47	1850	Line Transformers	991,223	40,000		1,031,223	272,783	40,449		313,232	717,991
47	1855	Services	261,637	20,000		281,637	44,589	10,865		55,454	226,183
47	1860	Meters	431,926	40,000	295,772	176,155	139,949	6,246	115,330	30,866	145,289
N/A	1865	Other Installations on Customer's Premise	0			0	0	0		0	0
N/A	1905	Land	0			0	0	0		0	0
CEC	1906	Land Rights	0			0	0	0		0	0
47	1908	Buildings and Fixtures	0			0	0	0		0	0
13	1910	Leasehold Improvements	8,796			8,796	2,199	880		3,079	5,718
8	1915	Office Furniture and Equipment	0			0	0	0		0	0
10	1920	Computer Equipment - Hardware	153,688	10,000		163,688	112,504	14,633		127,137	36,551
12	1925	Computer Software	154,827	10,000		164,827	62,594	29,656		92,250	72,577
10	1930	Transportation Equipment	327,095	300,000		627,095	66,483	63,937		130,420	496,676
8	1935	Stores Equipment	0			0	0	0		0	0
8	1940	Tools, Shop and Garage Equipment	132,984	5,000		137,984	97,597	13,548		111,146	26,838
8	1945	Measurement and Testing Equipment	0			0	0	0		0	0
8	1950	Power Operated Equipment	0			0	0	0		0	0
8	1955	Communication Equipment	0			0	0	0		0	0
8	1960	Miscellaneous Equipment	0			0	0	0		0	0
47	1970	Load Management Controls - Customer Pr	0			0	0	0		0	0
47	1975	Load Management Controls - Utility Premi	0			0	0	0		0	0
47	1980	System Supervisory Equipment	0			0	0	0		0	0
47	1985	Sentinel Lighting Rentals	0			0	0	0		0	0
47	1990	Other Tangible Property	0			0	0	0		0	0
47	1995	Contributions and Grants	(360,988)			(360,988)	(79,991)	(14,440)		(94,430)	(266,557)
	2005	Property under Capital Lease	0			0	0			0	0
		Total before Work in Process	**7,170,977**	**716,311**	**295,772**	**7,591,516**	**2,023,384**	**422,514**	**115,330**	**2,330,569**	**5,260,947**
WIP		Work in Process	0			0	0			0	0
		Total after Work in Process	**7,170,977**	**716,311**	**295,772**	**7,591,516**	**2,023,384**	**422,514**	**115,330**	**2,330,569**	**5,260,947**
							Less: Fully Allocated Depr				
	1925	Transportation					Transportation				
	1930	Stores Equipment					Communicatior				
							Net Depreciatic	422,514			

Notes: 2011 amort adjusted for fully amortized assets, RSL startup asset error 426,964, stranded assets 295,772, 2011 deprn formula was not calc amort on 1/2 of 2010

Table 2.10

Fixed Asset Continuity Schedule as 1 at December 31, 2012 (IFRS)

CCA Class	OEB	Description	Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value
N/A	1610	Intangible Assets	0			0	0			0	0
N/A	1805	Land	84,205	-		84,205	0			0	84,205
CEC	1806	Land Rights	0	-		0	0			0	0
47	1808	Buildings and Fixtures	82,287	7,690		89,977	8,294	1,723		10,017	79,961
13	1810	Leasehold Improvements	0	-		0	0			0	0
47	1820	Wholesale Meters	326,992	15,000		341,992	64,899	13,380		78,279	263,713
47	1820	Distribution Station Equipment - Normally Pri	397,892	20,000		417,892	138,810	9,064		147,874	270,018
47	1860	Smart Meters	1,294,090	-		1,294,090	220,715	110,121		330,836	963,253
47	1830	Poles, Towers and Fixtures	502,092	72,310		574,402	94,688	11,961		106,649	467,753
47	1835	Overhead Conductors and Devices	1,839,430	50,000		1,889,430	659,734	31,074		690,808	1,198,622
47	1840	Underground Conduit	36,862	-		36,862	10,414	737		11,151	25,712
47	1845	Underground Conductors and Devices	797,248	20,000		817,248	293,470	20,181		313,651	503,597
47	1850	Line Transformers	1,031,223	60,000		1,091,223	295,255	23,583		318,838	772,385
47	1855	Services	281,637	20,000		301,637	49,116	4,861		53,977	247,660
47	1860	Meters	176,155	40,000		216,155	30,866	7,846		38,712	177,443
N/A	1865	Other Installations on Customer's Premises	0	-		0	0			0	0
N/A	1905	Land	0	-		0	0			0	0
CEC	1906	Land Rights	0	-		0	0			0	0
47	1908	Buildings and Fixtures	0	-		0	0			0	0
13	1910	Leasehold Improvements	8,796	-		8,796	3,079	880		3,959	4,838
8	1915	Office Furniture and Equipment	0	-		0	0			0	0
10	1920	Computer Equipment - Hardware	163,688	20,000		183,688	127,137	16,226		143,363	40,325
12	1925	Computer Software	164,827	50,000		214,827	92,250	35,656		127,906	86,921
10	1930	Transportation Equipment	627,095	-		627,095	130,420	78,387		208,807	418,289
8	1935	Stores Equipment	0	-		0	0	-		0	0
8	1940	Tools, Shop and Garage Equipment	137,984	10,000		147,984	111,146	6,741		117,887	30,097
8	1945	Measurement and Testing Equipment	0	-		0	0	-		0	0
8	1950	Power Operated Equipment	0	-		0	0	-		0	0
8	1955	Communication Equipment	0	-		0	0	-		0	0
8	1960	Miscellaneous Equipment	0	-		0	0	-		0	0
47	1970	Load Management Controls - Customer Prem	0	-		0	0	-		0	0
47	1975	Load Management Controls - Utility Premises	0	-		0	0	-		0	0
47	1980	System Supervisory Equipment	0	-		0	0	-		0	0
47	1985	Sentinel Lighting Rentals	0	-		0	0	-		0	0
47	1990	Other Tangible Property	0	-		0	0	-		0	0
47	1995	Contributions and Grants	(360,988)	-		(360,988)	(88,013)	- 8,022		(96,035)	(264,953)
	2005	Property under Capital Lease	0	-		0	0			0	0
		Total before Work in Process	**7,591,516**	**385,000**	**0**	**7,976,516**	**2,242,278**	**364,399**	**0**	**2,606,677**	**5,369,839**
WIP		Work in Process	0			0	0			0	0
		Total after Work in Process	**7,591,516**	**385,000**	**0**	**7,976,516**	**2,242,278**	**364,399**	**0**	**2,606,677**	**5,369,839**
				Amort per CGAAP		435,805	Rate Base Adjustment				
	1925	Transportation		Amort per MIFRS		340,980	1/4 of 2011	22,073			
	1930	Stores Equipment		Reduction:		94,825	RRR 6.1%	1,346			
							Net Deprecia	340,980			

Table 2.11

Fixed Asset Continuity Schedule as at December 1 31, 2012 (CGAAP)

Fixed Asset Continuity Schedule (Distribution & Operati											
As at December 31, 2012			CGAAP Comparison								
			Cost				Accumulated Depreciation				
CCA Class	OEB	Description	Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value
N/A	1610	Intangible Assets	0			0	0			0	0
N/A	1805	Land	84,205	-		84,205	0			0	84,205
CEC	1806	Land Rights	0	-		0	0			0	0
47	1808	Buildings and Fixtures	82,287	7,690		89,977	8,294	1,723		10,017	79,961
13	1810	Leasehold Improvements	0	-		0	0			0	0
47	1820	Wholesale Meters	326,992	15,000		341,992	64,899	13,380		78,279	263,713
47	1820	Distribution Station Equipment - Normally Pri	397,892	20,000		417,892	138,810	16,316		155,126	262,766
47	1860	Smart Meters	1,294,090	-		1,294,090	220,715	110,121		330,836	963,253
47	1830	Poles, Towers and Fixtures	502,092	72,310		574,402	103,169	21,530		124,699	449,703
47	1835	Overhead Conductors and Devices	1,839,430	50,000		1,889,430	702,129	74,577		776,706	1,112,724
47	1840	Underground Conduit	36,862	-		36,862	11,151	1,474		12,625	24,238
47	1845	Underground Conductors and Devices	797,248	20,000		817,248	305,354	32,290		337,644	479,604
47	1850	Line Transformers	1,031,223	60,000		1,091,223	313,232	42,449		355,681	735,542
47	1855	Services	281,637	20,000		301,637	55,454	11,665		67,119	234,518
47	1860	Meters	176,155	40,000		216,155	30,866	7,846		38,712	177,443
N/A	1865	Other Installations on Customer's Premises	0	-		0	0			0	0
N/A	1905	Land	0	-		0	0			0	0
CEC	1906	Land Rights	0	-		0	0			0	0
47	1908	Buildings and Fixtures	0	-		0	0			0	0
13	1910	Leasehold Improvements	8,796	-		8,796	3,079	880		3,959	4,838
8	1915	Office Furniture and Equipment	0	-		0	0			0	0
10	1920	Computer Equipment - Hardware	163,688	20,000		183,688	127,137	16,226		143,363	40,325
12	1925	Computer Software	164,827	50,000		214,827	92,250	35,656		127,906	86,921
10	1930	Transportation Equipment	627,095	-		627,095	130,420	78,387		208,807	418,289
8	1935	Stores Equipment	0	-		0	0	-		0	0
8	1940	Tools, Shop and Garage Equipment	137,984	10,000		147,984	111,146	6,741		117,887	30,097
8	1945	Measurement and Testing Equipment	0	-		0	0	-		0	0
8	1950	Power Operated Equipment	0	-		0	0	-		0	0
8	1955	Communication Equipment	0	-		0	0	-		0	0
8	1960	Miscellaneous Equipment	0	-		0	0	-		0	0
47	1970	Load Management Controls - Customer Prem	0	-		0	0	-		0	0
47	1975	Load Management Controls - Utility Premises	0	-		0	0	-		0	0
47	1980	System Supervisory Equipment	0	-		0	0	-		0	0
47	1985	Sentinel Lighting Rentals	0	-		0	0	-		0	0
47	1990	Other Tangible Property	0	-		0	0	-		0	0
47	1995	Contributions and Grants	(360,988)	-		(360,988)	(94,430)	- 14,440		(108,870)	(252,117)
	2005	Property under Capital Lease	0	-		0	0			0	0
		Total before Work in Process	**7,591,516**	**385,000**	**0**	**7,976,516**	**2,323,673**	**456,821**	**0**	**2,780,494**	**5,196,022**
WIP		Work in Process	0			0	0			0	0
		Total after Work in Process	**7,591,516**	**385,000**	**0**	**7,976,516**	**2,323,673**	**456,821**	**0**	**2,780,494**	**5,196,022**

1925	Transportation	
1930	Stores Equipment	

Less: Fully Allocated De	
Transportatic	
Communicat	
Net Deprecia	456,821

6.0 GROSS ASSETS TABLE

Gross Assets – Property Plant and Equipment:

RSL owns and operates the electricity distribution system in the Township of South Dundas, the Township of Edwardsburgh/Cardinal, The Town of Prescott, and the Village of Westport. RSL does not provide electricity distribution services to all of the municipal boundaries for Township of South Dundas, the Township of Edwardsburgh/Cardinal, but rather only for the former Villages Williamsburg, Morrisburg, Iroquois, and Village of Cardinal.

Table 2.12 shows our year-over-year Capital Additions from the 2008 Board Approved, up to and including, the 2012 Test year.

Capital additions were made to meet Regulatory Requirements, to meet customer expectations, to maintain service reliability, for safety, and for customer driven investments.

Capital Expenditures in this table have excluded the Regulatory Required Smart Meter Capital Project for easier comparison purposes. The Smart Meter project is dealt with in more detail in Exhibit 11.

Table 2.12

Capital Expenditures Comparison

CCA	OEB	Description	2008 Board Approved	2008 Actual	2009 Actual	2010 Actual	2011 Bridge	2012 Test
N/A	1805	Land						
CEC	1806	Land Rights	$40,000	$59,119	$6,568			$7,690
47	1808	Buildings and Fixtures						
47	1820	Wholesale Meters						$15,000
47	1820	Distribution Station Equipment - < 50 kV	$62,400	$115,522	$1,121	$26,423	$35,000	$20,000
47	1860	Smart Meters						
47	1830	Poles, Towers and Fixtures	$45,000	$79,565	$57,191	$24,408	$50,000	$72,310
47	1835	Overhead Conductors and Devices	$45,000	$42,081	$55,864	$49,750	$45,000	$50,000
47	1840	Underground Conduit			$2,588			
47	1845	Underground Conductors and Devices		$28,871	$10,427	$9,110	$10,000	$20,000
47	1850	Line Transformers	$20,000	$106,912	$42,360	$44,371	$40,000	$60,000
47	1855	Services		$56,990	$33,811	$16,739	$20,000	$20,000
47	1860	Meters	$35,000	$49,652	$3,485	$19,068	$40,000	$40,000
47	1908	Buildings and Fixtures						
13	1910	Leasehold Improvements		$8,796				
8	1915	Office Furniture and Equipment						
10	1920	Computer Equipment - Hardware	$35,000	$34,796	$18,112	$2,305	$10,000	$20,000
12	1925	Computer Software	$60,000	$63,785	$38,393	$35,224	$10,000	$50,000
10	1930	Transportation Equipment	$250,000	$22,126	$267,034	$37,935	$300,000	
8	1935	Stores Equipment						
8	1940	Tools, Shop and Garage Equipment	$10,000	$10,817	$6,640	$3,775	$5,000	$10,000
47	1995	Contributions and Grants		-$102,482	$216			
		Total Capital Expenditures	$602,400	$576,550	$543,810	$269,108	$565,000	$385,000

7.0 VARIANCE ANALYSIS ON GROSS ASSETS

Gross Asset Variance analysis for those over the materiality limit, and listed in Table 2.13 is explained below:

2008 Board Approved vs. 2008 Actual:

1820 Sub Stations and Wholesale Meter points:

- 2008 Board approved of $617,430 Vs. Actual of $662,340 – Variance of $44,910. An Industrial customer upgrade was completed in the fall of 2008. The customer added their own transformer station, and RSL was required to have a new feeder line installed, crossing the railway tracks.

1830 Poles Tower and Fixtures

- 2008 Board Approved 323,028 vs. 2008 actual of $370,493 – Variance of $47,465. An unexpected customer was added to our system in 2008, which required us to install a new line of 15 poles. There is an offset in contributed capital of $11,643 for the (bio-digester) project.

1850 Line Transformers

- 2008 Board Approved of $806,150 vs. 2008 Actual of $904,492 – Variance of $98,342. The price of transformers continued to increase dramatically, and the increased lead time to acquire replacements required RSL to add additional spares. As well there were several unexpected customer driven Capital Projects that required additional transformer purchases. There is an offset in contributed capital of $61,561 for these transformers.

1855 Services

- 2008 Board Approved of $140,825 vs. 2008 Actual of $211,087 – Variance of $70,262. A number of old services were replaced to maintain service reliability and customer service. In addition, the new commercial and Industrial customers added to our system, increased this cost over Board approved, and an offset of $1,063 is included in 1995 contributed Capital.

1930 Rolling Stock

- 2008 Board Approved of $250,000 vs. 2008 actual of $22,126 – Variance of ($227,874). The new line truck expected for delivery in 2008, was delivered in 2009. RSL purchased a new light truck, which replaced a 1994 ½ ton truck.

1995 Contributed Capital

- 2008 Board Approved of ($261,333) vs. 2008 Actual of ($361,204) – Variance $99,871. Contributed Capital from unexpected projects account for this increase

– a 16 unit housing complex in Williamsburg, the Iroquois Bio-digester line, and the sewage plant in Morrisburg. Amounts vary from year to year and ar difficult to forecast, because they are usually from customer driven requirements that RSL has no advance knowledge of.

2009 Actual vs. 2008 Actual:

1830 Poles Tower and Fixtures

- 2009 Actual of 427,684 vs. 2008 Actual of 370,493 – Variance $57,191. Costs for our pole replacement program which commenced in 2008, and is ongoing.

1835 Overhead Conductors and Devices – Variance $55,865.

- 2009 Actual of $1,744,680 Vs. 2008 Actual of $1,688,815. Lines were replaced as poles were replaced, under the pole replacement program.

1930 Rolling Stock

- 2009 Actual of $289,161 vs. 2008 Actual of $22,126. A line truck planned to be delivered in 2008, was delivered in 2009.

2010 Actual vs. 2009 Actual:

1860 Smart Meters

- Smart Meter actual Capital Cost of $1,142,779 for the project, to the end of 2010, were added to the Fixed Asset Continuity Schedule for 2010 in cell E17 of the Revenue Requirement Model. The details by Asset type (Meters, Computers, and Software) are provided in the Smart Meter Model V2.17. We added the December 31, 2010 Capital costs to date as one number in Cell E17 on the Continuity, and in the Gross Fixed Asset Schedules of the Revenue Requirements Model, for a clearer audit trail. The depreciation expense used in the Continuity Schedule was also calculated in the Smart meter Model 2.17. More details for the Project total are also shown in Exhibit 11 in Table 15.1.

2011 Bridge Year vs. 2010 Actual:

1860 Smart Meters - $151,311

- Additional Smart Capital costs for 2011 of $151,311 were added into the models, as part of the process to get the Smart Meter costs into our rate base. Included in this application is an interim external audit conducted on our 2011 YTD August 2011 Capital and OM&A costs. A copy of the interim external audit is attached to Exhibit 9.

1830 Poles Towers & Fixtures - $50,000

- In 2011 under our pole replacement program, several back yard poles and lines were replaced in South Dundas.

1835 Distribution Lines & Feeders – see comments above for the poles, for the $45,000 increase in 2011.

1840 Underground Conduit & 1845 Underground Conductors and Devices:

- During review of our historical records, in preparation for MIFRS, an error was discovered in the recording of Fixed Asset costs at the time of RSL's Incorporation in 2000. $426,964 of NBV costs added to RSL from the four former PUC's was incorrectly classified as 1840 Underground Conduit, when it should have been classified as 1845 Underground conductors and Devices. Accounting entries were made in 2011 to correctly classify those costs. The net effect is zero dollar impact, as both fixed asset accounts were depreciated at the same rate under CGAAP. To correct the records, and to apply the correct TUL going forward, we have moved the assets and the accumulated depreciation to the correct accounts effective January 1, 2011. For the rate base average calculation, and for amortization, we have treated this transfer as if it happened December 31, 2010.

1860 Meters

- Stranded Meter Assets of Capital cost of $295,772, less accumulated depreciation of $115,330 (NBV) were removed from our rate base effective December 31, 2011, a Rate Rider was requested to recover the stranded asset NBV of $180,442, for the Residential and Commercial meters, replaced by the Smart meters, before the end of their useful life. This cost has been removed from our rate base, and added to a sub-account "Stranded Meter costs" of account 1555. Associated recoveries from the rate rider will be recorded in this sub-account to reduce the balance. RSL has completed 100% of its smart meter deployment.

1930 Line Trucks

- The last old (22 years) line truck was replaced in 2011. The old Mack Line Trucks condition, required it to be replaced. The Mack had no NBV when brought into RSL at RSL's Incorporation, so there was no value to remove for the disposal. The result is an increase of approximately $300,000 in Capital account 1930.

2012 Test Year vs. 2011 Bridge Year:

1820 Distribution Station Equipment and Wholesale Meters

- For MIFRS Distribution Station Equipment is assign a TUL of 45 years, and Wholesale Meters are assigned a TUL of 25 years. For the models we performed an amortization calculation for 2011 & 2012 under MIFRS using the above rates. For 2012 we separated the dollar value, reducing 1820 by $326,992 and adding this amount into the line for the OEB account 1815. The accumulated depreciation of $145,706 for the wholesale meters was also moved.

1830 Pole Replacement Program

- Planned replacements in 2012 of $72,310. A number of poles in our service area are nearing the end of their useful life and are required to be replaced on an on-going basis.

1835 Distribution Lines & Feeders

- Planned line replacements for 2012 - $50,000. RSL has a small amount of undersized conductors that are scheduled for replacement for safety reasons.

1860 Transformers

- Spare transformers to be purchased - $60,000. These transformers, are for replacement of stock, and for units that will be replaced as part of the PCB elimination project – to be carried out over four to five years.

1925 Computer Software

- RSL's purchase order, Work order and Inventory system from 1996, is no longer supported, and needs to be replaced.

Table 2.13

Gross Fixed Asset Variance

Acct	Description	2008 Board Approved	2,008 Actual	Variance 2008 Actual vs. 2008 OEB	2,009 Actual	Variance 2009 Actual vs. 2008 Actual	2,010 Actual	Variance 2010 Actual vs. 2009 Actual	2,011 Actual	Variance 2011 Bridge vs. 2010 Actual	2,012 Actual	Variance 2012 Test vs. 2011 Bridge
1,805	Land	$84,205	$84,205	$0	$84,205	$0	$84,205	$0	$84,205	$0	$84,205	$0
1,808	Building	$56,600	$75,719	$19,119	$82,287	$6,568	$82,287	$0	$82,287	$0	$89,977	$7,690
1,815	Wholesale meters to1820	$0	$0	$0	$0	$0	$0	$0	$0	$0	$341,992	$341,992
1,820	Dist.Stn.Equipment	$617,430	$662,340	$44,910	$663,461	$1,121	$689,884	$26,423	$724,884	$35,000	$417,892	-$306,992
1,860			$0	$0	$0	$0	$1,142,779	$1,142,779	$1,294,090	$151,311	$1,294,090	$0
1,830	Poles,Towers & Fixtures	$323,028	$370,493	$47,465	$427,684	$57,191	$452,092	$24,408	$502,092	$50,000	$574,402	$72,310
1,835	Dist.Lines&Feeders	$1,700,734	$1,688,815	-$11,919	$1,744,680	$55,864	$1,794,430	$49,751	$1,839,430	$45,000	$1,889,430	$50,000
1,840	Distribution-Underground	$460,764	$461,238	$474	$463,826	$2,588	$463,826	$0	$36,863	-$426,963	$36,863	$0
1,845	Undrgrd Conductors & Device	$315,954	$340,747	$24,793	$351,174	$10,427	$360,284	$9,110	$797,248	$436,964	$817,248	$20,000
1,850	Line Transformers	$806,150	$904,492	$98,342	$946,852	$42,360	$991,223	$44,371	$1,031,223	$40,000	$1,091,223	$60,000
1,855	Services	$140,825	$211,087	$70,262	$244,898	$33,811	$261,637	$16,739	$281,637	$20,000	$301,637	$20,000
1,860	Meters	$400,940	$409,373	$8,433	$412,858	$3,485	$431,926	$19,068	$176,155	-$255,772	$216,155	$40,000
1,910	Leasehold Improvements	$0	$8,796	$8,796	$8,796	$0	$8,796	$0	$8,796	$0	$8,796	$0
1,915	Office Furniture & Equipment	$5,000				$0		$0		$0		$0
1,920	Computer Equipment	$137,556	$134,070	-$3,486	$151,383	$17,312	$153,688	$2,305	$163,688	$10,000	$183,688	$20,000
1,925	Computer Software	$71,546	$81,210	$9,664	$119,603	$38,393	$154,827	$35,224	$164,827	$10,000	$214,827	$50,000
1,930	Line Trucks & trailers	$250,000	$22,126	-$227,874	$289,161	$267,034	$327,095	$37,935	$627,095	$300,000	$627,095	$0
1,940	Misc Equip Major Tools	$128,453	$122,569	-$5,884	$129,209	$6,640	$132,984	$3,775	$137,984	$5,000	$147,984	$10,000
1,995	Contribution to Capital	-$261,333	-$361,204	-$99,871	-$360,988	$216	-$360,988	$0	-$360,988	$0	-$360,988	$0
		$5,237,852	$5,216,079	-$16,773	$5,759,088	$543,010	$7,170,976	$1,411,888	$7,591,516	$420,540	$7,976,516	$385,000

8.0 ACCUMULATED DEPRECIATION TABLE

RSL uses the straight line method of amortization to determine the depreciation expense for pooled distribution assets, and on identifiable assets, individually. The half year rule is followed, in that RSL takes a half year of depreciation in the year of acquisition, and a half year in the year of disposal. A full year's amortization is calculated on a straight line basis over estimated useful life of the asset.

RSL has followed the amortization schedule provided at Schedule B of the OEB's 2007 Electricity Distribution Rate Handbook until the end of 2010.

For 2011 and 2012, RSL has used the TUL from the Kinectrics depreciation study, and applied those depreciation rates as a full year rate for 2011 and 2012.

Variance Analysis on Accumulated Depreciation:

Changes in accumulated depreciation are directly affected by changes in fixed assets due to the addition of new investment in assets, the removal of fully depreciated assets from the grouped asset classes, the disposition of identifiable assets, and by the transition to IFRS for 2012, with a restatement of 2011 in IFRS rates, for comparison purposes.

In addition, at the end of 2011, RSL has removed stranded assets of $295,772 and accumulated depreciation of $115,330 from account 1860 and using the Smart Meter models, requested a rate rider of $2.04 per month per Residential customer, and $6.24 per GS <50 kW metered account to recover this cost. The net book value of stranded assets of $180,442 has been removed from our rate base for 2012.

Smart Meter Capital costs of $1,294,090 to the end of 2011, have been added to the rate base, increasing depreciation expense.

An analysis of capital expenditures and rate base has already been provided in this Exhibit.

The capital expenditures and rate base changes drive all changes/variances.

The Accumulated Depreciation Variance, shown below in Table 2.14, does not include the adjustment of $22,073 or the Regulated Rate of Return of 6.1% on this ($1,346), which is the required Rate Base Adjustment as a result of restating 2011 accumulated depreciation in MIFRS format.

Table 2.14

Accumulated Depreciation

Acct	Description	2008 Board Approved	2,008 Actual	Variance 2008 Actual vs. 2008 OEB	2,009 Actual	Variance 2009 Actual vs. 2008 Actual	2,010 Actual	Variance 2010 Actual vs. 2009 Actual	2,011 Actual	Variance 2011 Bridge vs. 2010 Actual	2,012 Actual	Variance 2012 Test vs. 2011 Bridge
1,805	Land											
1,808	Building	$5,231	$3,422	-$1,809	$5,002	$1,580	$6,648	$1,646	$8,294	$1,646	$10,017	$1,723
1,815	Wholesale meters to1820	$0	$0	$0	$0	$0	$0	$0	$0	$0	$78,279	$78,279
1,820	Dist.Stn.Equipment	$128,156	$128,726	$570	$155,242	$26,516	$182,309	$27,067	$203,708	$21,399	$147,874	-$55,835
1,860	Smart Meters		$0	$0	$0	$0	$118,841	$118,841	$220,715	$101,874	$330,836	$110,121
1,830	Poles,Towers & Fixtures	$49,061	$50,527	$1,466	$66,490	$15,964	$84,086	$17,596	$94,688	$10,602	$106,649	$11,961
1,835	Dist.Lines&Feeders	$490,599	$490,000	-$599	$558,670	$68,670	$629,452	$70,782	$659,734	$30,282	$690,808	$31,074
1,840	Distribution-Underground	$139,360	$139,387	$27	$157,882	$18,495	$176,435	$18,553	$10,414	-$166,022	$11,151	$737
1,845	Undrgrd Conductors & Device	$78,506	$78,838	$332	$92,677	$13,838	$106,906	$14,229	$293,470	$186,565	$313,651	$20,181
1,850	Line Transformers	$195,074	$197,578	$2,504	$234,022	$36,444	$272,783	$38,762	$295,255	$22,472	$318,838	$23,583
1,855	Services	$23,402	$25,339	$1,937	$34,458	$9,120	$44,589	$10,131	$49,116	$4,527	$53,977	$4,861
1,860	Meters	$107,889	$106,609	-$1,280	$123,054	$16,445	$139,949	$16,896	$30,866	-$109,084	$38,712	$7,846
1,910	Leasehold Improvements	$0	$440	$440	$1,319	$880	$2,199	$880	$3,079	$880	$3,959	$880
1,915	Office Furniture & Equipment	$750	$0			$0		$0		$0		$0
1,920	Computer Equipment	$104,528	$103,523	-$1,005	$131,509	$27,985	$112,504	-$19,005	$127,137	$14,633	$143,363	$16,226
1,925	Computer Software	$17,512	$19,654	$2,142	$39,735	$20,081	$62,594	$22,859	$92,250	$29,656	$127,906	$35,656
1,930	Line Trucks & trailers	$43,750	$2,766	-$40,984	$24,987	$22,221	$66,483	$41,496	$130,420	$63,937	$208,807	$78,387
1,940	Misc Equip Major Tools	$72,863	$71,899	-$964	$84,488	$12,589	$97,597	$13,110	$111,146	$13,548	$117,887	$6,741
1,995	Contribution to Capital	-$49,110	-$51,108	-$1,998	-$65,551	-$14,444	-$79,991	-$14,440	-$88,013	-$8,022	-$96,035	-$8,022
		$1,407,571	$1,367,600	-$39,221	$1,643,983	$276,384	$2,023,384	$379,401	$2,242,278	$218,893	$2,606,677	$364,399

9.0 CAPITAL BUDGET

Introduction:

Rideau St. Lawrence Distribution is responsible for design, construction, operation and maintenance of the electric distribution system within RSL's service territory.

Capital Budgeting

The annual budget process is an integral planning tool, and attempts to ensures that appropriate resources are available, to maintain and grow its capital infrastructure. The focus of capital expenditures has been for expansion to connect new customers, for regulatory compliance, or for reinforcing our existing system. The benefits that result from these expenditures include adequacy, reliability, and quality of service to our customers.

Over the last few years, Regulatory Compliance has been the major driver of the budget process and for capital expenditures.

The management team prepares, review, and present the budget, including Capital Expenditures, to the Board of Directors for final review and approval.

The Board of Directors process includes a quarterly review of our results, and Capital Expenditures are part of that review.

RSL's Capital Budget process is based on:

- Regulatory compliance (Smart Meters, PCB elimination, IESO Wholesale Meters).

  These projects are capital investments which are being driven by the regulatory requirements. These requirements may include, among others, directions from the Board, the IESO, the Ministry of Energy (& Infrastructure) or the Ministry of Environment.

  In 2006, The Government of Ontario established targets for the installation of 800,000 smart electricity meters by December 31, 2008 and installation of smart meters for all Ontario customers by December 31, 2011. As a named distributor in the London Hydro RFP, on June 28, 2009 the government authorized RSL via Regulation 427/06 to proceed with "metering 1 activities pursuant to the Request for Proposal (RFP) for Advanced Metering Infrastructure (AMI) – Phase I Smart Meter Deployment issued August 14, 2007 by London Hydro Inc." RSL has completed its Smart Meter installations.

- Customer Demand
  These are projects that RSL undertakes to meet customer obligations in accordance with the Board's Distribution System Code (the "DSC") and RSL's Conditions of Service. Activities include connecting new residential and general service customers, constructing distribution plant to connect new subdivisions and relocating system plant equipment for roadway reconstruction work.

- Renewal of aging infrastructure
  Replacement projects are completed when it has been determined, through proper condition assessment, that assets have reached the end of their useful life. RSL completes inspections of its plant and performs predictive testing on certain assets where such testing is available, and replaces assets based on inspection and testing results as warranted. In some cases the projects involve spot replacement of assets; in other cases, the projects involve complete asset replacement within a geographic area.

- System capacity increases and efficiency improvements
  RSL is not in a growth situation, so most of the work in this area is for improvements to the system, or for new customer connections. Projects can take the form of new or upgraded feeders and or transformers.

- Transformer Distribution Stations
  Transformer Stations are used to transfer power from the transmission system at 44 kV to the distribution system. Investments are undertaken to improve or maintain reliability to a large numbers of customers, maintain security and safety at the station, and to meet long range load. The Station facilities include power transformers, circuit breakers, switchgear, bus, insulators, power cables, support structures, disconnect switches and ancillary equipment.

- Customer Connections and Metering
  Capital expenditures include meter installations, meter upgrades, and the capital components of wholesale and retail meter verification activities. As of December 31, 2011, RSL will have completed 100% of the deployment of Smart Meters as approved by Ontario Regulation 427/06. Smart Meter capital is currently recorded in the smart meter variance account 1555.

- Other Items
  This includes computer equipment, software, general plant, and tools.

Capital Budget by Project – Materiality Analysis:

Capital Budget by Project – 2008:

Project Description:	Erection of a Butler Building.
Need:	Require a more secure storage for transformers and wire.
Scope:	Metal Building erected on owned property beside our sub-station
Capital costs:	$59,119
Construction date:	Started and completed in 2008.
Project Description:	Wholesale Meters in Iroquois and in Cardinal MS2.
Need:	Must be upgraded to IESO Market Rules.
Scope:	Meter points purchased from Hydro One, upgraded by a contractor.
Capital costs:	$60,999
Construction date:	Started and completed in October of 2008.

Project Description:	Northern Cables
Need:	Provide service upgrade to a customer.
Scope:	Extend distribution system from a new feeder off the 44 kW.
Capital costs:	$47,840
Construction date:	Started October 2008, energized December 12, 2008.

Project Description:	Bio-Digester
Need:	New customer – provide service.
Scope:	Extend distribution system – system expansion.
Capital costs:	$51,840
Construction date:	Started September 2008, completed December 29, 2008

Project Description:	Upgrade Harris CIS to Version 6, and replace a 5 year old server.
Need:	Regulatory - Existing hardware/software will not meet new requirements.
Scope:	Purchase Software/Server/training for the new customer billing software.
Capital costs:	$83,632
Construction date:	Started and completed in 2008.

Project Description:	Interval Meter Project.
Need:	Upgrade meters to be capable of Interval billing for our largest customers.
Scope:	21 Meters for our largest Industrial customers were upgraded.

Capital costs: $46,230
Construction date: Started and completed in 2008.

Table 2.15

Capital Projects – 2008 Actual

USoA #	Description	CCA Class	Butler Bldg	Wholesale Meters	Northern Cables	Bio-Digester	CIS Upgrade	Interval Meters	Other	Total
1808	Land and Buildings	47	$ 59,119						$ -	$ 59,119
1820	Distribution Station Equipment - Normally < 50 kV	47		$ 60,999	$ 15,127				$ 39,396	$ 115,522
1830	Poles, Towers, and Fixtures	47	$ -		$ 17,481	$ 31,042			$ 31,042	$ 79,565
1835	Overhead Conductors and Devic	47			$ 15,232	$ 19,953			$ 6,896	$ 42,081
1845	Underground Conductors & Devi	47							$ 28,871	$ 28,871
1850	Transformers	47				$ 10,007			$ 96,905	$ 106,912
1855	Services	47				$ -			$ 56,990	$ 56,990
1860	Meters	47				$ 1,821		$ 46,230	$ 1,601	$ 49,652
1910	Leasehold Improvements	13							$ 8,796	$ 8,796
1920	Computer Hardware	10					$ 24,132		$ 10,664	$ 34,796
1925	Computer Software	12		$ -			$ 59,500		$ 4,285	$ 63,785
1930	Transportation Equipment	10							$ 22,126	$ 22,126
1940	Tools and Shop Equipment	8							$ 10,817	$ 10,817
										$ -
1995	Contributions and Grants - Credit	47				-$ 11,643	$ -		-$ 90,839	-$ 102,482
Total			**$ 59,119**	**$ 60,999**	**$ 47,840**	**$ 51,180**	**$ 83,632**	**$ 46,230**	**$ 227,550**	**$ 576,550**

Capital Budget by Project – 2009:

Project Description: Altec Bucket Truck - Replaced a 1991 Ford Line Truck.
Need: Vehicle had exceeded 15 years of use, and its condition warranted replacement rather than continued repairs, and before it became unsafe to operate.
Capital costs: $248,706
Delivery Date: November 2009.

Table 2.16

Capital Projects – 2009 Actual

USoA #	Description	CCA Class	Altec Truck						Other	Total
1808	Land and Buildings	47							$ 6,568	$ 6,568
1820	Distribution Station Equipment	47							$ 1,121	$ 1,121
1830	Poles, Towers, and Fixtures	47							$ 57,191	$ 57,191
1835	Overhead Conductors and Devic	47							$ 55,864	$ 55,864
1840	Underground Conduit	47							$ 2,588	$ 2,588
1845	Underground Conductors & Devi	47							$ 10,427	$ 10,427
1850	Transformers	47							$ 42,360	$ 42,360
1855	Services	47							$ 33,811	$ 33,811
1860	Meters	47							$ 3,485	$ 3,485
1920	Computer Hardware	10							$ 18,112	$ 18,112
1925	Computer Software	12							$ 38,393	$ 38,393
1930	Transportation Equipment	10	$ 248,706						$ 18,328	$ 267,034
1940	Tools and Shop Equipment	8							$ 6,640	$ 6,640
1995	Contributions and Grants - Credit	47							$ 216	$ 216
Total			**$ 248,706**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$295,104**	**$ 543,810**

Capital Budget by Project – 2010:

Project Description:	Smart Meter Project
Need:	Regulatory compliance.
Scope:	Install Smart meters for all Residential and Commercial customers.
Capital costs:	$1,142,779
Construction date:	Started installation in 2009, and $1,142,779 is the Project Total Capital audited Costs to the end of 2010.

Capital cost is shown here as the Smart meter Project is being rolled into RSL Rate Base as part of the 2012 COS Rate Application.

Table 2.17

Capital Projects – 2010 Actual

USoA #	Description	CCA Class	Smart Meter Project						Other	Total
1820	Distribution Station Equipment	47							$ 26,423	$ 26,423
1830	Poles, Towers, and Fixtures	47							$ 24,408	$ 24,408
1835	Overhead Conductors and Devic	47							$ 49,751	$ 49,751
1845	Underground Conductors & Devi	47							$ 9,110	$ 9,110
1850	Transformers	47							$ 44,371	$ 44,371
1855	Services	47							$ 16,739	$ 16,739
1860	Smart Meters	47	$ 1,011,968							$ 1,011,968
1860	Meters	47							$ 19,068	$ 19,068
1920	Computer Hardware	10	$ 13,757						$ 2,305	$ 16,062
1925	Computer Software	12	$ 117,054						$ 35,224	$ 152,278
1930	Transportation Equipment	10							$ 37,935	$ 37,935
1940	Tools and Shop Equipment	8							$ 3,775	$ 3,775
1995	Contributions and Grants - Credit									$ -
Total			**$ 1,142,779**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 269,109**	**$ 1,411,888**

Capital Budget by Project – 2011 Bridge Year:

Project Description: LDC initiated Pole Line Reconstruction
Need: Pole Assessment - Poor
Scope: Replace poles in poor condition.
Capital costs: Poles - $45,000
Overhead Conductors - $45,000
Start date: 2011 Back Yard Pole Replacement Project

Project Description: Smart Meter Project
Need: Regulatory Compliance
Scope: Complete Installation of the rest of the Residential and Commercial Smart Meters, and supporting systems.
Capital costs: $151,311
Start date: 2011 costs to complete the project started in 2007.

Project Description:	Posi-Plus Line Truck.
Need:	Replace 1989 Mack Line Truck as Vehicle had exceeded 15 years of useful life, and its condition warranted replacement rather than continued repairs, and before it became unsafe to operate.
Capital costs:	$300,000
Delivery Date:	September 2011

Table 2.18

Capital Projects – 2011 Bridge Year

USoA #	Description	CCA Class	Pole Replacement	Line Replacement	Smart Meters	Posi Plus			Other	Total
1820	Distribution Stations	47							$ 35,000	
1830	Poles, Towers, and Fixtures	47	$ 45,000						$ 5,000	$ 50,000
1835	Overhead conductors and Devic	47		$ 45,000						$ 45,000
1845	Underground Conductors & Devi	47							$ 10,000	$ 10,000
1850	Transformers	47							$ 40,000	$ 40,000
1855	Services	47							$ 20,000	$ 20,000
1860	Smart Meters	47			$ 103,256					$ 103,256
1860	Meters	47							$ 40,000	$ 40,000
1920	Computer Hardware	10			$ 10,755				$ 10,000	$ 20,755
1925	Computer Software	12			$ 37,300				$ 10,000	$ 47,300
1930	Transportation Equipment	10				$ 300,000				$ 300,000
1940	Tools and Shop Equipment	8							$ 5,000	$ 5,000
1995	Contributions and Grants - Credit									$ -
Total			**$ 45,000**	**$ 45,000**	**$ 151,311**	**$ 300,000**	**$ -**	**$ -**	**$ 175,000**	**$ 716,311**

Capital budget by Project – 2012:

Project Description:	LDC initiated Pole Line Reconstruction
Need:	Pole Assessment - Poor
Scope:	Replace poles in poor condition.
Capital costs:	Poles - $72,310 Overhead Conductors - $50,000
Start date:	2012 Pole and Line Replacement Project

Project Description:	Inventory System
Need:	Existing Purchase Order, Work Order and Inventory system is no longer supported.
Scope:	Find financially viable alternatives, or request a rewrite in currently supported software. The existing product was custom made in 1996.
Capital costs:	$50,000
Project Dates:	Summer or Fall of 2012.

Table 2.19

Capital Projects – 2012 Test Year

USoA #	Description	CCA Class	Pole Replacement	Line Replacement	Inventory System				Other	Total
1808	Land and Buildings	47							$ 7,690	$ 7,690
1820	Wholesale Meters	47							$ 15,000	$ 15,000
1820	Distribution Stations	47							$ 20,000	$ 20,000
1830	Poles, Towers, and Fixtures	47	$ 72,310							$ 72,310
1835	Overhead conductors and Device	47		$ 50,000						$ 50,000
1845	Underground Conductors & Devi	47							$ 20,000	$ 20,000
1850	Transformers	47							$ 60,000	$ 60,000
1855	Services	47							$ 20,000	$ 20,000
1860	Smart Meters	47								$ -
1860	Meters	47							$ 40,000	$ 40,000
1920	Computer Hardware	10							$ 20,000	$ 20,000
1925	Computer Software	12			$ 50,000					$ 50,000
1930	Transportation Equipment	10								$ -
1940	Tools and Shop Equipment	8							$ 10,000	$ 10,000
1995	Contributions and Grants - Credit									$ -
Total			**$ 72,310**	**$ 50,000**	**$ 50,000**	**$ -**	**$ -**	**$ -**	**$212,690**	**$ 385,000**

10.0 ASSET MANAGEMENT PLAN SUMMARY

RSL gathers information on its asset condition through a pole inventory program, staff inspection's, and the loading and conditions of sub-transmission stations, wire, and rolling stock.

RSL's planned approach to Capital spending has not changed significantly since 2008. At that time in EB-2007-0762, the Board was satisfied that RSL's approach was appropriate in the circumstances. In its decision on EB-2007-0762, the Board stated *"The Board is satisfied that RSL's approach to this issue, it is appropriate in the circumstances".*

As RSL has been experiencing a steady decline in load over the years, asset management has been driven by regulatory requirements, by a Pole Line and Overhead Conductor reconstruction program, and by expansion information obtained from potential developers and or municipalities.

Renewal of Aging Infrastructure:

RSL's service territory includes two Villages (Iroquois and Morrisburg) combined have approximately 2200 customers representing more than a third of our total customer base. These two communities were built during the construction of the St. Lawrence Seaway late 1950's. A direct result of the building of the seaway resulted in these two communities being moved and relocated to their present day locations. The original hydro infrastructure is nearing the end of its useful life and requires replacement. Our pole replacement forecasts reflect this increase in activity which we propose to distribute over the next few years. Most of the replacement work that is left to complete is backyard work which is not as straightforward work as roadside or field work.

11.0 CAPITALIZATION POLICY

RSL's Capitalization Policy is discussed in more detail in the section "Transition to International Financial Reporting Standards, earlier in this Exhibit.

RSL follows the guidelines as set out in the OEB Accounting Procedure Handbook in the capitalization of assets. RSL does not capitalize interest on funds used during construction. RSL does not capitalize any indirect administrative support costs such as Finance, Human Resources or Corporate Services.

12.0 GREEN ENERGY ACT (GEA) PLAN SUMMARY

On September 9, 2009, Bill 150, The Green Energy and Green Economy Act, 2009 was proclaimed into force. This bill amended the Ontario Energy Board Act, 1998 and the Electricity Act, 1998 to address renewable generation connections and smart grid development.

The Board filing requirements for 2012 Cost of Service Applications require LDCs to file distribution system plans pertaining to the connection of renewable generation facilities under their deemed condition of licence. LDCs filing a cost of service rate application for 2012 and subsequent rate years must file, with the Board, a Green Energy Act Plan as part of their cost of service application.

Each distributor is required to submit its GEA Plan to the Ontario Power Authority ("OPA") for comment prior to filing and the OPA comment letter must be filed with the Cost of Service application.

RSL submitted its Basic GEA Plan to the OPA in July of 2011, and received the OPA Letter of comment dated August 29, 2011, in response to the "Basic Green Energy Act Plan" submitted by RSL.

The OPA Conclusion, as noted in section 4.0 of RSL's GEA Plan was that the discrepancy between the Plan and OPA's information regarding renewable generation may be the result of incorrect identification of the LDC name on the respective FIT and microFIT applications.

At this time, RSL is not seeking a rate rider to recover renewable generation costs.

The GEA Plan and the OPA response in included as Appendix A to this Exhibit.

13.0 SERVICE QUALITY AND RELIABILITY PERFORMANCE

RSL monitors and relies on its service quality (“ESQRs”) and reliability indices (“SAIDI, SAIFI and CAIDI") as a means of measuring system performance.

Table 2.20 below, provides RSL’s reliability performance indices for each of the measures over the period 2008-2010.

ESQR’s:

As evidenced in Table 2.20, RSL’s ESQR performance is far above the Board’s minimum requirements as specified in the Distribution System Code, revised version dated April 1, 2011.

Reliability:

RSL tracks the cause of outages and as such is able to determine whether corrective action is required to prevent or reduce similar occurrences. RSL continues to use reliability reporting as part of its Capital project planning with the intent of maintaining the reliability standards.

RSL is embedded within Hydro One Networks Inc. at eleven metering points. As such, RSL relies on Hydro One Networks Inc. for a consistent supply of energy.

Table 2.20

RSL Service Quality and Reliability Reporting

Description	Performance Requirements	2010	2009	2008	Average	Required
	% of Appointments scheduled as Required	100%	100%	n/a	100%	90%
Appointments	% of Appointments met	100%	99%	98%	99%	90%
	% of Rescheduled Missed Appointments on Time	n/a	n/a	n/a		100%
Written	% of requests for written responses provided within 10 days	100%	100%	100%	100%	80%
Phones	% of calls answered within 30 seconds	97%	98%	98%	98%	65%
	% of calls abandoned after 30 seconds	0%	0%	n/a		<10%
Connections	% of new LV services connected within 5 days	100%	100%	100%	100%	90%
	% of new HV services connected within 10 days	n/a	n/a	100%	100%	??
Emergency	% urban emergency calls responded within 60 minutes	100%	100%	100%	100%	80%
Calls	% rural emergency calls responded within 120 minutes	n/a	n/a	n/a	n/a	80%

Description	Performance Requirements	2010	2009	2008	Average
	SAIDI	0.91	0.29	2.94	1.38
	SAIFI	1.75	0.15	1.21	1.04
Reliability	CAIDI	0.52	1.96	2.44	1.64
	SAIDI - excluding loss of service	0.08	0.05	0.21	0.11
	SAIFI - excluding loss of service	0.03	0.03	0.17	0.08
	CAIDI - excluding loss of service	2.47	1.79	1.22	1.83

14.0 HST TREATMENT FOR CAPITAL

The Provincial Sales Tax ("PST") and the Federal Goods and Services Tax were harmonized into the Harmonized Sales Tax ("HST") effective July 1, 2010. As a result of this harmonization RSL allocated into account 1592, the net reduction in costs in the form of Input Tax Credits ("ITCs").

This net reduction is the result of cost decreases from the receipt of additional ITCs on the purchases of goods and services previously subject to PST that become subject to the HST.

These cost decreases are partially offset by cost increases on certain items that were not previously subject to PST but become subject to the HST with no additional ITCs having been granted (i.e., these items are subject to recaptured ITC requirements).

RSL has also identified and accounted for the HST changes in the capital budget process and in the budgeted OM&A to reflect the implementation of the HST.

RSL confirms that the steps taken in the budgeting process ensures that capital and OM&A costs contained in the application test year exclude all impacts of PST previously embedded in costs for the historical years.

APPENDIX A – GREEN ENERGY PLAN

Rideau St. Lawrence Distribution Inc.
Green Energy Plan

Prepared by:
Automated Solutions International Inc. - Peter Krotky, P.Eng.

Support by:
Rideau St. Lawrence Distribution Inc. - John Walsh, President

July 2011

Table of Contents

1.0 Introduction

As required by the OEB document EB-2009-0397, the objectives of this GEA plan are as follows:

a. Provide information to the Board and interested stakeholders regarding the readiness of the distributor's system to accommodate the connection of renewable generation (RG) and the expansion and/or reinforcement necessary to accommodate RG and the eventual development and implementation of a smart grid;

b. Provide a basis, through the approval of a GEA Plan, by which all of the costs of an expansion to connect RG facilities will be the responsibility of the distributor under the DSC, and therefore also eligible for recovery through the provincial cost recovery mechanism, as set out in section 79.1 of the OEB Act;

c. Provide evidence in proceedings for approvals related to infrastructure investments for renewable generation (and where applicable, smart grid) and the recovery of the resulting costs from ratepayers.

This is intended to be a Basic GEA plan rather than a detailed GEA Plan, as outlined in EB-2009-0397.

Rideau St. Lawrence Distribution Inc. (RSL) services six communities - Town of Prescott, and the Villages of Westport, Cardinal, Iroquois, Morrisburg and Williamsburg, in Eastern Ontario. The six communities are mature areas with a customer density of 60 customers per kilometer of line. The distribution network includes nine distribution stations owned by RSL and two stations that are shared with Hydro One Networks Inc. (HONI). The system consists of 9 km of underground lines, 97 kilometers of overhead lines supported by 1924 poles and 735 utility owned transformers. The distance from the eastern most community to the western most community is 130 km. The utility has a total service area of 18 km^2, with a service area population of 9,900, and municipal population of 20,922. There is no rural service area. The RSL distribution system is fully embedded in the HONI system.

Over the past 15 years, there has been minimal expansion to the distribution systems servicing these areas. This is supported by the Table 1 below. The distribution systems serviced by RSL are also isolated from one another and operated independently. All areas are in good operating condition and do not require any immediate remedial action. RSL employs a normal maintenance and replacement strategy to ensure ongoing reliability, and to ensure a leveling of capital and maintenance expenditures.

Table 1 shows a trend over the past six years – the following observations can be made:

- the total customer base is relatively unchanged
- the service area is constant
- the system load and kWhs sold has been declining

Table 1 - RSL General Statistics as of December 31, 2010

	2005	2006	2007	2008	2009	2010
Population Served	9,900	9,900	9,900	9,900	9,900	9,900
Municipal Population	16,700	16,700	16,700	16,700	16,700	16,700
Seasonal Population	0	0	0	0	0	0
Total Customers	5,823	5,839	5,864	5,859	5,863	
Residential Customers	4,931	4,962	4,967	4,966	4,974	4,982
General Service <50 kW Customers	825	812	832	827	774	770
General Service >50 kW Customers	67	65	65	66	66	66
Large User (>5000 kW) Customers	0	0	0	0	0	0
Total Service Area (km²)	18	18	18	18	18	18
Rural Service Area (km²)	7	7	7	7	7	7
Urban Service Area (km²)	11	11	11	11	11	11
Total kWh sold (excluding losses)	126,336,727	116,598,828	113,998,664	111,785,106	110,633,517	107,839,547
Total Distribution Losses (kWh)	4,992,578	9,486,742	11,562,896	9,549,534	7,781,309	8,753,154
Total kWh Purchased	131,329,305	126,085,570	125,561,560	121,334,640	118,414,826	116,592,701
Winter Peak (kW)	25,475	29,587	32,731	39,622	26,268	29,160
Summer Peak (kW)	22,345	21,274	31,422	21,598	18,378	32,187
Average Peak (kW)	21,620	21,222	23,280	21,600	19,194	21,989

2.0 Current Assessment of RSL System

RSL operates a 44kV sub-transmission system in four of the six areas, a 4.16kV system in three areas and an 8.32kV system in the remaining three areas. All areas are fully embedded within the HONI system. The feeder capacity of the 44kV system is determined by HONI. Based on information provided by them, there are no known feeder capacity issues to affect the processing of distributed generation applications. Table 2 below indicates the feeder capacities of all 4.16 and 8.32kV stations which are also at low levels to allow accommodation of reasonable size distributed generation applications. RSL has seen few applications, all of which have been for rooftop solar installations under 10kW. To date, 36kW of RG projects have been approved for connection to RSL systems in four communities. An additional 36kW of RG load has been identified, however, the proponents have not proceeded with their application to date.

The RSL distribution system evolved independently in each area serviced. More importantly, the system components, on the whole, are not stressed in their daily operation and supply of energy to the customer base. The systems are primarily designed to service small urban loads over short distances. Based on this the systems are in good operational order.

Table 2 Renewable Generation Capacity by Station/Feeder

	Peak kW	Min kW	FIT Capacity (kW)
PRESCOTT (4.16kV)			
QL2	2,087	26.0%	
2F1	447	116.2	8
2F2	656	170.5	12
2F3	985	256.0	18
QL30	1,026	37.7%	
30F1	584	220.0	15
30F2	442	166.6	12
QL40	2,704	37.7%	
40F1	841	316.9	22
40F2	697	262.6	18
40F3	1,167	440.1	31
QL20	709	37.7%	
20F2	709	267.1	19
CARDINAL (4.16kV)			
Station #1	817	24.0%	
23F1	817	196.0	14
23F2	0	0	0
Station #2	795	27.5%	
33F4	437	120.2	8
33F5	358	98.4	7
IROQUOIS (8.32kV)			
Station #1	2,061	35.2%	
F1	1,316	463.3	32
F2	745	262.1	18
MORRISBURG (4.16kV)			
MS1	3,096	42.3%	
46F1	1,256	531.4	37
46F2	668	282.4	20
46F3	348	147.3	10
46F4	824	348.5	24
MS2	1,275	42.3%	
2F1	665	281.4	20
2F2	610	258.1	18
WESTPORT (8.32kV)			
PME		337.1	24
WILLIAMSBURG (8.32kV)			
PME		150.6	11

3.0 Current Capacity to Accommodate Renewable Generation Facilities

3.1 Capacity Assessment by Service Area

RSL has experienced load reductions over the past few years, resulting in lightly loaded distribution system feeders, particularly during off-peak periods. This creates greater technical and safety concerns for connection of renewable generation projects. All RG projects larger than 10kW would require a CIA study as part of a connection assessment.

3.1.1 Prescott

The distribution system in Prescott consists of two subsystems:

a. A 44kV three-wire system, supplied from the HONI operated Morrisburg TS 18M23 and Brockville TS 24B1R, which serve as the bulk delivery system for the four local 4.16kV substations and also directly serving some large load customers.

   - Any point on the RSL system is within 3 km of the 44kV network, should an extension be required to accommodate the connection of a large RG project
   - The 44kV system is embedded in the HONI system; only the station and customer taps are operated and maintained by RSL. This network should be robust enough to accommodate most proposed RG projects. A detailed CIA would have to be performed and coordinated with HONI to ensure that no technical issues exist to prevent the connection of such a project.

b. A 4.16kV grounded-wye distribution system, consisting of four substations and a number of overhead and underground distribution transformers supplying the required loads. The distribution system lines are mainly 3/0 ACSR three-phase primary and 1/0 ACSR taps.

   - It is likely that larger loads would require connection directly to the 44kV network
   - As a lower capacity distribution system, it was never intended to connect large load customers directly to this system. It has been a normal past practice for RSL to connect loads larger than 350kVA directly to the 44kV HONI system. A similar constraint would also be placed on an RG project.
   - The 4.16kV system was built to supply smaller local loads. Due to load reductions on this system, the feeders are lightly loaded, particularly during off-peak periods. This creates greater technical and safety concerns for connection of RG projects.
   - Parts of the system were originally built using smaller conductor and may limit the capacity to connect potential RG proponents. These limited sections of conductor will be replaced as part of the RSL asset management plan.

3.1.2 Morrisburg

The distribution system in Morrisburg consists of two subsystems:

a. A 44kV three-wire system, supplied from the HONI operated Morrisburg TS 18M26, which serves as the bulk delivery system for the two local 4.16kV substations and also directly serving some large load customers.

   - Any point on the RSL system is within 2 km of the 44kV network, should an extension be required to accommodate the connection of a large RG project
   - The 44kV system is embedded in the HONI system; only the station and customer taps are operated and maintained by RSL. This network should be robust enough to accommodate most proposed RG projects. A detailed CIA would have to be performed and coordinated with HONI to ensure that no technical issues exist to prevent the connection of such a project.

b. A 4.16kV grounded-wye distribution system consisting of two substations and a number of overhead and underground distribution transformers supplying the required loads. The distribution system lines are mainly 3/0 ACSR three-phase primary and 3/0 and 1/0 ACSR taps.

   - It is likely that larger loads would require connection directly to the 44kV network

- As a lower capacity distribution system, it was never intended to connect large load customers directly to this system. It has been a normal past practice for RSL to connect loads larger than 350kVA directly to the 44kV HONI system. A similar constraint would also be placed on an RG project.
- The 4.16kV system was built to supply smaller local loads. Due to load reductions on this system, the feeders are lightly loaded, particularly during off-peak periods. This creates greater technical and safety concerns for connection of RG projects.

3.1.3 Iroquois

The distribution system in Iroquois consists of two subsystems:

a. A 44kV three-wire system, supplied from the HONI operated Morrisburg TS 18M25, which serves as the bulk delivery system for the single local 8.32kV substations and also directly serving some large load customers.

- Any point on the RSL system is within 2 km of the 44kV network, should an extension be required to accommodate the connection of a large RG project
- The 44kV system is embedded in the HONI system; only the station taps are operated and maintained by RSL. This network should be robust enough to accommodate most proposed RG projects. A detailed CIA would have to be performed and coordinated with HONI to ensure that no technical issues exist to prevent the connection of such a project.

b. A 8.32kV grounded-wye distribution system, consisting of a single substation and a number of overhead and underground distribution transformers supplying the required loads. The distribution system lines are mainly 3/0 ACSR throughout.

- It is likely that larger loads would require connection directly to the 44kV network operated by HONI.
- As a lower capacity distribution system, it was never intended to connect large load customers directly to this system. It has been a normal past practice for RSL to connect loads larger than 350kVA directly to the 44kV HONI system. A similar constraint would also be placed on an RG project.
- The 8.32kV system was built to supply smaller local loads. Due to load reductions on this system, the feeders are lightly loaded, particularly during off-peak periods. This creates greater technical and safety concerns for connection of RG projects.

3.1.4 Cardinal

The distribution system in Cardinal consists of two subsystems:

a. A 44kV three-wire system, supplied from the HONI operated Morrisburg TS 18M23, which serves as the bulk delivery system for the two local 4.16kV substations and also directly serving some large load customers.

- Any point on the RSL system is within 1 km of the 44kV network, should an extension be required to accommodate the connection of a large RG project
- The 44kV system is embedded in the HONI system; only the station taps and one large load customer are operated and maintained by RSL. This network should be robust enough to accommodate most proposed RG projects. A detailed CIA would have to be performed and coordinated with HONI to ensure that no technical issues exist to prevent the connection of such a project.

b. A 4.16kV grounded-wye distribution system, consisting of a two substations and a number of overhead and underground distribution transformers supplying the required loads. The distribution system lines are mainly 3/0 ACSR three-phase primary and 1/0 ACSR taps.

- It is likely that larger loads would require connection directly to the 44kV network
- As a lower capacity distribution system, it was never intended to connect large load customers directly to this system. It has been a normal past practice for RSL to connect loads larger than 350kVA directly to the 44kV HONI system. A similar constraint would also be placed on an RG project.

- The 4.16kV system was built to supply smaller local loads. Due to load reductions on this system, the feeders are lightly loaded, particularly during off-peak periods. This creates greater technical and safety concerns for connection of RG projects.
- Parts of the system were originally built using smaller conductor and will limit the capacity to connect potential RG proponents. These limited sections of conductor will be replaced as part of the RSL asset management plan.

3.1.5 Williamsburg

The distribution system in Williamsburg is a single non-dedicated 8.32kV grounded-wye feeder supplied by the HONI operated Glen Becker DS. The distribution system consists of a number of overhead and underground distribution transformers supplying the required loads. The distribution system lines are mainly 1/0 ACSR throughout.

- It is likely that larger loads may not be accommodated and would be referred to HONI.
- The 8.32kV system was built to supply smaller local loads.
- The majority of the system was rebuilt about 15 years ago. The system is in good condition to accommodate any small RG project, less than 10kW. For any RG project greater than 10kW, a detailed CIA would have to be performed and coordinated with HONI to ensure that no technical issues exist to prevent the connection of such a project.

3.1.6 Westport

The distribution system in Westport is a single non-dedicated 8.32kV grounded-wye feeder supplied by the HONI operated Newboro DS. The distribution system consists of a number of overhead and underground distribution transformers supplying the required loads. The distribution system lines are mainly 1/0 ACSR throughout.

- It is likely that larger loads may not be accommodated and would be referred to HONI.
- The 8.32kV system was built to supply smaller local loads.
- The majority of the system was rebuilt about 15 years ago. The system is in good condition to accommodate any small RG project, less than 10kW. For any RG project greater than 10kW, a detailed CIA would have to be performed and coordinated with HONI to ensure that no technical issues exist to prevent the connection of such a project.

3.2 Capacity Assessment Methodology

Based on current information and industry practice, RSL has adopted a limit of 7% of the minimum feeder load for RSL owned 4.16kV and 8.32kV feeders. This is founded on the fact that most problems with reverse power flow will occur under light loading conditions. The relatively light load on most RSL feeders generate a limit of potential RG load of 20kW to 50kW per feeder.

It is also imperative to ensure that reliable service to existing customers is not impacted by the addition of new RG projects. Since RSL does not own nor have any dedicated 44kV feeders, RSL is limited by HONI guidelines and limits on the 44kV network.

3.3 Factors Limiting RSL Ability to Connect Renewable Generation Facilities

RSL loads are completely embedded in a HONI 8.32kV or 44kV feeder – as such, there may be constraints in the HONI network that impact the capacity for RSL's system. As a result of being embedded, both RSL and HONI also have load transfer customers with each other that they must consider and be aware of.

None of the stations supplying RSL areas are capacity restricted at this time.

3.4 Expenditures Related to Renewable Generation Connection

To date, RSL has not expended any costs to accommodate the connection of RG projects.

3.5 Relevant Unique Challenges and Opportunities

RSL is completely embedded in the HONI 8kV or 44kV systems. All applications for RG greater than 10kW will have to be coordinated with HONI.

3.5.1 Prescott

One Prescott DS is supplied by Brockville TS and the other three DS's by Morrisburg TS. Based on HONI information, these TS's cannot be tied together. This restricts RSL in the operation of the 4.16kV distribution system. This situation would be further compounded by the addition of RG loads. Due to this condition and also the light loading on the feeders, RSL will need to be cognizant of operating procedures, during planned and emergency situations, to ensure that RG loads during transfers do not exceed the proposed limits.

3.5.2 Westport and Williamsburg

RSL does not own the DS supplying either of these areas.

3.5.3 Islanding

In all service areas, RSL is embedded and supplied from a single source of supply. As such, islanding, due to RG issues, may be a concern.

4.0 Planned Development of the System to Accommodate Renewable Generation Connections

It should be noted that currently, there are no FIT applications and only eight current connection requests, at various stages of implementation. RSL is aware of the information published by the OPA. A number of the applications are not within our service territory. In this report, we have only included those applications that are within our service territory. In this general geographic area, most RG applications are for small solar rooftop installations. Applications for larger RG projects tend to require larger land acreage. Since all of the RSL areas are small urban, RSL is not likely to see any applications for these types of projects.

4.1 Renewable Generation Connections Anticipated Over the Five Year Plan Period

4.1.1 Micro (<10kW) Renewable Generation Connections Forecast

a. Current Connections
To date, RSL has connected two projects, has issued offers to connect to three more and has been able to accommodate their connections to the existing local distribution system with no significant expansion or enhancement of its distribution system. It is anticipated that this trend will continue in the future.

b. Future Connections
It is anticipated that RSL will continue to see similar types of applications, as we have seen to date and with a similar frequency. In other words, about two RG connections per year, spread over the six areas.

Table 3 shows current and proposed RG applications RSL is aware of.

Table 3 - Renewable Generation Connections Summary

CUSTOMER	AREA	STN-FDR	kW	Type	STATUS
Burchell	Cardinal	23F1	10	Solar PV	Connected
Sohos	Westport		9.88	Solar PV	Connected
Upper Canada District School Board	Iroquois	MS1F1	10	Rooftop Solar PV	To be Connected
St Lawrence Self Storage	Iroquois	MS1F2	10	Solar PV	To be Connected
Rolf Lehman	Morrisburg	46F4	6.2	Rooftop Solar PV	To be Connected
Gary Baskin	Prescott	30F1	5	Rooftop Solar PV	Proposed
G&S Kinghorn Enterprises	Cardinal	33F4	10	Rooftop Solar PV	Proposed
Richard Roffey	Morrisburg	46F4	1.5	Solar PV	Proposed

4.1.2 Larger (>10kW) Forecasted Renewable Generation Connections

a. Current Connections
RSL currently does not have any RG projects larger than 10kW.

b. Future Connections
According to local newspapers, in a rural area outside of Brockville, there are some large FIT applications for ground mounted solar projects. A similar application for ground mounted solar installation is taking place in the Johnston area, which is also rural.

It is anticipated that RSL will not see these types of applications – this is based on past history and the reasons cited above.

4.2 Infrastructure Projects and Activities

As outlined in section 4.1 above, RSL has not identified any specific RG projects or expenditures that are known to be required in the five year planning horizon. If and when such a project is identified, RSL will perform the appropriate CIA review and adjust this plan accordingly.

4.3 Recoverable Costs

Where costs may be recovered from provincial ratepayers, a calculation of the direct benefits accruing to the distributor's customers, consistent with the Board's policy, will be made.

4.4 Methodology for Prioritization of Expenditures

As outlined in section 4.1 above, RSL has not identified any specific RG projects or expenditures that are known to be required in the five year planning horizon – prioritization is not required at this time. If and when such a project or expenditures are identified, RSL will perform the appropriate review and adjust this plan accordingly.

4.5 Consultation Process

RSL is effectively imbedded within the HONI 8.32kV and 44kV systems. As such, all applications received will require to be referred to HONI for review. RSL would engage with HONI to discuss the proposed RG project to be connected to the main feeder. This would occur over a number of consultations with HONI specialists in the preparation of a CIA study performed by both RSL and HONI. The purpose of the consultation would be to resolve any technical issues and ensure appropriate preparation of each parties CIA studies, as required. RSL would engage in further consultation with OPA, as required, on a project basis.

5.0 Direct Benefits Accruing to Customers of a Distributor

RSL has not identified any specific RG projects or expenditures that may be required in the five year planning period. When a project is identified, RSL will comply with the most recent Board direction with respect to the calculation or quantification of the direct benefits and file information with the Board consistent with the policy.

6.0 Letter of Comment from OPA

The letter of comment from the OPA is attached at the end of this report (Appendix A).

7.0 Smart Grid Development

RSL has completed the mandatory installation of Smart Meters and continues to evolve the supporting systems to provide additional value for daily operation.

7.1 Smart Grid System Initiatives

RSL operates six separate areas, urban in nature and a relatively simple distribution system network. Expensive SCADA systems would have relatively minimal value to enhance daily operations or visible results in improving customer service or reliability. It is also uncertain what value a SCADA system would provide RSL as a basis for the development of a Smart Grid. This can be better assessed once the concept of Smart Grid is better defined.

It is recognized, however, that there is a greater need for information to make sound business and management decisions. To complement the Smart Meters, RSL is considering the implementation of monitoring equipment, primarily at the station feeder level. It is also possible to utilize the existing Primary Metering Equipment (PME) locations to provide additional information at the network level. This type of implementation would assist RSL with the normal daily operations of the distribution system and would be considered to be good utility practice and not considered as part of a GEA Plan implementation or investment.

RSL is also currently in the process of implementing a GIS system. Together, these systems will provide RSL with the ability to effectively collect and analyze asset and operational information related to the distribution system. These in turn will support any Smart Grid initiative, even though not all were necessarily considered Smart Grid investments.

7.2 Activities During Planning Period

During the five year planning period, we do not expect to undertake any smart grid initiative projects. Although EB-2009-0397 allows for smart grid development activities and expenditures, limited to smart grid demonstration projects, smart grid studies or planning exercises and smart grid education and training, RSL will not be engaging in any of these activities.

8.0 Reporting

8.1 GEA Plan Annual Status Report

RSL will file annual status reports on the implementation of the approved GEA Plan, highlighting any deviations. The reporting shall be completed in accordance with the Boards then current directive.

8.2 Smart Grid Development Activity Report

RSL is not planning to undertake any activities or expenditures, specifically justified for the Smart Grid. Although there is mention of some activities in section 7 above, these would have been undertaken even if the Smart Grid was not identified in the GEA plan. RSL does not intend to prepare any reports designed to specifically address the Smart Grid.

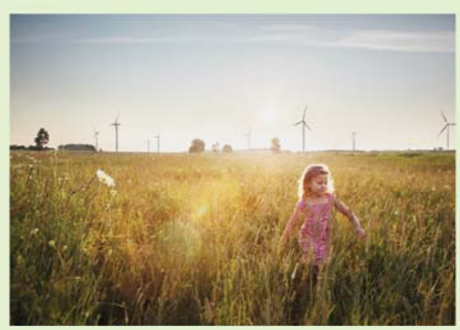
Appendix A – OPA Letter of Comment

OPA Letter of Comment:

Rideau St. Lawrence Distribution Inc.

Basic Green Energy Act Plan

August 29, 2011



ONTARIO POWER AUTHORITY

Introduction

On March 25, 2010, The Ontario Energy Board ("the OEB") issued its Filing Requirements for Distribution System Plans. As a condition of Licence, Ontario Distributors are required to file a Green Energy Act Plan as part of their cost of service application.

The Filing Requirements distinguish between Basic and Detailed Green Energy Act Plans ("Plan" or "GEA Plan") and outline the specific information and level of detail which must be provided for each type of Plan. Recognizing the importance of coordinated planning in achieving the goals of the *Green Energy and Green Economy Act, 2009* (the "GEA"), distributors must consult with embedded and host distributors, upstream transmitters and the OPA in preparing their Plans. For both Basic and Detailed Plans, distributors are required to submit as part of the Plan, a letter of comment from the OPA.

The OPA will review distributors' Basic Plans to ensure consistency with regard to FIT and microFIT applications received, as well as with integrated Plans for the region or the system as a whole.

Rideau St. Lawrence Distribution Inc. Basic Green Energy Act Plan

On July 29, 2011, the OPA received a Basic GEA Plan from Rideau St. Lawrence Distribution Inc. ("RSL"). The OPA has reviewed RSL's Plan and has provided its comments below.

OPA FIT/microFIT Applications Received

RSL's Plan identifies 0 FIT applications and 8 microFIT applications received as shown in section 4.0 *Planned Development of the System to Accommodate Renewable Generation Connections* on page 9.

To date, the OPA has received 3 capacity allocation exempt FIT applications for projects between 10 kW and 500 kW, and 50 microFIT applications for projects under 10 kW, connecting to RSL's system. This represents a total of 1,300 kW of FIT applications and 423 kW of microFIT applications. At this time, 2 microFIT applications have been connected, 20 microFIT applications have been terminated, and 7 microFIT applications are under OPA's review (leaving 21 applications totalling 171 kW of capacity to be connected).

Upstream Transmission Constraints

RSL's GEA Plan noted that there is no capacity restriction at the stations supplying the RSL area. According to the OPA's information, neither Brockville TS nor Morrisburg TS is currently constrained. However, both transformer stations have limited remaining capacity to accommodate additional generation beyond the existing FIT and microFIT contracts.

Economic Connection Test Results

There has been no Economic Connection Test performed to date.

Opportunities for Integrated Solutions

There are no known corresponding expansions among neighbouring LDCs that could be addressed through integrated transmission solutions at this time.

Conclusion

As noted in section 4.0 of RSL’s GEA Plan, the discrepancy between the Plan and OPA’s information regarding renewable generation may be a result of incorrect identification of the LDC name on the respective FIT and microFIT applications.

The OPA appreciates the opportunity to comment on RSL’s Basic GEA Plan.

Exhibit 3 Operating Revenue

1.0 OVERVIEW OF OPERATING REVENUE

This Exhibit provides the details of Rideau St. Lawrence Distribution Inc.'s (RSL) operating revenue for 2008 Board Approved, 2008 Actual, 2009 Actual, 2010 Actual, the 2011 Bridge Year and the 2012 Test Year. This Exhibit also provides a detailed variance analysis by rate class of the operating revenue components. Distribution revenue excludes revenue from commodity sales.

Rideau St. Lawrence Utilities Inc. is proposing a total Service Revenue Requirement of $2,735,672 for the 2012 Test Year. This amount includes a Base Revenue Requirement of $2,528,129 plus revenue offsets of $207,543 to be recovered through Other Distribution Revenue.

A summary of all operating revenue is presented below in Table 3.1 and provides a comparison of total revenues from the 2008 OEB approved year to the 2012 Test Year, and variances year over year.

Table 3.1

Other Operating Revenues

	2008 Board	2008	2008 Board	2009	from 2008	2010	from 2009	2011	from 2010	2012	from 2011
Summary	Approved	Actual	Approved	Actual	Actual	Actual	Actual	Bridge	Actual	Test	Bridge
	$	$	$	$	$	$	$	$	$	$	$
Distribution Revenue											
Residential	1,123,163	1,040,276	-82,887	1,156,502	116,226	1,147,032	-9,470	1,140,354	-6,678	1,453,328	312,974
GS< 50 kW	394,398	300,610	-93,788	375,059	74,449	378,223	3,164	379,379	1,156	479,683	100,304
GS> 50 kW	374,934	337,523	-37,411	354,195	16,672	346,031	-8,163	346,282	251	460,657	114,375
Street Light	62,039	57,337	-4,702	77,353	20,016	85,309	7,957	80,479	-4,830	104,007	23,528
Sentinel Light	2,958	2,855	-103	4,063	1,208	4,070	7	3,839	-231	4,967	1,128
Unmetered Scattered Load	14,198	15,184	986	16,617	1,432	15,968	-649	19,375	3,407	25,487	6,112
Total	1,971,690	1,753,785	-217,905	1,983,789	230,004	1,976,634	-7,155	1,969,708	-6,926	2,528,129	558,421
Other Distribution Revenue											
Specific Service Charges	94,264	119,859	25,595	102,692	-17,167	104,819	2,127	93,160	-11,659	88,900	-4,260
Late Payment Charges	52,700	47,320	-5,380	52,703	5,383	44,526	-8,177	34,093	-10,433	32,400	-1,693
Other Distribution Revenue	73,886	77,166	3,280	66,905	-10,261	89,659	22,754	74,975	-14,684	74,243	-732
Other Income & Expenses	31,000	26,583	-4,417	4,517	-22,066	8,019	3,502	12,000	3,981	12,000	0
Total	251,850	270,927	19,077	226,817	-44,110	247,022	20,205	214,228	-32,794	207,543	-6,685
Grand Total	2,223,540	2,024,712	-198,828	2,210,606	185,894	2,223,656	13,050	2,183,936	-39,720	2,735,672	551,736

2.0 WEATHER NORMALIZATION METHODOLOGY

The purpose of weather normalization is to predict future customer consumption based on normal weather conditions. To achieve this goal, the relationship between weather change and customer consumption must be defined. RSL reviewed the various processes used by earlier Cost of Service applicants and is proposing to adopt a weather normalization methodology using Multifactor Regression (MR) for its load forecast. RSL is proposing to adopt a weather normalization forecasting method similar to the one approved by the Board in a number of Cost of Service rate applications over the past three years.

In summary, RSL has used the regression analysis methodology to determine a prediction model. With regards to the overall process of load forecasting, it is RSL's view that conducting a regression analysis on historical purchases to produce an equation that will predict energy purchases is appropriate. RSL knows by month the exact number of kWh's purchased from the IESO for use by customers of RSL. With a regression analysis these purchases can be related to other monthly explanatory variables such as heating degree days and cooling degree days which occur in the same month. The result of the regression analysis produces an equation that predicts the purchases based on the explanatory variables. This prediction model is then used as the basis to forecast the total level of weather normalized purchases for RSL for the bridge and test year, which is converted to Billed kWh by rate class. A detail explanation of the process is provided later in this Exhibit.

During the review process of 2009 cost of service applications, Intervenors expressed concerns with the load forecasting weather normalization process being proposed by RSL. Intervenors suggested the weather normalization should be conducted on an individual rate class basis and the regression analysis on an individual rate class basis.

The ability for RSL to forecast on an individual rate class basis will be possible when smart meters are fully deployed and actual monthly consumption by rate class and individual customer can be determined for a number of historical years. As a result, conducting the regression analysis on purchases provides better results since a higher level of historical data increases the accuracy of the regression analysis.

The following Tables provide the material to support the weather normalized load forecast used by RSL in this application. Tables 3.2, 3.3, and 3.4 below provide a summary of the weather normalized load and customer/connection forecast used in this section.

The years 2004 to 2010 are weather actual, adjusted for the loss of a manufacturing Industrial customer who went bankrupt in January 2006 (6.6% of billed kwh's in 2004-5), 2011 and 2012 are weather normalized and adjusted by projected CDM savings.

In EB-2007-0762, the Board approved the reduction to annual estimated kwh's of 1.5 million, from 10 million, for the bankrupt manufacturing facility that was sold and turned into a warehousing type operation in 2006. The first run for the weather normalized projection for 2012, with the actual history for this customer in the data, was predicting too low for the annual kwh's – result was under 100 million predicted kwhs for 2012.

Once we reduced the historical kwh volumes for this customer, to the actual average for the last three years consumption, the results were acceptable, and the R Square was 97%.

Total Customers are annual averages and street light, and sentinel lights, are measured as connections.

Table 3.2

Summary of Load and Customer/Connection Forecast						
Year	Billed (kWh)	Growth (kwh)	Percentage Change %	Customer/ Connection Count	Growth	Percentage Change %
2004	126,191,356			7,441		
2005	126,336,267	144,911	0.11%	7,506	65	0.87%
2006	116,814,435	-9,521,832	-7.54%	7,556	50	0.67%
2007	113,998,664	-2,815,771	-2.41%	7,575	19	0.25%
2008	111,785,106	-2,213,558	-1.94%	7,563	-12	-0.16%
2009	109,680,577	-2,104,529	-1.88%	7,578	15	0.20%
2010	107,839,547	-1,841,030	-1.68%	7,642	64	0.84%
2011	106,733,113	-1,106,434	-1.03%	7,679	37	0.48%
2012	104,537,301	-2,195,811	-2.06%	7,693	14	0.19%

On a rate class basis, actual and forecasted billed amount and number of customers, are shown in Table 3.3 and customer usage is shown in Table 3.4.

Table 3.3

Billed Energy and Number of Customers by Rate Class

Year	Residential	General Service < 50kW	General Service 50 - 4999 kW	Large User	Streetlights	Sentinel Lights	Unmetered Scattered Load	Total
Energy (kWh)								
2004	45,034,614	23,384,526	56,110,937	-	1,358,901	96,156	206,222	126,191,356
2005	46,438,361	23,490,754	54,683,320	-	1,359,556	94,884	269,392	126,336,267
2006	44,440,685	22,220,025	48,405,425	-	1,341,413	102,394	304,493	116,814,435
2007	45,086,486	22,360,087	44,734,117	-	1,392,325	102,933	322,716	113,998,664
2008	44,465,236	21,119,955	44,381,852	-	1,394,217	100,161	323,685	111,785,106
2009	44,337,599	20,399,815	43,092,665	-	1,393,923	108,556	348,019	109,680,577
2010	44,191,614	20,418,777	41,354,016	-	1,429,699	108,277	337,164	107,839,547
2011	44,684,949	20,245,025	39,840,492	-	1,435,688	108,277	418,681	106,733,113
2012	44,584,446	19,806,495	38,166,401	-	1,441,722	108,277	429,961	104,537,301

Number of Customers/Connections

Year	Residential	General Service < 50kW	General Service 50 - 4999 kW	Large User	Streetlights	Sentinel Lights	Unmetered Scattered Load	Total
2004	4,869	761	70	0	1,635	56	50	7,441
2005	4,931	770	67	0	1,633	56	49	7,506
2006	4,962	771	65	0	1,641	67	50	7,556
2007	4,967	784	65	0	1,644	67	48	7,575
2008	4,966	778	66	0	1,637	67	49	7,563
2009	4,974	774	66	0	1,640	75	49	7,578
2010	4,982	770	66	0	1,701	75	48	7,642
2011	5,006	770	66	0	1,705	75	58	7,679
2012	5,016	770	66	0	1,709	75	58	7,693

Table 3.4

Annual kWh Usage per Customer/Connection							
Year	Residential	General Service < 50kW	General Service 50 - 4999 kW	Large User	Streetlights	Sentinel Lights	Unmetered Scattered Load
2004	9,249	30,729	801,585	-	831	1,717	4,124
2005	9,418	30,507	816,169	-	833	1,694	5,498
2006	8,956	28,820	744,699	-	817	1,528	6,090
2007	9,077	28,521	688,217	-	847	1,536	6,723
2008	8,954	27,146	672,452	-	852	1,495	6,606
2009	8,914	26,356	652,919	-	850	1,447	7,102
2010	8,870	26,518	626,576	-	841	1,444	7,024
2011	8,809	25,874	601,374	-	842	1,403	7,243
2012	8,747	25,247	577,185	-	844	1,363	7,469

Annual Growth Rate in kWh Usage per Customer/Connection							
Year	Residential	General Service < 50kW	General Service 50 - 4999 kW	Large User	Streetlights	Sentinel Lights	Unmetered Scattered Load
2004							
2005	1.0182	0.9928	1.0182	0.0000	1.0017	0.9868	0.0000
2006	0.9510	0.9447	0.9124	0.0000	0.9818	0.9020	0.0000
2007	1.0135	0.9896	0.9242	0.0000	1.0361	1.0053	0.0000
2008	0.9864	0.9518	0.9771	0.0000	1.0056	0.9731	0.0000
2009	0.9955	0.9709	0.9710	0.0000	0.9980	0.9682	1.0752
2010	0.9951	1.0061	0.9597	0.0000	0.9889	0.9974	0.9890
2011 Normalized	0.9931	0.9757	0.9598	0.0000	1.0019	0.9715	1.0312
2012 Normalized	0.9931	0.9757	0.9598	0.0000	1.0019	0.9715	1.0312

Note that Table 3.4, Annual Growth Rate in kWh Usage per Customer/Connection, presents Sentinel Lights, and USL with an annual growth rate in usage/customer or connection as a 1.0 growth rate. This is based on both trending in our distribution area, as well as industry and local growth knowledge. Ten (10) new Unmetered Scattered Load accounts for a cable company, were added in early 2011, and have been included as a full year for our customer count in 2011.

Load Forecast & Methodology:

RSL's weather normalized load forecast is developed in a three-step process. First, a total system weather normalized purchased energy forecast is developed based on a multifactor regression analysis that incorporates historical load, weather, economic and other variables described below. Second, the weather normalized purchased energy forecast is adjusted by a historical loss factor to produce a weather normalized billed energy forecast. Finally, the forecast of billed energy by rate class is developed based on a forecast of customer numbers and historical usage patterns per customer. For the rate classes that have weather sensitive load, their forecasted billed energy is adjusted to ensure that the total billed energy forecast by rate class is equivalent to the total weather normalized billed energy forecast that has been determined from the regression analysis.

The forecast of customers by rate class is determined using a geometric mean analysis. For those rate classes that use kW for the distribution volumetric billing an average kW/kWh factor analysis was also used to calculate the future kW.

The following explains the forecasting process in more detail.

Purchased kWh Load Forecast:

An equation to predict total system purchased energy is developed using a multifactor regression model with the following independent variables: weather (heating and cooling degree days), population, calendar variables (days in month, seasonal), and monthly peak hours. The regression model uses monthly purchased kWh and monthly values of independent variables from January 2004 to December 2010 to determine the monthly regression coefficients.

Data for RSL's total system load beginning in January 2004 was used, less the reduction for a manufacturing customer going bankrupt in 2006, and the new owners using less than 10% of the former owner. This provides a reasonable data set for use in a multifactor regression analysis. It is RSL's view that it is appropriate to review the impact of weather since 2004 on the energy usage, and then determine the average weather conditions from January 2004 to December 2010, which would be applied in the forecasting process to determine a weather normalized forecast.

In accordance with the filing requirement RSL has also provided a comparison of the average of heating and cooling days used in this application, 10 and 20 year trend of data in Table 3.5.

Table 3.5

Summary of Degree Day Information Source of Data: Ottawa Weather Station

Summary of All Heating Degree Days

Month	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	Model	7 Year Avg	10 Year Avg	20 Year Trend
January	887	917	630	1,116	774	920	923	802	875	875	848	709	977	1,045	921	734	797	754	980	789	833	860	855	844
February	674	802	791	833	796	783	736	610	671	728	747	669	842	750	701	721	820	774	712	656	731	733	739	718
March	597	745	604	638	537	656	678	576	646	502	652	652	675	559	669	600	643	721	598	461	614	607	623	598
April	292	393	320	376	435	418	379	286	337	391	338	359	425	378	325	322	361	300	334	258	318	325	340	321
May	107	156	136	188	148	188	241	44	83	152	110	228	154	166	205	128	157	185	182	112	162	162	163	164
June	15	51	49	35	19	21	12	43	20	63	26	62	39	54	16	28	34	22	50	38	32	35	37	39
July	0	27	0	1	7	2	11	3	4	12	22	5	2	2	3	0	12	0	13	5	5	5	6	5
August	11	34	6	34	9	14	14	8	15	18	5	7	13	30	8	18	20	14	26	15	17	19	16	16
September	152	135	152	100	159	84	121	82	66	138	90	57	60	67	59	121	76	95	107	112	94	91	84	71
October	278	371	342	278	238	314	334	271	322	291	266	370	337	287	270	336	228	322	356	311	303	301	308	308
November	493	507	418	433	612	575	553	453	407	489	410	535	469	484	484	417	517	503	417	492	472	474	473	464
December	801	603	574	696	851	635	755	648	692	883	602	728	722	815	762	610	788	797	759	731	743	752	731	766
Total	4,306	4,739	4,022	4,727	4,585	4,610	4,756	3,825	4,137	4,543	4,115	4,381	4,715	4,637	4,422	4,035	4,453	4,488	4,534	3,979	4,325	4,364	4,376	4,313

Summary of All Cooling Degree Days

Month	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	Model	7 Year Avg	10 Year Avg	20 Year Trend
January	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
February	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
March	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
April	0	0	0	0	0	0	0	0	0	0	0	10	0	2	0	0	0	0	3	2	1	1	2	2
May	34	12	7	9	6	8	0	29	31	3	14	7	0	4	2	17	17	0	3	38	13	13	10	11
June	72	24	30	72	86	52	79	78	100	31	76	40	55	27	112	48	67	61	45	33	60	61	56	55
July	112	24	113	106	126	68	96	89	142	59	78	121	90	87	129	131	65	79	43	151	99	99	97	100
August	101	39	98	40	79	79	41	86	58	60	128	107	106	48	115	68	79	50	82	93	81	81	88	86
September	7	10	11	2	5	34	4	12	50	14	26	51	24	11	33	5	26	25	5	26	20	20	23	27
October	1	0	0	0	1	0	0	0	0	0	0	4	0	0	6	0	2	0	0	0	1	1	1	1
November	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
December	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	327	109	259	229	303	240	220	294	380	166	321	339	275	178	397	269	256	214	181	343	275	277	277	281

The multifactor regression model has determined that the drivers of year-over-year changes in RSL's load growth are population, weather, calendar factors, and monthly peak hours. These factors are captured within the multifactor regression model.

Population – reflects population changes in the RSL service territory from 2004 to 2010.

Weather impacts on load are apparent in both the winter heating season, and in the summer cooling season. For that reason, both Heating Degree Days (i.e. a measure of coldness in winter) and Cooling Degree Days (i.e. a measure of summer heat) are modeled.

Additional factors determining energy use in the monthly model can be classified as calendar factors. For example, the number of days in a particular month will impact energy use. The modeling of purchased energy uses number of days in the month and a "flag" variable to capture the typically lower usage in the spring and fall months.

Monthly peak hours were also used as predictors of usage.

The following historical monthly data were used as inputs in the regression model:

- Monthly total system purchased energy data (adjusted) from January 2004 to December 2010;
- Weather data: heating degree-days (HDD) and cooling degree-days (CDD) (RSL uses the degree-days count for the Ottawa data point as published by Environment Canada);
- Population data obtained from the United Counties website.
- Number of days in the month;
- Number of peak hours (16* number of business days in any given month, excluding weekends and holidays)
- Spring fall flag (1 for Spring and Fall, and 0 for Summer and Winter)

The prediction formula has the following statistical results in Table 3.6, which indicates the formula has a very good fit to the actual data set.

The Chart below provides 2012 weather normal HDD and CDD values, based on the 10 and 20 Year HDD/CDD history.

2012 Billed Energy Forecast (kWh) based on 10 and 20 Year HDD /CDD							
Residential	General Service < 50kW	General Service 50 - 4999 kW	Number of Years	Streetlights	Sentinel Lights	Unmetered Scattered Load	Total
44,721,746	19,867,490	38,216,425	**10**	1,441,722	108,277	429,961	104,785,621
44,606,775	19,816,414	38,174,536	**20**	1,441,722	108,277	429,961	104,577,685

Table 3.6

Statistical Results	
	Value
R Square	97%
Adjusted R Square	97%
F-Test	
T-Stats by Coefficient	
Intercept	-12.16
Heating Degree Days	33.13
Cooling Degree Days	10.64
Population	12.27
Number of Days in Month	5.10
Spring Fall Flag	-4.35
Number of Peak Hours	2.47

The monthly data used in the regression model and the resulting monthly prediction for the actual and forecasted years are provided in Appendix A.

The annual results of the above prediction formula compared to the actual annual purchases from 2004 to 2010 are shown in Table 3.7 below. In addition, the predicted total system purchases for RSL are provided for the years 2011 and 2012. For 2011 and 2012, the system purchases reflect a weather normalized forecast for the full year.

Table 3.7

Actual vs. Predicted Purchases (kWh)

Year	Actual	Predicted	% Difference
2004	127,729,610	129,412,947	1.3%
2005	129,569,190	129,685,280	0.1%
2006	125,693,570	123,972,367	-1.4%
2007	125,561,560	123,976,075	-1.3%
2008	121,334,640	121,661,120	0.3%
2009	118,414,830	119,274,359	0.7%
2010	116,592,701	116,913,953	0.3%
2011		115,241,655	
2012		112,870,798	

Billed kWh Forecast:

To determine the total weather normalized energy billed forecast, the total system weather normalized purchases forecast is adjusted by a loss factor. RSL has applied the Total Loss Factor applied for in this application as detailed in Exhibit 8.

Billed kWh Load Forecast and Customer/Connection Forecast by Rate Class:

Since the total weather normalized billed energy amount is known, this amount needs to be distributed by rate class for rate design purposes taking into consideration the customer/connection forecast and expected usage per customer by rate class.

The next step in the forecasting process is to determine a customer/connection forecast. The customer/connection forecast is based on reviewing historical customer/connection data that is available as shown in Table 3.8.

Table 3.8

Number of Customers/Connections								
Year	Residential	General Service < 50kW	General Service 50 - 4999 kW	Large User	Streetlights	Sentinel Lights	Unmetered Scattered Load	Total
2004	4,869	761	70	0	1,635	56	50	7,441
2005	4,931	770	67	0	1,633	56	49	7,506
2006	4,962	771	65	0	1,641	67	50	7,556
2007	4,967	784	65	0	1,644	67	48	7,575
2008	4,966	778	66	0	1,637	67	49	7,563
2009	4,974	774	66	0	1,640	75	49	7,578
2010	4,982	770	66	0	1,701	75	48	7,642

From the historical customer/connection data the growth rate in customer/connection can be evaluated which is provided in Table 3.9. The geometric mean growth rate in number of customers is also provided. The geometric mean approach provides the average growth rate on a compounding basis.

Table 3.9

Growth Rate in Customers/Connections							
Year	Residential	General Service < 50kW	General Service 50 - 4999 kW	Large User	Streetlights	Sentinel Lights	Unmetered Scattered Load
2004							
2005	1.0127	1.0118	0.9571	0.0000	0.9988	1.0000	0.9800
2006	1.0063	1.0013	0.9701	0.0000	1.0049	1.1964	1.0204
2007	1.0010	1.0169	1.0000	0.0000	1.0018	1.0000	0.9600
2008	0.9998	0.9923	1.0154	0.0000	0.9957	1.0000	1.0208
2009	1.0016	0.9949	1.0000	0.0000	1.0018	1.1194	1.0000
2010	1.0016	0.9948	1.0000	0.0000	1.0372	1.0000	0.9796
2011 Normalized	1.0048	1.0000	0.9970	0.0000	1.0023	0.9935	1.2042
2012 Normalized	1.0021	1.0000	0.9970	0.0000	1.0023	1.0065	0.9959

The resulting geometric mean is applied to the 2010 customer/connection numbers to determine the forecast of customer/connections in 2011 and 2012. The forecast customer number for 2011 and 2012, are shown in Table 3.3.

Ten (10) new Unmetered Scattered Load accounts for a cable company, were added in early 2011, and have been included as a full year for our customer count in 2011.

The next step in the process is to review the historical customer/connection usage and to reflect this usage per customer in the forecast. Table 3.10 provides the average annual usage per customer by rate class from 2004 to 2010.

Table 3.18 provides the forecast customer/connections, and load for 2011 and 2012.

Table 3.10

Annual kWh Usage per Customer/Connection							
Year	Residential	General Service < 50kW	General Service 50 - 4999 kW		Streetlights	Sentinel Lights	Unmetered Scattered Load
2004	9,249	30,729	801,585	-	831	1,717	4,124
2005	9,418	30,507	816,169	-	833	1,694	5,498
2006	8,956	28,820	744,699	-	817	1,528	6,090
2007	9,077	28,521	688,217	-	847	1,536	6,723
2008	8,954	27,146	672,452	-	852	1,495	6,606
2009	8,914	26,356	652,919	-	850	1,447	7,102
2010	8,870	26,518	626,576	-	841	1,444	7,024

As can been seen from Table 3.10 above, usage per customer/connection begins to decline in the Residential class after 2005 with a slight increase in 2007, however, decreases again thereafter. It is RSL's view this decline is partially due to the CDM programs initiated in 2005 and later.

From the historical usage per customer/connection data the growth rate in usage per customer/connection can be reviewed which is provided in Table 3.11. The geometric mean growth rate has also been shown.

However in the case of Unmetered Scattered Load (USL), the Geomean does not accurately reflect anticipated growth in these classes. RSL has made a knowledgeable and educated change to the figure of "1.0312", to a stable 1.0. This is in order to ensure that there are no future increases in this customer class based on our experience with RSL distribution area and RSL striving to ensure that all new distribution connections are metered where possible. It is known that LDC's (including RSL) are steering away from USL customer class with the intent of metering as many connections as possible. RSL has been ensuring that current and future loads will all be attempted to be metered, where possible. This will cause the unmetered classes to decline over time.

Table 3.11

Growth Rate in Usage per Customer / Connection							
Year	**Residential**	**General Service < 50kW**	**General Service 50 - 4999 kW**	**Large User**	**Streetlights**	**Sentinel Lights**	**Unmetered Scattered Load**
2004							
2005	1.0182	0.9928	1.0182	0.0000	1.0017	0.9868	0.0000
2006	0.9510	0.9447	0.9124	0.0000	0.9818	0.9020	0.0000
2007	1.0135	0.9896	0.9242	0.0000	1.0361	1.0053	0.0000
2008	0.9864	0.9518	0.9771	0.0000	1.0056	0.9731	0.0000
2009	0.9955	0.9709	0.9710	0.0000	0.9980	0.9682	1.0752
2010	0.9951	1.0061	0.9597	0.0000	0.9889	0.9974	0.9890
Geometric Mean	0.9931	0.9757	0.9598	0.0000	1.0019	0.9715	1.0312

Conservation and Demand Management Adjustment:

RSL supports the Provincial Government's Conservation and Demand Management ("CDM") initiatives and from 2005 to 2007 delivered CDM programs funded through 3rd tranche revenue and is currently delivering CDM programs that are funded through the Ontario Power Authority ("OPA"). The impact of these historical programs on the load in future years is incorporated in the load forecast presented in this Exhibit, through the modeling process.

On March 31, 2010, the Minister of Energy and Infrastructure issued a Directive to the Ontario Energy Board (the "Board") to establish electricity conservation and demand management targets for each local distribution company ("LDC"). These targets must total 1,330 MW of provincial peak demand and 6,000 GWh of reduced electricity consumption over a four year period starting in 2011. The OEB (EB-2010-0216) issued proposed CDM Targets for each distributor on June 22, 2010 and RSL has been given a proposed CDM Target reduction of 5,100,000 kWh.

In this application RSL has reflected a decrease of 510,000 kWh in 2011 and a total decrease of 1,020,000 kWh in 2012 representing 10% and 20% of its target, respectively.

The CDM adjustments have not been assigned to a specific rate class; it has been applied on a prorated basis by class energy and demand. Table 3.12 details the application of the CDM Adjustment.

The loss factor calculation has excluded 2007 data, because it was an anomaly.

Table 3.12

CDM Adjustment		
	2011	**2012**
Predicted kWh Purchases prior to CDM Adjustment	115,751,655	113,890,798
CDM kWh Target Savings for 2011	510,000	
CDM kWh Target Savings for 2012		1,020,000
Predicted kWh Purchases after CDM Adjustment	115,241,655	112,870,798
Purchases kWh Divided by Total Loss Factor	1.0797	1.0797
kWh to allocate to Rate Classes	106,733,113	104,537,301

The non-normalized weather billed energy forecast has been determined including the CDM Adjustments, however, this needs to be adjusted in order to be aligned with the total weather normalized billed energy forecast.

The difference between non-normalized and normalized forecast is assumed to be the amount related to moving the forecast to a weather normal basis. This difference will be assigned to those rate classes that are weather sensitive. RSL used the weather normalization work completed by Hydro One for RSL for its 2007 Cost Allocation Study as a starting point and has shown its weather sensitivity by rate class below in Table 3.13.

RSL has reviewed previous rate applications and has noted the concern of Intervenors that the Residential and GS <50kW classes are not 100% weather sensitive. RSL has, thus, applied a weather sensitivity factor of 76%, which is the mid-point between the 100% HONI reported for these two classes and the GS 50-4999kW sensitivity factor of 32%. None of the other rate classes were assumed to be weather sensitive.

Table 3.13

Weather Sensitivity						
Residential	General Service < 50kW	General Service 50 - 4999 kW	Large User	Streetlights	Sentinel Lights	Unmetered Scattered Load
76%	76%	32%	0%	0%	0%	0%

As a result, any differences in 2011 and 2012 kWh have been assigned on a prorated basis to each rate classes based on the above level of weather sensitivity. Table 3.14 outlines how the weather sensitive rate classes have been adjusted to align the non-normalized forecast with the normalized forecast.

The 2011 and 2012 Non-Normal weather Billed Energy forecast was developed by multiplying the forecasted numbers of customers/connections times the forecasted usage per customer/connection times the Geomean. As an example, the Non-Normal to Weather Normal Forecast shown in Table 3.14 for GS <50kW is 19,923,344 for 2011 and 19,439,933 for 2012. The GS <50kW calculation is:

- Table 3.3 – Customer count for 2010, 2011, and 2012 - 770
- Table 3.4 – annual kWh Usage per customer for 2010 26,518
- Table 3.11 - Geomean growth rate for GS <50kW .9757

The product of these three numbers, provides the 19,932,344 kWh's for 2011.

A similar calculation is performed for the other customers classes for 2011 and for 2012.

Table 3.14

Allignment of Non-Normal to Weather Normal Forecast

	Non-Normal Weather Billed Energy Forecast (kWh)							
Year	Residential	General Service < 50kW	General Service 50 - 4999 kW	Large User	Streetlights	Sentinel Lights	Unmetered Scattered Load	Total
2011	43,974,933	19,923,344	39,571,474	0	1,435,688	108,277	418,681	105,432,397
2012	43,759,314	19,439,933	37,865,768	0	1,441,722	108,277	429,961	103,044,974

	Adjustment for Weather (kWh)							
Year	Residential	General Service < 50kW	General Service 50 - 4999 kW	Large User	Streetlights	Sentinel Lights	Unmetered Scattered Load	Total
2011	710,016	321,681	269,018	0	0	0	0	1,300,715
2012	825,132	366,562	300,633	0	0	0	0	1,492,327

	Weather Normalized Billed Energy Forecast (kWh)							
Year	Residential	General Service < 50kW	General Service 50 - 4999 kW	Large User	Streetlights	Sentinel Lights	Unmetered Scattered Load	Total
2011	44,684,949	20,245,025	39,840,492	0	1,435,688	108,277	418,681	106,733,113
2012	44,584,446	19,806,495	38,166,401	0	1,441,722	108,277	429,961	104,537,301

Billed kW Load Forecast:

There are three rate classes that charge volumetric distribution on per a kW basis. These include GS 50-4,999 kW, Street Lighting, and Sentinel Lighting. As a result, the energy forecast for these classes needs to be converted to a kW basis for rate setting purposes. The forecast of kW for these three classes is based on an analysis of the average historical ratio of kW to kWh's and applying this ratio to the forecasted kWh to produce the required kW. RSL notes that as the CDM Adjustment was applied to kWh, and kWh is being converted to kW, the kW, thus, already reflects the CDM Adjustment, and RSL has not applied any additional CDM adjustments to its forecasted kW.

Table 3.15 outlines the annual demand units by applicable rate class.

Table 3.15

	Historical Annual kW				
Year	General Service 50 - 4999 kW	Large User	Streetlights	Sentinel Lights	Total
2004	142,556	0	3,752	267	146,575
2005	139,429	0	3,764	261	143,454
2006	133,580	0	3,772	284	137,636
2007	118,636	0	3,777	286	122,699
2008	124,007	0	3,782	278	128,067
2009	130,261	0	3,774	301	134,336
2010	132,433	0	3,857	301	136,591

Table 3.16 shows the trend analysis for the kW/kwh Ratios for RSL's customers that are billed based on demand (kW).

Table 3.16

kW / kWh Ratio				
Year	General Service 50 - 4999 kW	N/A	Streetlights	Sentinel Lights
2004	0.2541%	N/A	0.2761%	0.2777%
2005	0.2550%	N/A	0.2769%	0.2751%
2006	0.2760%	N/A	0.2812%	0.2774%
2007	0.2652%	N/A	0.2713%	0.2779%
2008	0.2794%	N/A	0.2713%	0.2776%
2009	0.3023%	N/A	0.2707%	0.2773%
2010	0.3202%	N/A	0.2698%	0.2780%
2011 Trended	0.3212%	N/A	0.2680%	0.2780%
2012 Trended	0.3318%	N/A	0.2665%	0.2782%

Table 3.17 outlines the kW forecast for the three applicable rate classes.

Table 3.17

Year	General Service 50 - 4999 kW	Large User	Streetlights	Sentinel Lights	Total
2011	127,987	0	3,848	301	132,136
2012	126,652	0	3,843	301	130,796

A summary of the billing determinants by rate class that has been used to develop the proposed rates is provided in Table 3.18.

Table 3.18

RSL Weather Normal Load forecast for 2012 Rate Application

	2004 Actual	2005 Actual	2006 Actual	2007 Actual	2008 Actual	2009 Actual	2010 Actual	2011 Weather Normal	2012 Weather Normal
Actual kWh Purchases	127,729,610	129,569,190	125,693,570	125,561,560	121,334,640	118,414,830	116,592,701		
Predicted kWh Purchases	129,412,947	129,685,280	123,972,367	123,976,075	121,661,120	119,274,359	116,913,953	115,241,655	112,870,798
% Difference	1.3%	0.1%	-1.4%	-1.3%	0.3%	0.7%	0.3%		
Billed kWh	126,191,356	126,336,267	116,814,435	113,998,664	111,785,106	109,680,577	107,839,547	106,733,113	104,537,301
By Class									
Residential									
Customers	4,869	4,931	4,962	4,967	4,966	4,974	4,982	5,006	5,016
kWh	45,034,614	46,438,361	44,440,685	45,086,486	44,465,236	44,337,599	44,191,614	44,684,949	44,584,446
Consumption % Difference		3.02%	-4.50%	1.43%	-1.40%	-0.29%	-0.33%	1.10%	-0.23%
General Service < 50 kW									
Customers	761	770	771	784	778	774	770	770	770
kWh	23,384,526	23,490,754	22,220,025	22,360,087	21,119,955	20,399,815	20,418,777	20,245,025	19,806,495
Consumption % Difference		0.45%	-5.72%	0.63%	-5.87%	-3.53%	0.09%	-0.86%	-2.21%
General Service > 50 kW									
Customers	70	67	65	65	66	66	66	66	66
kWh	56,110,937	54,683,320	48,405,425	44,734,117	44,381,852	43,092,665	41,354,016	39,840,492	38,166,401
kW	142,556	139,429	133,580	118,636	124,007	130,261	132,433	127,987	126,652
Consumption % Difference		-2.61%	-12.97%	-8.21%	-0.79%	-2.99%	-4.20%	-3.80%	-4.39%
Street Lights									
Customers	1,635	1,633	1,641	1,644	1,637	1,640	1,701	1,705	1,709
kWh	1,358,901	1,359,556	1,341,413	1,392,325	1,394,217	1,393,923	1,429,699	1,435,688	1,441,722
kW	3,752	3,764	3,772	3,777	3,782	3,774	3,857	3,848	3,843
Consumption % Difference		0.05%	-1.35%	3.66%	0.14%	-0.02%	2.50%	0.42%	0.42%
Sentinel Lights									
Connections	56	56	67	67	67	75	75	75	75
kWh	96,156	94,884	102,394	102,933	100,161	108,556	108,277	108,277	108,277
kW	267	261	284	286	278	301	301	301	301
Consumption % Difference		-1.34%	7.33%	0.52%	-2.77%	7.73%	-0.26%	0.00%	0.00%
Unmetered Loads									
Connections	50	49	50	48	49	49	48	58	58
kWh	206,222	269,392	304,493	322,716	323,685	348,019	337,164	418,681	429,961
Consumption % Difference		23.45%	11.53%	5.65%	0.30%	6.99%	-3.22%	19.47%	2.62%
Total									
Customer/Connections	7,441	7,506	7,556	7,575	7,563	7,578	7,642	7,679	7,693
kWh	126,191,356	126,336,267	116,814,435	113,998,664	111,785,106	109,680,577	107,839,547	106,733,113	104,537,301
kW from applicable classes	146,575	143,454	137,636	122,699	128,067	134,336	136,591	132,136	130,796

3.0 OPERATING REVENUE VARIANCE ANALYSIS

Operating Revenue and Other Operating Revenue

Operating Revenue:

Operating revenues in this application includes fixed charges revenue from monthly charges, multiplied by the number of customers forecast in the year (for Bridge and Test Years).

2011 Operating Revenues:

RSL's Operating Revenue for the 2011 Bridge Year has been calculated using its most recently approved rates and estimated number of customers and consumption.

Table 3.19

Forecast Class Billing Determinants for 2011 Bridge Year Based on Existing Class Revenue Proportions

Revenue At Existing Rates

Class	Annual kWh	Annual kW For Dx	Annualized Customers	Annualized Connections	Fixed Distribution Revenue	Variable Distribution Revenue	Dist. Rev. Including Transformer	Transformer Allowance	Dist. Rev. Excluding Transformer	Dist Rev At Existing Rates %
Residential	44,684,949		60,072		617,540	522,814	1,140,354		1,140,354	58.10%
GS < 50 kW	20,245,025		9,240		224,902	149,813	374,715		374,715	19.09%
GS 50 - 4,999 kW	39,840,492	127,987	790		222,192	159,638	381,830	37,745	344,085	17.53%
0								0		0.00%
Sentinel Lights	108,277	301		894	1,109	2,731	3,839		3,839	0.20%
Street Lighting	1,435,688	3,848		20,459	46,852	33,627	80,479		80,479	4.10%
USL	418,681	694			5,140	14,235	19,375		19,375	0.99%
0		0			0	0	0		0	0.00%
0	0	0	0		0	0	0		0	0.00%
	106,733,113	**132,829**	**70,102**	**21,353**	**1,117,734**	**882,858**	**2,000,591**	**37,745**	**1,962,847**	**100%**

2012 Operating Revenues:

RSL's Operating Revenues at existing rates for the 2012 Test Year have been calculated using the most recently approved rates and forecast number of customers and consumption, as shown in Table 3.20.

Table 3.20

Forecast Class Billing Determinants for 2012 Test Year Based on Existing Class Revenue Proportions

Revenue At Existing Rates

Class	Annual kWh	Annual kW For Dx	Annualized Customers	Annualized Connections	Fixed Distribution Revenue	Variable Distribution Revenue	Dist. Rev. Including Transformer	Transformer Allowance	Dist. Rev. Excluding Transformer	Dist Rev At Existing Rates %
Residential	44,584,446		60,196		618,812	521,638	1,140,450		1,140,450	58.25%
GS < 50 kW	19,806,495		9,240		224,902	146,568	371,470		371,470	18.97%
GS 50 - 4,999 kW	38,166,401	126,652	787		221,524	157,973	379,497	37,745	341,752	17.46%
0	0	0	0		0	0	0	0	0	0.00%
Sentinel Lights	108,277	301		900	1,116	2,731	3,846		3,846	0.20%
Street Lighting	1,441,722	3,843		20,507	46,961	33,583	80,544		80,544	4.11%
USL	429,961		691		5,119	14,619	19,737		19,737	1.01%
0		0			0	0	0		0	0.00%
0	0	0	0		0	0	0		0	0.00%
	104,537,301	130,796	70,914	21,407	1,118,434	877,111	1,995,545	37,745	1,957,800	100%

In Table 3.21 below, we demonstrate the Operating Revenues at new rates for the 2012 Test Year that were calculated during rate design taking into account the revenue deficiency, using forecasted number of customers/connections and consumption

Table 3.21

Distribution Rate Allocation Between Fixed & Variable Rates For 2012 Test Year

Customer Class	Total Net Rev. Requirement	Revenue Requirement %	Proposed Fixed Rate	Resulting Variable Rate	Total Fixed Revenue	Total Variable Revenue	Transformer Allowance	Gross Distribution Revenue	LV & Wheeling Charges	Total
Residential	1,453,328	57.49%	13.10	$0.0149	$ 788,581	$ 664,747		1,453,328	74,620	1,527,948
GS < 50 kW	479,683	18.97%	31.43	$0.0096	$ 290,418	$ 189,265		479,683	30,889	510,572
GS 50 - 4,999 kW	460,657	18.22%	379.29	$1.5776	$ 298,598	$ 162,058	$ 37,745	498,402	72,979	571,380
0	0	0.00%		#DIV/0!	$ -	$ -	$ -	0	0	0
Sentinel Lights	4,967	0.20%	1.60	$11.7143	$ 1,441	$ 3,526		4,967	137	5,104
Street Lighting	104,007	4.11%	2.96	$11.2852	$ 60,641	$ 43,367		104,007	1,712	105,719
USL	25,487	1.01%	9.57	$0.0439	$ 6,610	$ 18,877		25,487	671	26,158
0	0	0.00%		#DIV/0!	$ -	$ -		0	0	0
0	0	0.00%		#DIV/0!	$ -	$ -		0	0	0
TOTAL	2,528,129	100%			$ 1,446,289	$ 1,081,840	$ 37,745	$ 2,565,874	$ 181,008	$ 2,746,881
			Forecast Fixed/Variable Ratios		56.366%	42.163%	1.471%	100.000%		

Overall RSL has had both load increases and load decreases from 2006 to the 2012 forecast year, depending on the customer class. The largest change was from the bankruptcy of an Industrial manufacturing customer in early 2006. The facility sat idle for a while, then was turned into a warehouse and processing facility, reducing the Industrial consumption and demand. This loss of Demand and kWh's was built into the 2008 Cost of Service Rate Application (EB-2007-0762), but the volumes were included in the Industrial history for 2004, 2005, and part of 2006. An adjustment was made to reduce the history for this account to current levels, and to match the volume levels that were approved by the Board in EB-2007-0762, and to match the last three years average consumption.

Other decreases in load can be attributed to the success of conservation initiatives undertaken by RSL Customers. Increases' can be attributed to limited growth in RSL's service territory, and weather factors. See Table 3.3 and 3.4 of this exhibit.

Information related to RSL's Operating revenue includes details such as weather normalized forecasting methodology, normalized volume based on historical number of customers billed throughout the year and CDM adjustments and known economic conditions.

A detailed variance analysis on the Operating revenue is set out later in this Exhibit.

4.0 OTHER REVENUE

Other revenues include Standard Service Supply (SSS) Administration Charges, Late Payment Charges, Miscellaneous Service Revenues, Rent from Electric Property, Service Transaction Requests, Retail Service Revenues and Interest and Dividend Income. The fall in bank interest rates had a significant impact on other revenue as interest income declined.

Variance Analysis on Other Distribution Revenue:

A summary of historical and forecast operating revenues is presented in Table 3.1. RSL's distribution revenue has been calculated using its most recently approved rates. In particular, delivery rates are based on the EB-2010-0113 Decision and Order dated April 28, 2011. Operating revenue does not include commodity-related revenue.

2008 Board Approved vs. 2008 Actual:

RSL's Total 2008 Board Approved operating revenue was forecast to be $2,223,540 . Distribution Revenue was $1,971,690, with Revenue Offsets of $251,850.

2008 Actual Revenue was $198,828 under the Board Approved amount, mainly because the board Approved amount was for a calendar year, while the actual 2008 rates were effective June 13, 2008 – allowing only a little over a half year of revenue at the new rates.

2008 Actual vs. 2009 Actual:

2009 Actual is $185,894 higher than 2008 actual, mainly because the 2009 Fiscal year, included 12 full months at the 2008 approved rate levels. Operating Income for 2009 is $12,934 lower than a full year of revenue at the 2008 Board Rate Approved level.

Table 3.22 below highlights the revenue swing due to the June 13, 2008 effective date for Board approved rates, and with a full year in 2009 at the 2008 approved rates, RSL's actual revenue matches the approved levels. 2009 Actual Revenues, with a full year of 2008 OEB approved Rates, are almost the same – 2008 Board Approved of $2,223,540, vs. 2009 Actual of $2,210,606.

2010 Actual vs. 2009 Actual:

2010 actuals, at $2,223,656, are $13,050 higher than 2009 actuals, and $116 higher than the total approved by the Board for the 2008 Rate year. Very little net change was made to rates as a result of the 2009 and the 2010 IRM rate approvals.

Table 3.22

Variance Analysis on Actual Operating Revenue

Summary	2008 Board Approved $	2008 Actual $	2008 Board Approved $	2009 Actual $	from 2008 Actual $	2010 Actual $	from 2009 Actual $
Distribution Revenue							
Residential	1,123,163	1,040,276	-82,887	1,156,502	116,226	1,147,032	-9,470
GS< 50 kW	394,398	300,610	-93,788	375,059	74,449	378,223	3,164
GS> 50 kW	374,934	337,523	-37,411	354,195	16,672	346,031	-8,163
Street Light	62,039	57,337	-4,702	77,353	20,016	85,309	7,957
Sentinel Light	2,958	2,855	-103	4,063	1,208	4,070	7
Unmetered Scattered Load	14,198	15,184	986	16,617	1,432	15,968	-649
Total	1,971,690	1,753,785	-217,905	1,983,789	230,004	1,976,634	-7,155
Other Distribution Revenue							
Specific Service Charges	94,264	119,859	25,595	102,692	-17,167	104,819	2,127
Late Payment Charges	52,700	47,320	-5,380	52,703	5,383	44,526	-8,177
Other Distribution Revenue	73,886	77,166	3,280	66,905	-10,261	89,659	22,754
Other Income & Expenses	31,000	26,583	-4,417	4,517	-22,066	8,019	3,502
Total	251,850	270,927	19,077	226,817	-44,110	247,022	20,205
Grand Total	2,223,540	2,024,712	-198,828	2,210,606	185,894	2,223,656	13,050

2011 Bridge vs. 2010 Actual – Reference Table 3.23:

2011 Bridge Operating Revenue is down slightly to $2,190,500, from 2010 actual of $2,223,656, due to conservation programs, and changes to the customer service rules that will reduce RSL Other Distribution Revenue.

On October 1, 2010 the OEB issued a letter outlining Province wide requirement for an arrears payment agreement being made to residential customers, and provided a link to future customer service rules to take effect January 1, 2011 or April 1, 2011. On November 30th and December 1st, 2011, the OEB conducted webinars on customer service rule changes for eligible low-income electricity customers that came into effect October 1, 2011.

The changes to Distribution system Code (DSC), the Retail Settlement Code (RSC), and the Standard Supply Service Code (SSSC) came into effect over 2010, and 2011, so the full impact will not be felt by the LDC's until 2012.

The arrears payment agreements require customer deposits to be returned to them, and late payment charges cannot be assessed while the customer is funder the plan.

2012 Test vs. 2011 Bridge – Reference Table 3.23:

RSL's Test Year Operating Income is $2,736,959, or $546,459 higher than the 2011 Bridge year.

The variance is due to the use of the proposed rates to recover the Revenue Deficiency of $ 570,329. The Revenue Deficiency is attributable to the addition of Smart meter of $1,294,090 to our rate base, and increased OM&A costs. In addition, OPA CDM programs have resulted in reduced consumption to spread increased costs over – resulting in higher rates. The balance of the financial impact of changes to the customer service rules, for LEAP, and for Low Income, will result in lower revenue offsets in 2012, and increased bad debts.

RSL will have fewer deposits to apply to bad debts, as the updated rules either require us to refund the deposit, or in the case of low income customers, we cannot collect a deposit. A review of our 2009 bad debts, showed that deposits of had been applied against the bad debt. That means that without the deposit the bad debt expense would have been $16,750 higher.

Table 3.23

Variance Analysis – 2010 Actual vs. Bridge and Test Years

Summary	2010 Actual	2011 Bridge	Variance from 2010 Actual	2012 Test	Variance from 2011 Bridge
	$	$	$	$	$
Distribution Revenue					
Residential	1,147,032	1,140,354	-6,678	1,453,328	312,974
GS< 50 kW	378,223	379,379	1,156	479,683	100,304
GS> 50 kW	346,031	346,282	251	460,657	114,375
Street Light	85,309	80,479	-4,830	104,007	23,528
Sentinel Light	4,070	3,839	-231	4,967	1,128
Unmetered Scattered Load	15,968	19,375	3,407	25,487	6,112
Total	1,976,634	1,969,708	-6,926	2,551,634	563,824
Other Distribution Revenue					
Specific Service Charges	104,819	93,160	-11,659	88,900	-4,260
Late Payment Charges	44,526	34,093	-10,433	32,400	-1,693
Other Distribution Revenue	89,659	74,975	-14,684	74,243	-732
Other Income & Expenses	8,019	12,000	3,981	12,000	0
Total	247,022	214,228	-32,794	207,543	-6,685
Grand Total	2,223,656	2,183,936	-39,720	2,735,672	551,736

Other Distribution Revenue:

A summary of Other Distribution Revenue (Appendix 2-C of the Filing Requirements is shown in Table 3.24.

Table 3.24

Other Distribution Revenue

USoA #	USoA Description	OEB aproved 08	Actual 2008	Actual 2009	Actual 2010	Bridge Year	Test Year
4235	**Specific Service C**	**-$94,264**	-$119,859	-$102,692	-$104,819	-$93,160	-$88,900
4225	**Late Payment Cha**	**-$52,700**	-$47,320	-$52,703	-$44,526	-$34,093	-$32,400
4080	**SSS Admin**	**-$22,647**	-$20,476	-$20,746	-$20,323	-$20,623	-$21,528
4082	**Retail Services Re**	**-$7,000**	-$9,408	-$8,766	-$10,066	-$9,501	-$8,550
4084	STR Revenues - EB	-$634	-$258	-$158	-$248	-$151	-$136
4210	Rent from Electric P	-$43,605	-$47,024	-$37,235	-$59,022	-$44,700	-$44,029
4405	Interest & Dividend	-$31,000	-$26,583	-$4,517	-$8,019	-$12,000	-$12,000
	Total	-$251,850	-$270,927	-$226,817	-$247,022	-$214,228	-$207,543
Specific Service Charges		**-$94,264**	**-$119,859**	**-$102,692**	**-$104,819**	**-$93,160**	**-$88,900**
Late Payment Charges		**-$52,700**	**-$47,320**	**-$52,703**	**-$44,526**	**-$34,093**	**-$32,400**
Other Operating Revenues		**-$73,886**	**-$77,166**	**-$66,905**	**-$89,659**	**-$74,975**	**-$74,243**
Other Income or Deductions		**-$31,000**	**-$26,583**	**-$4,517**	**-$8,019**	**-$12,000**	**-$12,000**
Total		-$251,850	-$270,927	-$226,817	-$247,022	**-$214,228**	**-$207,543**

Specific Service Charges

Variances from Board Approved amount:

Listed below in Table 3.25 are the Specific Service Charges by type for the 2008 Board Approved up to and including the 2012 Test Year values.

There are only two specific service charges that have any significant change from the 2008 Board Approved amount that are discussed below.

Account 4225 Late Payment Charges:

With the changes to the Customer Service Code Amendments for Arrears Management, and Low-Income Code Provisions coming into effect starting in October 2010, and with the latest changes coming into effect October 1, 2011, RSL's income from late payment charges will decline.

With the new rules in place, our ability to charge for late payment is reduced. For those customers who enter into an arrears management agreement, or who become designated as low-income, we cannot assess a late payment charge.

Account 4405 Interest and Dividend Income:

The balances in this account are from bank interest. The interest rates paid by the banks over the past few years, are a lot lower than was envisioned in 2007 when our 2008 rate application was submitted. We expect similar low interest rates to be paid on deposits for 2012, and our forecast is based on recent historical rates.

Table 3.25

Other Distribution Revenue Detail

Account 4235 - Specific Service Charges

	OEB aproved 08	Actual 2008	Actual 2009	Actual 2010	Bridge Year	Test Year
Collection charge	-$ 64,710	-$ 83,482	-$ 72,887	-$ 74,224	-$ 63,900	-$ 60,700
Returned Cheque Charge (NSF)	-$ 1,124	-$ 1,102	-$ 1,215	-$ 1,305	-$ 1,500	-$ 1,200
Occupancy charge	-$ 21,930	-$ 29,475	-$ 24,060	-$ 23,910	-$ 23,640	-$ 24,000
Disconnect/Reconnect Charge	-$ 6,500	-$ 5,800	-$ 4,530	-$ 5,380	-$ 4,120	-$ 3,000
Total	-$ 94,264	-$ 119,859	-$ 102,692	-$ 104,819	-$ 93,160	-$ 88,900

Account 4225 - Late Payment Charges

	OEB aproved 08	Actual 2008	Actual 2009	Actual 2010	Bridge Year	Test Year
Late Payment Charges	-$ 52,700	-$ 47,320	-$ 52,703	-$ 44,526	-$ 34,093	-$ 32,400
Total	-$ 52,700	-$ 47,320	-$ 52,703	-$ 44,526	-$ 34,093	-$ 32,400

Account 4080 - SSS Admin Charges

	OEB aproved 08	Actual 2008	Actual 2009	Actual 2010	Bridge Year	Test Year
SSS Admin (.25 x 12 x Non Rtlr /	-$ 22,647	-$ 20,476	-$ 20,746	-$ 20,323	-$ 20,623	-$ 21,528
Total	-$ 22,647	-$ 20,476	-$ 20,746	-$ 20,323	-$ 20,623	-$ 21,528

Account 4082 - Retail Services Revenue

	OEB aproved 08	Actual 2008	Actual 2009	Actual 2010	Bridge Year	Test Year
Misc Bill Ready Charges (BRC)	-$ 2,000	-$ 2,015	-$ 2,039	-$ 2,297	-$ 1,948	-$ 1,750
Fixed Charges	-$ 2,000	-$ 2,960	-$ 2,700	-$ 3,800	-$ 3,300	-$ 3,000
Variable charges	-$ 3,000	-$ 4,433	-$ 4,027	-$ 3,969	-$ 4,253	-$ 3,800
Total	-$ 7,000	-$ 9,408	-$ 8,766	-$ 10,066	-$ 9,501	-$ 8,550

Account 4084 - STR Revenues - EBT's

	OEB aproved 08	Actual 2008	Actual 2009	Actual 2010	Bridge Year	Test Year
STR Processed	-$ 200	-$ 62	-$ 60	-$ 67	-$ 40	-$ 36
STR Request	-$ 434	-$ 196	-$ 98	-$ 181	-$ 111	-$ 100
Total	-$ 634	-$ 258	-$ 158	-$ 248	-$ 151	-$ 136

Account 4210 - Rent from Electrical Property

	OEB aproved 08	Actual 2008	Actual 2009	Actual 2010	Bridge Year	Test Year
Joint Use - Bell Canada	-$ 17,635	-$ 17,791	-$ 17,791	-$ 29,234	-$ 17,791	-$ 17,791
Joint Use - WTC Communication	-$ 3,643	-$ 4,581	-$ 380	-$ 7,461	-$ 3,643	-$ 3,643
Joint Use - Cable Companies	-$ 22,327	-$ 24,652	-$ 19,065	-$ 22,327	-$ 23,266	-$ 22,595
Total	-$ 43,605	-$ 47,024	-$ 37,235	-$ 59,022	-$ 44,700	-$ 44,029

Account 4405 - Interest and Dividend Income

	OEB aproved 08	Actual 2008	Actual 2009	Actual 2010	Bridge Year	Test Year
Short-term Investment Interest			-$ 921			
Bank Deposit Interest	-$ 31,000	-$ 26,583	-$ 3,596	-$ 8,019	-$ 12,000	-$ 12,000
Miscellaneous Interest Revenue						
etc.[1]						
Total	-$ 31,000	-$ 26,583	-$ 4,517	-$ 8,019	-$ 12,000	-$ 12,000

Variance Analysis on Other Distribution Revenue:

Table 3.26 below shows the number of occurrences by type of specific service charges by year.

In 2008, RSL increased its collection effort, and customer disconnections, in order to reduce future potential bad debts.

In 2010 and 2011 additional changes to the Customer Service Codes for arrears management and for low income customers, have further reduced RSL's potential revenue to be generated for Low-Income customers, and for those customers that enter into an Arrears Management Program.

The access to poles charge was low in 2009 because of a dispute for charges from 2006. In late 2009, RSL discovered that an Invoice from 2006 may not have been sent to the customer, although we had recorded it as revenue, and initially the customer was refusing to pay. In 2009 RSL reduced our Joint Use rental fee to cover this (we had been trying to clear this up for over a year), while continuing discussions. In 2010 the issue was resolved, and the customer made the payment. The result was recognition of double the revenue in 2010.

Table 3.26

Specific Service Charges

			Number of Occurances						
			2008						
			Board	2008	2009	2010	2011	2012	Test Year
Customer Administration	Metric	Rate $	Approved	Actual	Actual	Actual	Bridge	Test	Revenue
Arrears certificate	$	15.00							
Statement of account	$	15.00							
Pulling post dated cheques	$	15.00							
Duplicate invoices for previous billing	$	15.00							
Request for other billing information	$	15.00							
Easement letter	$	15.00							
Income tax letter	$	15.00							
Notification charge	$	15.00							
Account history	$	15.00							
Credit reference/credit check (plus credit agency costs)	$	15.00							
Returned cheque charge (plus bank charges)	$	15.00	75	74	81	87	100	80	$1,200
Charge to certify cheque	$	15.00							
Legal letter charge	$	15.00							
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	30.00	731	983	802	797	788	800	$24,000
Meter dispute charge plus Measurement Canada fees (if meter found correct)	$	30.00							
Special meter reads	$	30.00							
Non-Payment of Account	Metric	Current							
Late Payment - per month	%	1.50							
Late Payment - per annum	%	19.56							
Collection of account charge - no disconnection	$	30.00	2,157	2,783	2,430	2,474	2,130	2,023	$60,700
Collection of account charge - no disconnection - after regular hours	$	165.00							
Disconnect/Reconnect at meter - during regular hours	$	65.00	100	89	70	83	63	46	$3,000
Disconnect/Reconnect at meter - after regular hours	$	185.00							
Disconnect/Reconnect at pole - during regular hours	$	185.00							
Disconnect/Reconnect at pole - after regular hours	$	415.00							
	$								
Other	Metric	Current							
Service call - customer-owned equipment	$	30.00							
Service call - after regular hours	$	165.00							
Install/Remove load control device - during regular hours	$	65.00							
Install/Remove load control device - after regular hours	$	185.00							
Temporary service install & remove - overhead - no transformer	$	500.00							
Temporary service install & remove - underground - no transformer	$	300.00							
Temporary service install & remove - overhead - with transformer	$	1000.00							
Specific Charge for Access to the Power Poles $/pole/year	$	22.35	1,963	2,104	1,666	2,640	2,000	1,970	$44,029

RSL does not propose to add any new Specific Service Charges, from those already approved by the Board in EB-2010-0113, and listed above.

APPENDIX 3A Monthly Data Used for Regression Analysis

	Purchased including Losses	Heating Degree Days	Cooling Degree Days	Population	Number of Days in Month	Spring Fall Flag	Number of Peak Hours	Predicted Purchases	Variances (kWh)
Jan-04	14,251,480	1045.3	0.0	11898.06	31	0	336	14,029,090	-222,390
Feb-04	12,137,260	750.0	0.0	11897.60	29	0	320	12,150,407	13,147
Mar-04	11,409,650	559.2	0.0	11897.14	31	1	368	11,424,000	14,350
Apr-04	9,866,860	377.8	1.9	11896.68	30	1	336	10,267,936	401,076
May-04	9,132,730	166.2	4.0	11896.22	31	1	320	9,390,953	258,223
Jun-04	9,143,830	54.0	27.1	11895.76	30	0	352	9,420,206	276,376
Jul-04	9,810,430	1.8	86.5	11895.30	31	0	336	10,211,620	401,190
Aug-04	9,785,570	29.8	47.5	11894.84	31	0	336	9,737,749	-47,821
Sep-04	9,271,960	66.8	11.1	11894.38	30	1	336	8,848,906	-423,054
Oct-04	9,611,500	287.0	0.0	11893.92	31	1	320	9,881,853	270,353
Nov-04	10,514,990	484.3	0.0	11893.46	30	1	352	10,756,709	241,719
Dec-04	12,793,350	814.9	0.0	11893.00	31	0	336	12,815,976	22,626
Jan-05	13,599,460	920.7	0.0	11892.30	31	0	320	13,269,637	-329,823
Feb-05	11,597,730	700.6	0.0	11891.60	28	0	320	11,620,063	22,333
Mar-05	11,805,830	668.8	0.0	11890.90	31	1	352	11,803,123	-2,707
Apr-05	9,698,980	324.8	0.0	11890.20	30	1	336	9,870,113	171,133
May-05	9,203,640	205.0	1.9	11889.50	31	1	336	9,488,024	284,384
Jun-05	10,190,860	16.1	111.6	11888.80	30	0	352	10,424,619	233,759
Jul-05	10,516,530	2.9	128.6	11888.10	31	0	320	10,694,560	178,030
Aug-05	10,498,410	8.4	115.4	11887.40	31	0	352	10,608,298	109,888
Sep-05	9,504,880	59.2	33.1	11886.70	30	1	336	9,022,856	-482,024
Oct-05	9,922,960	269.7	6.4	11886.00	31	1	320	9,762,986	-159,974
Nov-05	10,652,470	484.2	0.0	11885.30	30	1	352	10,619,028	-33,442
Dec-05	12,377,440	762.0	0.0	11884.60	31	0	320	12,363,182	-14,258
Jan-06	12,508,470	733.5	0.0	11883.90	31	0	336	12,264,445	-244,025
Feb-06	11,727,560	720.9	0.0	11883.20	28	0	320	11,578,225	-149,335
Mar-06	11,784,150	600.4	0.0	11882.50	31	1	368	11,379,577	-404,573
Apr-06	9,406,440	321.6	0.0	11881.80	30	1	304	9,609,161	202,721
May-06	9,293,920	128.2	16.9	11881.10	31	1	352	9,252,971	-40,949
Jun-06	9,564,320	27.6	48.2	11880.40	30	0	352	9,359,068	-205,252
Jul-06	10,639,870	0.3	130.6	11879.70	31	0	320	10,571,538	-68,332
Aug-06	10,096,480	18.2	68.1	11879.00	31	0	352	9,783,448	-313,032
Sep-06	8,938,560	121.0	5.3	11878.30	30	1	320	8,701,026	-237,534
Oct-06	9,952,100	335.7	0.0	11877.60	31	1	336	9,898,473	-53,627
Nov-06	10,436,420	417.3	0.0	11876.90	30	1	352	10,150,258	-286,162
Dec-06	11,345,280	610.0	0.0	11876.20	31	0	304	11,427,582	82,302
Jan-07	12,568,180	797.1	0.0	11875.50	31	0	352	12,484,784	-83,396
Feb-07	12,210,720	820.0	0.0	11874.80	28	0	320	11,922,193	-288,527
Mar-07	11,873,120	643.0	0.0	11874.10	31	1	352	11,394,352	-478,768
Apr-07	9,854,780	361.1	0.0	11873.40	30	1	320	9,712,200	-142,580
May-07	9,000,430	157.3	17.3	11872.70	31	1	352	9,260,405	259,975
Jun-07	9,265,780	34.2	66.9	11872.00	30	0	336	9,488,521	222,741
Jul-07	9,662,330	11.8	65.1	11871.30	31	0	336	9,526,074	-136,256
Aug-07	9,982,760	20.1	79.3	11870.60	31	0	352	9,824,757	-158,003
Sep-07	9,063,690	76.0	25.7	11869.90	30	1	304	8,604,139	-459,551
Oct-07	9,402,850	227.5	1.9	11869.20	31	1	352	9,307,064	-95,786
Nov-07	10,423,660	517.0	0.0	11868.50	30	1	352	10,497,163	73,503
Dec-07	12,253,260	787.7	0.0	11867.80	31	0	304	12,156,377	-96,883

Appendix 3A **Monthly Data Used for Regression Analysis**

	Purchased including Losses	Heating Degree Days	Cooling Degree Days	Population	Number of Days in Month	Spring Fall Flag	Number of Peak Hours	Predicted Purchases	Variances (kWh)
Jan-08	12,288,190	754.2	0.0	11867.10	31	0	352	12,133,800	-154,390
Feb-08	11,701,800	774.3	0.0	11866.40	29	0	320	11,744,309	42,509
Mar-08	11,663,590	721.1	0.0	11865.70	31	1	304	11,481,627	-181,963
Apr-08	9,464,610	299.6	0.0	11865.00	30	1	352	9,373,668	-90,942
May-08	8,709,540	185.4	0.0	11864.30	31	1	336	8,938,068	228,528
Jun-08	9,032,720	22.4	60.5	11863.60	30	0	336	9,189,760	157,040
Jul-08	9,681,910	0.3	78.9	11862.90	31	0	352	9,592,454	-89,456
Aug-08	9,241,240	14.4	49.5	11862.20	31	0	320	9,092,207	-149,033
Sep-08	8,800,520	95.4	25.0	11861.50	30	1	336	8,650,354	-150,166
Oct-08	8,997,790	321.8	0.0	11860.80	31	1	352	9,598,426	600,636
Nov-08	9,775,270	502.8	0.0	11860.10	30	1	304	10,131,997	356,727
Dec-08	11,977,460	796.7	0.0	11859.40	31	0	336	12,161,036	183,576
Jan-09	12,715,660	979.5	0.0	11858.70	31	0	336	13,044,259	328,599
Feb-09	10,806,911	711.5	0.0	11858.00	28	0	304	11,057,546	250,635
Mar-09	10,822,297	598.3	0.0	11857.30	31	1	352	10,893,329	71,032
Apr-09	9,188,119	334.3	2.5	11856.60	30	1	320	9,338,229	150,110
May-09	8,646,669	181.6	3.2	11855.90	31	1	320	8,776,345	129,676
Jun-09	8,694,745	50.4	44.9	11855.20	30	0	352	8,995,718	300,973
Jul-09	8,965,453	13.1	42.9	11854.50	31	0	352	8,957,072	-8,381
Aug-09	9,534,995	26.1	82.1	11853.80	31	0	320	9,512,497	-22,498
Sep-09	8,543,544	106.5	5.0	11853.10	30	1	336	8,254,127	-289,417
Oct-09	9,341,679	355.5	0.0	11852.40	31	1	336	9,570,808	229,129
Nov-09	9,542,500	417.4	0.0	11851.70	30	1	320	9,624,037	81,537
Dec-09	11,612,258	759.4	0.0	11850.00	31	0	352	11,871,762	259,504
Jan-10	12,078,338	789.2	0.0	11849.30	31	0	320	11,903,121	-175,217
Feb-10	10,494,800	655.8	0.0	11848.60	28	0	304	10,626,799	131,999
Mar-10	10,154,062	460.7	0.0	11847.90	31	1	368	10,112,985	-41,077
Apr-10	8,300,785	258.1	1.6	11847.20	30	1	320	8,793,192	492,407
May-10	8,510,046	112.3	38.2	11846.50	31	1	320	8,820,368	310,322
Jun-10	8,680,146	37.6	33.4	11845.80	30	0	352	8,597,135	-83,011
Jul-10	9,983,854	4.5	150.8	11845.10	31	0	336	10,374,464	390,610
Aug-10	9,543,754	14.7	93.0	11844.40	31	0	336	9,518,623	-25,131
Sep-10	8,579,877	112.0	26.2	11843.70	30	1	336	8,450,922	-128,955
Oct-10	8,994,685	311.0	0.0	11843.00	31	1	320	9,143,510	148,825
Nov-10	9,833,800	491.6	0.0	11842.30	30	1	336	9,880,668	46,868
Dec-10	11,438,554	731.4	0.0	11841.60	31	0	368	11,644,833	206,279

Appendix 3A **Monthly Data Used for Regression Analysis**

	Purchased including Losses	Heating Degree Days	Cooling Degree Days	Population	Number of Days in Month	Spring Fall Flag	Number of Peak Hours	Predicted Purchases	Variances (kWh)
Jan-11		859.9	0.0	11,841	31	0	352	12,160,291	27,706
Feb-11		733.3	0.0	11,840	28	0	320	10,857,950	-8,504
Mar-11		607.4	0.0	11,840	31	1	352	10,563,031	-504,577
Apr-11		325.3	0.9	11,839	30	1	320	8,872,097	-200,318
May-11		162.3	11.6	11,838	31	1	352	8,529,314	-126,963
Jun-11		34.6	56.1	11,837	30	0	336	8,641,610	-134,482
Jul-11		5.0	97.6	11,837	31	0	336	9,280,789	-717,403
Aug-11		18.8	76.4	11,836	31	0	352	9,082,507	-368,147
Sep-11		91.0	18.8	11,835	30	1	304	7,860,716	-771,207
Oct-11		301.2	1.2	11,835	31	1	352	8,987,796	66,281
Nov-11		473.5	0.0	11,834	30	1	352	9,621,433	142,718
Dec-11		751.7	0.0	11,833	31	0	304	11,294,121	
Jan-12		859.9	0.0	11,833	31	0	352	12,001,134	
Feb-12		733.3	0.0	11,832	29	0	320	10,879,273	
Mar-12		607.4	0.0	11,831	31	1	304	10,212,391	
Apr-12		325.3	0.9	11,830	30	1	352	8,841,521	
May-12		162.3	11.6	11,830	31	1	336	8,306,330	
Jun-12		34.6	56.1	11,829	30	0	336	8,481,145	
Jul-12		5.0	97.6	11,828	31	0	352	9,183,960	
Aug-12		18.8	76.4	11,828	31	0	320	8,795,694	
Sep-12		91.0	18.8	11,827	30	1	336	7,829,501	
Oct-12		301.2	1.2	11,826	31	1	352	8,828,639	
Nov-12		473.5	0.0	11,826	30	1	304	9,270,122	
Dec-12		751.7	0.0	11,825	31	0	336	11,261,088	

<u>Exhibit 4</u> <u>Operating Costs</u>

Schedule **Contents of Schedule**

1.0 MANAGER'S SUMMARY

OVERVIEW OF OPERATING COSTS

Operating Costs:

The OM&A costs in this application represent Rideau St. Lawrence Distribution Inc.'s (RSL) integrated set of asset maintenance and customer activity needs to meet public and employee safety objectives, to comply with the Distribution System Code, environmental requirements and Government direction, and to maintain distribution business service quality and reliability levels. These costs represent the reasonably incurred cost to provide services to customers connected to Rideau St. Lawrence Distribution Inc.'s distribution system, and to meet the service levels stipulated in the Standard Supply Service Code and the Retailer Settlement Codes.

RSL has a number of affiliates. One of the affiliates, Rideau St. Lawrence Utilities Inc. (Utilities), is a services company that provides all the manpower required by RSL to operate its distribution system. The costs for these services are passed through to RSL at cost. A corporate charge is then calculated to provide a return on the investments of Utilities. This charge is allocated to each affiliate based on the percentage of total revenue of the Consolidated Corporation. The 2010 actual Corporate Charge to RSL was $18,920, and is $19,139 for the 2012 Test year. The Board Approved 2008 COS Corporate Charge was $19,578.

RSL uses a "Shared Services Model" and tracks costs for operations, maintenance, capital, and administration, with timesheets. RSL continues to use the methods of allocation of Utilities costs to RSL that were reviewed and accepted in its 2008 COS Rate Application. RSL has maintained the complexity rating of three to one for the electricity billing versus the water and sewer, even though the electrical billing is now more complicated, and has more rate types to bill. The Global adjustment is now broken out from the commodity and charged to non-RPP customers only, and other charges have been added to only the electrical bill for the Late Payment Charge, the Special Purpose Charge, and the Ontario Clean Energy Charge.

With the Smart Meter system now collecting meter reads for Residential and for GS < 50 kW electrical meters in 2012, RSL has reduced meter reading expense for these meters by $41,200, from forecast 2011 costs.

Administration costs for the LDC and for Regulatory issues, are significantly more complicated and time consuming than those for water and sewer. The rate setting and the Regulatory issues for water and sewer, are the responsibility of the municipality. RSL has no operational responsibility for water or for sewer, and the municipality deals with the customer for items affecting their revenue. The municipalities pass bylaws setting the rates for water and for sewer, and provide a copy to RSL for entering the appropriate rates into its billing system. RSL is providing a meter reading, billing and collection function only, for municipal water and sewer services.

As required in the Affiliate Relationship Code, RSL has one third of its Board of Directors as an Independent Director.

RSL follows the OEB's Accounting Procedures Handbook (the "APH") in distinguishing work performed between operations and maintenance.

A summary of RSL's operating costs for 2008 Board Approved, 2008 Actual, 2009 Actual, 2010 Actual, 2011 Bridge Year and the 2012 Test Year, is provided in Table 4.1.

The variance used to determine the OM&A accounts requiring analysis as prescribed by the Filing Requirements (EB-2007-0673 issued September 17, 2008) is 1% of Distribution Expenses, which in RSL's case works out to $22,327.

RSL has provided analysis of all variances greater than $20,000 for OM&A.

Table 4.1 provides a summary of OM&A expenses. The summary for 2008 and for 2009, excludes penalties and charitable donations in the amount of $1,112 and $1,944 respectfully.

These amounts are included in Filing Requirements Chapter 2 Appendix 2F - RSL's detailed Trial Balance in Cells C104 & D104, in order to tie into RSL audited Financial Statements. These amounts are excluded from Table 4.1 as they are not allowed expenses for Regulatory purposes.

Table 4.1

Summary of OM&A Expenses

	LRY - 2008 Board-approved	LRY - 2008 Actuals	Variance $	Percentage Change %
Operations	$ 189,708	$ 189,498	-$ 210	-0.11%
Maintenance	$ 401,986	$ 268,548	-$ 133,438	-33.19%
Billing and Collecting	$ 363,576	$ 395,414	$ 31,838	8.76%
Community Relations	$ 254	$ 486	$ 232	91.29%
Administrative and General	$ 631,102	$ 630,237	-$ 865	-0.14%
Total OM&A Expenses	$ 1,586,626	$ 1,484,182	-$ 102,444	-6.46%
Inflation Rate				

	LRY - 2008 Actuals	2009 Actuals	Variance $	Percentage Change %
Operations	$ 189,498	$ 232,774	$ 43,277	22.84%
Maintenance	$ 268,548	$ 292,592	$ 24,045	8.95%
Billing and Collecting	$ 395,414	$ 429,851	$ 34,437	8.71%
Community Relations	$ 486	$ 9,220	$ 8,734	1797.58%
Administrative and General	$ 630,237	$ 655,360	$ 25,123	3.99%
Total OM&A Expenses	$ 1,484,182	$ 1,619,797	$ 135,615	9.14%
Inflation Rate				

	2009 Actuals	2010 Actuals	Variance $	Percentage Change %
Operations	$ 232,774	$ 178,302	-$ 54,472	-23.40%
Maintenance	$ 292,592	$ 346,408	$ 53,816	18.39%
Billing and Collecting	$ 429,851	$ 422,655	-$ 7,195	-1.67%
Community Relations	$ 9,220	$ 450	-$ 8,770	-95.12%
Administrative and General	$ 655,360	$ 695,208	$ 39,848	6.08%
Total OM&A Expenses	$ 1,619,797	$ 1,643,025	$ 23,228	1.43%
Inflation Rate				

	2010 Actuals	Bridge Year Forecast	Variance $	Percentage Change %
Operations	$ 178,302	$ 310,045	$ 131,743	73.89%
Maintenance	$ 346,408	$ 401,700	$ 55,292	15.96%
Billing and Collecting	$ 422,655	$ 422,000	-$ 655	-0.16%
Community Relations	$ 450	$ 3,500	$ 3,050	677.78%
Administrative and General	$ 695,208	$ 669,264	-$ 25,944	-3.73%
Total OM&A Expenses	$ 1,643,025	$ 1,806,509	$ 163,485	9.95%
Inflation Rate				

	Bridge Year Actuals	Test Year Forecast	Variance $	Percentage Change %
Operations	$ 310,045	$ 309,662	-$ 383	-0.12%
Maintenance	$ 401,700	$ 411,374	$ 9,674	2.41%
Billing and Collecting	$ 422,000	$ 391,300	-$ 30,700	-7.27%
Community Relations	$ 3,500	$ 3,500	$ -	0.00%
Administrative and General	$ 669,264	$ 775,892	$ 106,628	15.93%
Total OM&A Expenses	$ 1,806,509	$ 1,891,728	$ 85,218	4.72%
Inflation Rate				

Table 4.2 provides a summary of variances, and an annual growth rate from the last year actuals in 2010, to the 2012 Test Year and from the last rebasing in 2008 to the 2012 Test Year.

Table 4.2

OM&A Comparison

	2010 Actuals	2012 Test	Variance $	Percentage Change %
Test Year versus Most Current Actuals	$1,643,025	$ 1,891,728	$ 248,703	15.14%
	2008 Board-approved	2012 Forecast	Variance $	Percentage Change %
Test Year versus LRY Board-approved	$1,586,626	$ 1,891,728	$ 305,102	19.23%
Simple average of % variance for all years				6.31%
Compound annual growth rate for all years				6.25%

2.0 SUMMARY AND COST DRIVERS TABLE

Detailed Account by Account OM&A Expenses:

In Table 4.3 below, RSL has provided detailed OM&A expenses by account for the 2008 Board Approved, for 2008 Actual, 2009 Actual, 2010 actual, 2011 Bridge, and 2012 Test Years.

Accounts that did not have any activity for the years listed above, were removed, and not included in Table 4.3 for presentation purposes. This provides an easier to read overview as all accounts are presented in one table, and on one page.

The Chapter 2 Filing Requirements Appendix (2-F) model lists all accounts, including those with no activity, per the Filing Requirements.

Table 4.3

Detailed Account by Account OM&A Expenses

Account	Description	2008 Board Approved	2008 Actual	2009 Actual	2010 Actual	Bridge Year	Test Year
Operations							
5005	Operation Supervision and Engineering	$89,889	$ 89,639	$ 103,931	$ 68,611	$ 105,000	$ 108,000
5012	Station Buildings and Fixtures Expense	$1,917	$ 1,997	$ 1,053	$ -	$ 1,000	$ 1,000
5016	Distribution Station Equipment - Operation Labour	$1,329	$ 2,332	$ 2,253	$ -	$ 1,000	$ 1,000
5020	Overhead Distribution Lines and Feeders - Ops Labour	$7,922	$ 8,348	$ 7,962	$ -	$ 2,000	$ 2,000
5035	Overhead Distribution Transformers - Operation	$3,861	$ 3,507	$ 14,394	$ 7,953	$ 10,000	$ 10,000
5065	Meter Expense	$899	$ 552	$ 7,228	$ 19,331	$ 102,856	$ 97,473
5070	Customer Premises - Operation Labour	$324	$ 493	$ -	$ -	$ -	$ -
5085	Miscellaneous Distribution Expenses	$60,985	$ 59,440	$ 62,204	$ 59,217	$ 65,000	$ 67,000
5095	Overhead Distribution Lines and Feeders - Rental Paid	$22,582	$ 23,189	$ 33,748	$ 23,189	$ 23,189	$ 23,189
Total - Operations		**$189,708**	$ 189,498	$ 232,774	$ 178,302	$ 310,045	$ 309,662
Account	**Description**		**2008 Actual**	**2009 Actual**	**2010 Actual**	**Bridge Year**	**Test Year**
Maintenance							
5110	Mtce of Buildings and fixtures - Distribution Stations	$175					
5114	Maintenance of Distribution Station Equipment	$70,700	$ 47,463	$ 43,533	$ 43,624	$ 70,700	$ 71,000
5120	Maintenance of Poles, Towers and Fixtures	$39,343	$ 16,332	$ 19,867	$ 53,602	$ 40,000	$ 41,200
5125	Maintenance of Overhead Conductors and Devices	$94,356	$ 79,061	$ 63,801	$ 116,109	$ 100,000	$ 103,000
5130	Maintenance of Overhead Services	$41,393	$ 34,539	$ 40,874	$ 39,236	$ 50,000	$ 51,500
5135	Overhead Distribution Lines and Feeders - Right of Way	$72,966	$ 42,189	$ 25,952	$ 44,748	$ 40,000	$ 41,200
5145	Maintenance of Underground Conduit	$480	$ 2,235	$ -	$ 1,952	$ 2,000	$ 2,100
5150	Maintenance of Underground Conductors and Devices	$12,464	$ 8,914	$ 9,089	$ 12,515	$ 7,000	$ 7,374
5155	Maintenance of Underground Services	$8,776	$ 11,670	$ 15,936	$ 19,973	$ 22,000	$ 22,500
5160	Maintenance of Line Transformers	$57,325	$ 11,624	$ 63,007	$ 9,212	$ 50,000	$ 51,500
5175	Maintenance of Meters	$4,008	$ 14,521	$ 10,533	$ 5,436	$ 20,000	$ 20,000
Total - Maintenance		$401,986	$ 268,548	$ 292,592	$ 346,408	$ 401,700	$ 411,374
Account	**Description**		**2008 Actual**	**2009 Actual**	**2010 Actual**	**Bridge Year**	**Test Year**
Billing and collecting							
5310	Meter Reading Expense	$53,194	$ 64,415	$ 65,060	$ 68,648	$ 74,000	$ 32,800
5315	Customer Billing	$264,669	$ 268,399	$ 276,355	$ 282,862	$ 272,000	$ 280,200
5320	Collecting	$32,388	$ 40,882	$ 35,368	$ 35,080	$ 36,000	$ 37,100
5325	Cash Over and Short	$0	$ 547	-$ 307			
5335	Bad Debt Expense	$13,325	$ 21,172	$ 53,374	$ 36,067	$ 40,000	$ 41,200
Total - Billing and Collecting		$ 363,576	$ 395,414	$ 429,851	$ 422,655	$ 422,000	$ 391,300
Account	**Description**		**2008 Actual**	**2009 Actual**	**2010 Actual**	**Bridge Year**	**Test Year**
Community Relations							
5410	Community Relations - Sundry	$254	$ 486	$ 453	$ 450	$ 3,500	$ 3,500
5415	Energy Conservation		$ -	$ 8,766	$ -	$ -	$ -
Total - Community Relations		$ 254	$ 486	$ 9,220	$ 450	$ 3,500	$ 3,500
Account	**Description**		**2008 Actual**	**2009 Actual**	**2010 Actual**	**Bridge Year**	**Test Year**
Administrative and General Expenses							
5605	Executive Salaries and Expenses					$ -	$ -
5615	General Administrative Salaries and Expenses	$338,219	$ 308,369	$ 323,239	$ 357,418	$ 358,000	$ 371,800
5620	Office Supplies and Expenses	$15,909	$ 8,952	$ 8,481	$ 10,529	$ 10,000	$ 10,300
5625	Administrative Expense Transferred - Credit	$19,578	$ 59,588	$ 54,790	$ 46,446	$ 28,058	$ 27,754
5630	Outside Services Employed	$72,879	$ 59,948	$ 68,712	$ 59,587	$ 60,000	$ 61,800
5635	Property Insurance	$37,463	$ 33,409	$ 41,302	$ 49,845	$ 45,642	$ 41,807
5655	Regulatory Expenses	$31,458	$ 26,876	$ 31,593	$ 44,992	$ 30,256	$ 122,907
5665	Miscellaneous General Expenses	$85,624	$ 91,861	$ 91,091	$ 91,626	$ 98,000	$ 99,150
5670	Rent	$7,716	$ 8,171	$ 7,485	$ 6,946	$ 8,000	$ 8,200
5675	Maintenance of General Plant	$22,256	$ 31,951	$ 26,724	$ 24,213	$ 28,000	$ 28,800
5680	Electrical Safety Authority Fees				$ 3,606	$ 3,308	$ 3,374
6205	Donations (Charitable Contributions)		$ 1,112	$ 1,944	$ -	$ -	$ -
Total - Administrative and General Expenses		$ 631,102	$ 630,237	$ 655,360	$ 695,208	$ 669,264	$ 775,892
Total OM&A		$ 1,586,626	$1,484,182	$1,619,797	$1,643,025	$ 1,806,509	$1,891,728

OM&A Cost Drivers:

The cost drivers by year are shown in Table 4.4. Listed below are the explanations of the cost drivers.

2008 Board Approved vs. 2008 Actual:

Staffing (payroll and Benefits) for 2008 actual is below 2008 Board approved level by **$66,695** due to gaps in payroll. 2008 Board Approved included the addition of an apprentice, which was filled. Offsetting that was loss of our Operations Manager for six months, a lineman who went on LTD in 2007, never returned to work, and took early retirement in September 2008 for health reasons.

The Operations Manager position was backfilled by the Lead Hand, who was promoted to Foreman. An administrative clerk position was also vacant for the first three months of 2008.

Third Party Service Providers cost for 2008 was under the Board approved level by **$40,000**.

On September 17, 2008, changes to the Canadian Environmental Protection Act, 1999 were published. The changes extended the "End-Of-Use" dates for equipment containing PCBs in a concentration of at least 50 mg/kg but less than 500 mg/kg to December 31, 2009, in sensitive areas such as certain areas, and if the equipment was in any other place the end date was December 31, 2025.

The End-Of-Use changes to 2009, or 2025, allowed RSL to focus in 2009 on removing transformers that contained PCBs of at least 50 mg/kg but less than 500 mg/kg from the sensitive areas listed in the regulation.

Due to the loss of a lineman, and the Operations Manager, and customer development in the last half of 2008 calendar year in RSL's service territory, RSL did not have the resources to organize and complete PCB testing, and contract with a third party for the disposal of transformers that exceeded acceptable levels.

2009 ACTUAL vs. 2008 ACTUAL:

2009 payroll and benefits cost increased by **$17,114** from 2008 actual levels. Wages increased by 3%, or $18,444, as per the Collective Agreement; Employee Health Benefits costs from the service provider increased by 16.5% ($13,417); these amounts were partially offset by the loss of a 4th year apprentice for three months, and his replacement was a 2nd year apprentice ($14,747) resulting in the net increased cost of $17,114 for 2009.

Third Party service Provider costs for 2009 Actual were over 2008 Actual by **$51,383**. In 2009 RSL completed transformer testing for PCBs in sensitive areas, and removed or disposed of those that had a concentration of at least 50 mg/kg but less than 500 mg/kg. This was a regulatory requirement to comply with the Canadian Environmental Protection Act, 1999 amendments, as published in the Canada Gazette September 17, 2008.

Bad Debt Expense for 2009 Actual was **$32,202** higher than 2008 Actual. In 2009 a Grocery Store, classed as an Industrial customer went Bankrupt. RSL had not had an Industrial customer go bankrupt, or leave a bad debt, since St. Lawrence Corp. went bankrupt early in 2006.

Overhead Distribution Lines – Rental Paid Actual Costs for 2009 were **$10,559** higher than 2008 Actuals, as an Invoice from Hydro One for a Long Term Load Transfer adjustment had been incorrectly coded to account 5095 in 2009. It should have been charged to the cost of power.

2010 ACTUAL vs. 2009 ACTUAL:

Payroll and Benefits Actual costs for 2010 were **$1,275** less than 2009 due to the loss of our Operations Manager for a three month period.

This reduced cost was offset by the Collective Agreement 2.5% increase ($16,075), increased cost for employee benefits by MEARIE - 3% ($3,000), by an internal promotion to replace the Operations Manager, and for wage step increases called for in the Collective Agreement.

A third Party contractor was hired to perform back yard tree trimming in our service territory. The contract cost was **$15,900**, and this made our 2010 third party service provider costs, $15,900 higher than our 2009 actuals.

Maintenance of Industrial meters cost for 2010, account 5065, was higher than 2009 Actuals by **$12,103.** These are not smart meter project costs, but were for reconfiguration of metering setups, such as by installing test blocks, so that when we install a new meter for Commercial or Industrial customers, we no longer have to arrange for an outage. The test blocks allow for the meter to be temporarily by-passed while a new meter is installed. The existing setup, required us to disconnect the customer, so while they were disconnected, we upgraded the installation. The test blocks are locked and tagged so the customer cannot by-pass the meter.

2010 Actual Regulatory Expense was **$13,399** higher than 2009 Actual due to Burman Energy Consulting support ($9,000) for RSL's 2011 IRM3 Rate Application LRAM recovery for 2006 to 2009, increased Ontario Energy Board (OEB) costs allocated to RSL, and for increased cost to publish rate application information for public awareness.

2010 Actual **Bad Debt Expense** was **$17,011** less than 2009 Actual because there were no Industrial customer bankruptcies in 2010.

Overhead Distribution Lines – Rental Paid Actual Costs for 2010 were (**$10,559)** Lower than 2009 Actuals, as an Invoice from Hydro One for Long Term Load Transfer had been incorrectly coded to account 5095 in 2009. Once the 2009 posting error was removed, 2010 returned to normal and correct levels.

2011 BRIDGE vs. 2010 ACTUAL:

Payroll and Benefits for 2011 Bridge Year are **$16,834 higher** than 2010 Actuals. The cost increase drivers are - OMERS 17% increase ($8,200), collective Agreement increase of 2.9% ($18,647), and an Operations Manager on staff all year ($36,389). These increase costs were offset by the loss of a lineman – netted by the hiring of an apprentice (-$,23,695), and loss of an accounting clerk for three months, who was replaced by an employee at a lower grade level – savings of $22,727.

Third Party Service Provider cost in 2011 Bridge Year is higher than 2010 actual by **$57,076** for refurbishment work completed on distribution sub stations ($27,076) and for additional work and testing on potential PCB contaminated transformers ($30,000). The planned maintenance for the sub stations (RSL has 9) and for the potential PCB contaminated transformers will be spread out over the term of this COS rate application.

Maintenance of Industrial Meters for the 2011 Bridge Year has **increase by $14,564** from 2010 actuals. As Industrial meters are due for recertification, they are being upgraded to be compatible with the Smart meter Network. CT's and PT's frequently have to be changed, and test blocks are installed (so we no longer have to take the customer out of service to change a meter).

Regulatory Expense for 2011 Bridge Year is lower than 2010 Actuals by **$14,736**. 2008 COS Rate Application costs were amortized over 36 months, ending in April 2011, as at the time RSL filed its application, rebasing was to occur every three years. Subsequent to RSL's application the OEB revised COS filings to be every four (4) years.

Smart Meter Outside Service of **$87,856** has been added to account 5065 for the Bridge year for comparative purposes only. All Smart Meter OM&A costs (including Outside service costs) to December 31, 2011 are included in the Smart Meter Disposition Rider (SMDR) for recovery. More information on these costs will be provided in Exhibit 11 as part of the Smart Meter submission.

2012 TEST vs. 2011 BRIDGE:

Regulatory Expense has **increased by $92,651** as the costs for the 2012 COS Rate application is much greater than it was for 2008, and a regulatory analyst has been added to work on rate applications, and increased regulatory reporting. The analyst cost included is an annual cost of $75,676 which is payroll plus overhead at 54% for 2012. The other additional Regulatory costs are for Consultants, Intervenors, Lawyers, and Advertising (to keep RSL customers informed on the process and the results therein).

Table 4.4

OM&A Cost Drivers Table (Appendix 2-G)

OM&A	2008 Actual	2009 Actual	2010 Actual	2011 Bridge Year	2012 Test Year
Opening Balance	$ 1,586,626	$ 1,484,182	$ 1,619,797	$ 1,643,025	$ 1,806,509
Staffing (payroll and Benefits)	-$ 66,695	$ 17,114	-$ 1,275	$ 16,834	-$ 4,635
Third Party Service Providers	-$ 40,000	$ 51,383	$ 15,900	$ 57,076	$ -
Mtce of Industrial Meters			$ 12,103	$ 14,564	
Regulatory Expense	-$ 4,582	$ 4,717	$ 13,399	-$ 14,736	$ 92,651
Bad Debt Expense	$ 7,847	$ 32,202	-$ 17,011	$ 3,933	$ 1,200
Training + Safety + CDM		$ 8,766			
Property Insurance		$ 7,893	$ 8,543	$ 1,455	-$ 3,835
Smart Meter Outside Service				$ 87,856	-$ 5,383
O/H Dist Lines - Rental Paid		$ 10,559	-$ 10,559		
Remaining Balance	$ 986	$ 2,981	$ 2,128	-$ 3,498	$ 5,221
Closing Balance	$ 1,484,182	$ 1,619,797	$ 1,643,025	$ 1,806,509	$ 1,891,728

OM&A Cost Per Customer and Full Time Equivalent:

The number of customers is calculated as the average from the sum of the total for the end of the prior year, plus the total for the end of the current year. The customer count for Sentinel and Street Lights is based on the number of connections. The OM&A cost per customer is fairly consistent, until the cost for the Smart meter Project are added into the Rate Base and OM&A in 2011.

Account 5065 includes Smart Meter OM&A costs for 2011 of $87,856, and $82,473 for 2012.

The number of Full Time Equivalent Employees (FTEE) based on a headcount approach, submitted in our 2008 COS Application was 13.25. The count of 13.25 did not include 0.6 FTEE for overtime, nor did it include 0.65 FTEE for summer students. RSL has hired two college or university students each summer for several years, to fill in for regular staff who are on vacation, to work on projects, and as a possible screening tool for prospective future employees.

After reviewing the Electricity Reporting and Record Keeping Requirements (RRR) Version dated May 1, 2010, RSL believes that overtime and hours worked by summer students should be included in the FTEE. 2012 FTEE has been calculated with overtime and student hours included in the base calculation. For 2008 the costs were included in the OM&A dollars, but the hours and the resultant FTEE did not include them. For comparison purposes, 2008 Board Approved FTEE has been restated as 14.5 FTEE (13.25 + .6 + .65).

RSL’s FTEE has been declining due to employee health issues, and due to employees leaving or retiring. When employees go on extended sick leave or Long Term Disability, they have not been replaced until we were advised in writing, that they are not going to return to work. When employees leave, it can take several months to find their replacement. RSL is looking to replace those employees who are retiring, or not returning to work, and to add a Regulatory Analyst.

Table 4.5

OM&A Cost per Customer and Full Time Equivalent (Appendix 2-I)

	LRY - Board Approved	LRY - Actual	Year 2 Actual	Year 1 Actual	Bridge Year	Test Year
	2008	2008	2009	2010	2011	2012
Number of Customers	7,549	7,563	7,578	7,642	7,679	7,693
Total OM&A from Appendix 2-G	$ 1,586,626	$ 1,484,182	$ 1,619,797	$ 1,643,025	$ 1,806,509	$ 1,891,728
OM&A cost per customer	$ 210.18	$196.24	$213.75	$215.00	$235.25	$245.89
Number of FTEEs	14.5	14.12	13.58	13.35	13.31	14.43
Customers/FTEEs	520.62	535.79	558.09	572.60	576.82	533.30
OM&A Cost per FTEE	109,422.48	105,144.12	119,290.87	123,108.90	135,697.63	131,132.20

Regulatory Costs:

RSL Regulatory Costs are shown in the Table 4.6 below.

All 2012 Test Year Regulatory Costs are being treated as on-going, and will be incurred each Year of the four year rebasing period. The OEB Annual Assessment, OEB Section 30, Other regulatory agency fees (ESA) are annual costs. The addition of a Regulatory Analyst for Rate Applications, and other Regulatory reporting requirements is an annual cost.

Expected Legal costs, Consultant Costs, and Intervenor costs have all been Annualized to be treated as ongoing. The Legal costs of $8,750, Consultants costs of $15,000, and the Intervenor Costs entered in Table 4.5, are one quarter of the expected costs for RSL;s 2012 COS Rate Application. Total expected legal costs are $35,000, Consultants cost of $60,000, Intervenor costs of $20,000, and $6,250 for Advertising expense.

The One-time cost of $9,000 in 2010 was for Consulting Costs for LRAM.

The ESA cost of $3,142 in 2008 was shown as a one-time cost, as this cost should have been entered in account 5680, not in Regulatory Costs. The ESA cost is an on-going cost for OM&A.

Table 4.6

Regulatory Costs (Appendix 2-H)

	Regulatory Cost Category	USoA Account	One-time Cost? 2	Last Rebasing Year - 2008	Last Year of Actuals - 2010	Bridge Year - 2011	Annual % Change	Test Year - 2012	Annual % Change
	(A)	(B)	(D)	(E)	(F)	(G)	(H) = [(G)-(F)]/(F)	(I)	(J) = [(I)-(G)]/(G)
1	OEB Annual Assessment	5655	On-Going	$ 10,912	$ 12,789	$ 14,455	13.03%	$ 15,000	3.77%
2	OEB Hearing Assessments (applicant-								
3	OEB Section 30 Costs (OEB-initiated)	5655	On-Going	$ 355	$ 313	$ 350	11.82%	$ 350	0.00%
4	New Hire for Regulatory Matters	5655	On-Going					$ 75,676	
5	Legal costs for regulatory matters	5655	On-Going	$ 2,407	$ 3,611	$ 3,040	-15.81%	$ 8,750	187.83%
6	Consultants' costs for regulatory matters	5655	On-Going	$ 5,699	$ 9,868	$ 7,160	-27.44%	$ 15,000	109.50%
7	Operating expenses associated with staff resources allocated to regulatory matters	5655	On-Going	$ 629	$ 1,000	$ 748	-25.20%	$ 1,081	44.52%
8	Operating expenses associated with other resources - Publication costs	5655	On-Going	$ 607	$ 4,923	$ 766	-84.44%	$ 1,250	63.19%
9	Other regulatory agency fees or assessments	5655	On-Going	$ 800	$ -	$ 800		$ 800	0.00%
10	ESA Annual Assessment - s/b GL 5680	5655	On-Time	$ 3,142					
11	Intervenor costs	5655	On-Going	$ 2,325	$ 3,488	$ 2,937	-15.80%	$ 5,000	70.24%
12	Consultants' costs for regulatory matters -	5655	On-Time		$ 9,000	$ -	-100.00%		
12	Sub-total - Ongoing Costs 3			$ 23,734	$ 35,992	$ 30,256	-15.94%	$ 122,907	306.22%
13	Sub-total - One-time Costs 4			$ 3,142	$ 9,000	$ -	-100.00%	$ -	
14	Total			$ 26,876	$ 44,992	$ 30,256	-32.75%	$ 122,907	306.22%

Low-Income Energy Assistance Programs (Leap):

The Board LEAP Report, issued in March 2009, determined that the greater of 0.12% of a distributor's distribution revenue requirement, or $2,000 is a reasonable commitment by all distributors to emergency financial assistance.

RSL's 2012 COS Service Revenue Requirement is $2,736,959, and 0.12 percent of that is $3,284,35. RSL has provided LEAP funding of $3,500, and has included that cost in its 2012 OM&A in account 5410.

Charitable Donations:

RSL has not made any Charitable Donations, and does not wish to recover any in its 2012 COS Rate Application, except for contributions such as those described above that provide assistance to RSL's customers in paying their electricity bills.

RSL has not made, and is not claiming for recovery of any political contributions.

3.0 VARIANCE ANALYSES

The variance used to determine the OM&A accounts requiring analysis has been prescribed by the Filing Requirements (EB-2007-0673 issued September 17, 2008) 1% of Distribution Expenses, which works out to $22,327. RSL has provided analysis of all variances greater than $20,000 for OM&A for 2008 Board Approved, for 2010 Actuals, and for the 2012 Test year.

Variance Analysis detail is provided in Table 4.7.

Account 5005 – Operation Supervision:

The $39,389 variance is attributable to the loss of the Operations Manager in early 2010, and the resulting vacancy for a few months, until the position was filled.

Account 5065 – Meter Expense:

The increase of $78,142 for 2012 from 2010 is attributable to $82,472 OM&A for Smart Meters. In 2008 and 2010, as directed by the Board, all Smart Meter OM&A costs were collected in account 1556 for later disposition, subject to a prudence review. Details are provided in Exhibit 9, in the Schedule on Smart Meters.

Account 5114 – Maintenance of Distribution Station Equipment:

The variance is due to the fact that all eleven (11) of RSL's wholesale meters points were purchased from Hydro One from 2005 to 2008 inclusive. When purchased, and upgraded to the required IESO standards, the costs were capitalized. With all new units, there was an abnormally low amount of maintenance required for 2008 to 2010. In fact the last two sights were purchased, and upgraded in October of 2008, so there were very little maintenance costs on these two sites.

The wholesale meters have a 6 year seal life. Beginning in 2011 two or more of these will be replaced each year, and the costs will be maintenance, not capital. In addition, as the units get older, there will be more maintenance required.

The maintenance costs for 2011 and 2012 will return to the TEST Year level of $71,000.

Account 5120 – Maintenance Poles, Towers and Fixtures:

Due to the loss of the Operations Manager for 6 months in 2008, and a Journeyman Lineman for the year, plus several unexpected customer driven Capital Projects in the second half of 2008, RSL was did not have the resources to attain the originally planned system maintenance in 2008. 2008 Board Approved COS included a cost of $39,518 for this account. In 2010, staff maintenance levels had returned to the planned levels and the residual increase was due to wage and benefit changes.

Account 5125 – Maintenance Overhead Conductors and Devices:

Due to the loss of the Operations Manager for 6 months in 2008, and a Journeyman Lineman for the year, plus several unexpected customer driven Capital Projects in the second half of 2008, RSL was did not have the resources to attain the planned system maintenance in 2008. 2008 Board Approved COS included a cost of $94,356 for this account. In 2010, staff maintenance levels returned to the planned levels, and the residual increase was due to wage and benefit changes.

Account 5160 – Maintenance of Line Transformers:

RSL has completed testing of its transformers for PCB contamination, and removed the contaminated transformers from sensitive areas. The increased cost for 2012 is for the start of a four to five year program to eliminate PCB contaminated transformers in our service territory. 2011 costs include RSL lineman collecting oil samples, and the cost of the tests performed by third party service providers.

Account 5310 – Meter Reading Expense:

2012 Test Year meter reading costs for electricity meters has dropped by $35,848 from 2010 actuals (over a 50% reduction), due to the installation and activation of the Smart Meter system. Manual meters reads are no longer required for Residential and Commercial meters. The residual cost in the account is for Industrial meters, and initial site investigation for connectivity issues with the smart meter network.

Account 5615 – General Administrative Salaries and Expenses:

As stated in Chapter 2 of The Filing Requirements, "where there are three or fewer employees in any category, the applicant should aggregate this category with the category to which it is most closely related. RSL has three or fewer employees in account 5605 and in account 5615, as a result, both accounts have been aggregated into account 5615.

2012 Test Year totals for the combined accounts 5605 and 5615, are higher than 2008 Actuals by $63,461. An accounting clerk was off work for an extended period in 2008, and the rest of the variance is attributable to four years of annual salary increases.

Account 5625 – Administrative Expenses – Transferred – Credit:

At the time of RSL's, and all the affiliates Incorporation in 2000, all vehicles were owned by Utilities Inc. In 2002 another line truck was purchased and added to Utilities Inc. assets. Account 5625 includes an allocated cost of depreciation from Utilities Inc. to RSL.

Line trucks are primarily used by RSL, and in 2008 the decision was made that line trucks should be purchased by RSL and added to its assets. As all but one of the line trucks are now owned by RSL, the depreciation allocation is being reduced each year and may soon disappear, as the 2002 purchased line truck will be fully amortized at the end of 2011.

The allocated depreciation expense for 2008 Actual was $39,249, for 2010 Actual it was $27,526 and for 2012 Test it is $8,615 – for light vehicles (1/2 Ton Trucks).

Table 4.7

Variance Analysis

Account	Description	Last Board-approved Rebasing Year (2008 Actuals)	Most Current Actual Year (2010)	Test Year (2012)	Test Year Versus Last Rebasing		Test Year Versus Most Current Actuals	
					Variance ($)	Percentage	Variance ($)	Percentage
Operations								
5005	Operation Supervision and Engineering	$ 89,639	$ 68,611	$ 108,000	$ 18,361	20.48%	$ 39,389	57.41%
5010	Load Dispatching	$ -	$ -	$ -	$ -		$ -	
5012	Station Buildings and Fixtures Expense	$ 1,997	$ -	$ 1,000	-$ 997	-49.93%	$ 1,000	
5014	Transformer Station Equipment - Operation Labour	$ -	$ -	$ -	$ -		$ -	
5015	Transformer Station Equipment - Operation Supplies and Expenses	$ -	$ -	$ -	$ -		$ -	
5016	Distribution Station Equipment - Operation Labour	$ 2,332	$ -	$ 1,000	-$ 1,332	-57.12%	$ 1,000	
5017	Distribution Station Equipment - Operation Supplies and Expenses	$ -	$ -	$ -	$ -		$ -	
5020	Overhead Distribution Lines and Feeders - Operation Labour	$ 8,348	$ -	$ 2,000	-$ 6,348	-76.04%	$ 2,000	
5025	Overhead Distribution Lines and Feeders - Operation Supplies and Expenses	$ -	$ -	$ -	$ -		$ -	
5030	Overhead Sub-transmission Feeders - Operation	$ -	$ -	$ -	$ -		$ -	
5035	Overhead Distribution Transformers - Operation	$ 3,507	$ 7,953	$ 10,000	$ 6,493	185.12%	$ 2,047	25.73%
5040	Underground Distribution Lines and Feeders - Operation Labour	$ -	$ -	$ -	$ -		$ -	
5045	Underground Distribution Lines and Feeders - Operation Supplies and Expense	$ -	$ -	$ -	$ -		$ -	
5050	Underground Sub-transmission Feeders - Operation	$ -	$ -	$ -	$ -		$ -	
5055	Underground Distribution Transformers - Operation	$ -	$ -	$ -	$ -		$ -	
5060	Street Lighting and Signal System Expense	$ -	$ -	$ -	$ -		$ -	
5065	Meter Expense	$ 552	$ 19,331	$ 97,473	$ 96,921	17546.36%	$ 78,142	404.22%
5070	Customer Premises - Operation Labour	$ 493	$ -	$ -	-$ 493	-100.00%	$ -	
5075	Customer Premises - Operation Materials and Expenses	$ -	$ -	$ -	$ -		$ -	
5085	Miscellaneous Distribution Expenses	$ 59,440	$ 59,217	$ 67,000	$ 7,560	12.72%	$ 7,783	13.14%
5090	Underground Distribution Lines and Feeders - Rental Paid	$ -	$ -	$ -	$ -		$ -	
5095	Overhead Distribution Lines and Feeders - Rental Paid	$ 23,189	$ 23,189	$ 23,189	-$ 0	0.00%	-$ 0	0.00%
5096	Other Rent	$ -	$ -	$ -	$ -		$ -	
Total - Operations		$ 189,498	$ 178,302	$ 309,662	$ 120,165	63.41%	$ 131,360	73.67%
Account	**Description**							
Maintenance								
5105	Maintenance Supervision and Engineering	$ -	$ -	$ -	$ -		$ -	
5110	Maintenance of Buildings and Fixtures - Distribution Stations	$ -	$ -	$ -	$ -		$ -	
5112	Maintenance of Transformer Station Equipment	$ -	$ -	$ -	$ -		$ -	
5114	Maintenance of Distribution Station Equipment	$ 47,463	$ 43,624	$ 71,000	$ 23,537	49.59%	$ 27,376	62.76%
5120	Maintenance of Poles, Towers and Fixtures	$ 16,332	$ 53,602	$ 41,200	$ 24,868	152.26%	-$ 12,402	-23.14%
5125	Maintenance of Overhead Conductors and Devices	$ 79,061	$ 116,109	$ 103,000	$ 23,939	30.28%	-$ 13,109	-11.29%
5130	Maintenance of Overhead Services	$ 34,539	$ 39,236	$ 51,500	$ 16,961	49.11%	$ 12,264	31.26%
5135	Overhead Distribution Lines and Feeders - Right of Way	$ 42,189	$ 44,748	$ 41,200	-$ 989	-2.34%	-$ 3,548	-7.93%
5145	Maintenance of Underground Conduit	$ 2,235	$ 1,952	$ 2,100	-$ 135	-6.03%	$ 148	7.57%
5150	Maintenance of Underground Conductors and Devices	$ 8,914	$ 12,515	$ 7,374	-$ 1,540	-17.27%	-$ 5,141	-41.08%
5155	Maintenance of Underground Services	$ 11,670	$ 19,973	$ 22,500	$ 10,830	92.81%	$ 2,527	12.65%
5160	Maintenance of Line Transformers	$ 11,624	$ 9,212	$ 51,500	$ 39,876	343.06%	$ 42,288	459.07%
5165	Maintenance of Street Lighting and Signal Systems	$ -	$ -	$ -	$ -		$ -	
5170	Sentinel Lights - Labour	$ -	$ -	$ -	$ -		$ -	
5172	Sentinel Lights - Materials and Expenses	$ -	$ -	$ -	$ -		$ -	
5175	Maintenance of Meters	$ 14,521	$ 5,436	$ 20,000	$ 5,479	37.73%	$ 14,564	267.94%
5178	Customer Installations Expenses - Leased Property	$ -	$ -	$ -	$ -		$ -	
5195	Maintenance of Other Installations on Customer Premises	$ -	$ -	$ -	$ -		$ -	
Total - Maintenance		$ 268,548	$ 346,408	$ 411,374	$ 142,826	53.18%	$ 64,966	18.75%
Account	**Description**							
Billing and Collecting								
5305	Supervision	$ -	$ -	$ -	$ -		$ -	
5310	Meter Reading Expense	$ 64,415	$ 68,648	$ 32,800	-$ 31,615	-49.08%	-$ 35,848	-52.22%
5315	Customer Billing	$ 268,399	$ 282,862	$ 280,200	$ 11,801	4.40%	-$ 2,662	-0.94%
5320	Collecting	$ 40,882	$ 35,080	$ 37,100	-$ 3,782	-9.25%	$ 2,020	5.76%
5325	Collecting - Cash Over and Short	$ -	$ -	$ -	$ -		$ -	
5330	Collection Charges	$ -	$ -	$ -	$ -		$ -	
5335	Bad Debt Expense	$ 21,719	$ 36,067	$ 41,200	$ 19,481	89.70%	$ 5,133	14.23%
5340	Miscellaneous Customer Accounts Expenses	$ -	$ -	$ -	$ -		$ -	
Total - Billing and Collecting		$ 395,414	$ 422,655	$ 391,300	-$ 4,114	-1.04%	-$ 31,355	-7.42%
Account	**Description**							
Community Relations								
5405	Supervision	$ -	$ -	$ -	$ -		$ -	
5410	Community Relations - Sundry	$ 486	$ 450	$ 3,500	$ 3,014	620.36%	$ 3,050	677.78%
5415	Energy Conservation	$ -	$ -	$ -	$ -		$ -	
5420	Community Safety Program	$ -	$ -	$ -	$ -		$ -	
5425	Miscellaneous Customer Service and Informational Expenses	$ -	$ -	$ -	$ -		$ -	
5505	Supervision	$ -	$ -	$ -	$ -		$ -	

4.0 EMPLOYEE COMPENSATION BREAKDOWN

Table 4.8 provides the Employee Compensation Breakdown for 2008 Board Approved, 2008 Actual, 2009 Actual, 2010 Actual, 2011 Bridge Year, and the 2012 Test year.

As stated in Chapter 2 of The Filing Requirements, "where there are three or fewer employees in any category, the applicant should aggregate this category with the category to which it is most closely related. RSL has shown the headcounts split between the Executive and CUPE, but Compensation and Benefits have been aggregated.

RSL employee benefit programs are provided by the MEARIE Group, and by OMERS. The MEARIE program is fully funded by RSL and covers health, dental, plus life insurance. OMERS is a defined benefit plan that requires employee contributions from date of hire, and these contributions are to be matched by the employer. Other benefit costs are Canada Pension Plan, Employment Insurance, Extended Health Tax, and Workers Compensation and Insurance.

For this report, RSL has included regular wages, overtime, and benefits listed above, but excluded compensation for Statutory Holidays, and for annual employee vacations.

RSL has no post-retirement benefits for its employees, and RSL has no employees. The employees and costs incurred are provided by the Affiliate Rideau St. Lawrence Utilities Inc.

RSL's submission for 2008 COS (EB-2007-0762) provided a FTEE based on headcounts, and did not include overtime hours, or the hours for summer students employed by RSL. As the wages and benefits, if applicable, were included it the costs for 2008 Test Year, the FTEE of 0.6 for overtime hours, and 0.65 for student hours should have been included in the FTEE for 2008 Board Approved. RSL has added these into the FTEE presented here for 2008 Board Approved, resulting in the increase from 13.25 to 14.5. 2012 COS has been calculated, including these, so the 14.5 FTEE provides a consistent comparison.

RSL FTEE for 2008 Board approved was 14.5 (as adjusted) 14.12 for 2008 Actual, 13.58 for 2009 Actual, 13.35 for 2010 Actual, 13.31 for 2011 Bridge, and 14.43 for 2012 Test year.

The decline in FTEE for 2008 to 2011, was due to sickness, early retirement, and employees leaving RSL. RSL experienced several employees going on extended sick leaves (LTD), and did not replace them until confirmation was received in writing that they were not returning to work at RSL. The decline in FTEE also reduced the expected levels for Salaries and Wages.

For 2012 Test Year a Regulatory Analyst has been added, accounting for the FTEE increase to 14.43 for 2012, and increases the salaries and wages by $56,160. Salaries and Wages have increased based on the Collective Agreement by 3.0% (%18,444) in 2009 (2008 increase was built into the Board Approved and into the Actual), by 2.5% ($16,075) in 2010, and by 2.9% in 2011 ($18,647) and 2012 ($19,188).

MEARIE benefit costs increased by 16.5% ($15,875) in 2010, and had no increase for 2011 or for 2012.

OMERS required contributions for 2009 and 2010 did not include a rate increase. In 2010 the OMERS Sponsors Corporation (SC) announced its strategy to return the Plan to full funding by increasing contribution rates by 2.9% over three years.

For 2011 OMERS rate increase affect for RSL was 15% or $8,200, for 2012 it is an additional 15%, plus the required contributions for the Regulatory analyst, for a 2012 impact of about $14,000.

A further OMERS increase for 2013, as announced will be create about the same added cost impact.

For 2012 CPP & EI are increasing by 3.7% and by 6.8% respectfully, and will increase RSL's annual contribution cost by approximately $3,000.

The average yearly base wages have a bump in 2008 Actuals as there were 53 pay weeks in 2008.

Table 4.8

Employee Costs (Appendix 2-K)

	LRY - Board Approved 2008	LRY - 2008 Actual	2009 Actual	2010 Actual	Bridge Year 2011	Test Year
Number of Employees (FTEs including Part-Time)[1]						
Executive	3.00	3.00	3.00	3.00	3.00	3.00
Management						
Non-Union						
Union	11.50	11.12	10.58	10.35	10.31	11.43
Total	14.50	14.12	13.58	13.35	13.31	14.43
Number of Part-Time Employees						
Executive						
Management						
Non-Union						
Union						
Total	-	-	-	-	-	-
Total Salary and Wages						
Executive						
Management						
Non-Union						
Union	$ 728,992	$ 703,179	$ 719,531	$ 731,974	$ 741,953	$ 826,761
Total	$ 728,992	$ 703,179	$ 719,531	$ 731,974	$ 741,953	$ 826,761
Current Benefits						
Executive						
Management						
Non-Union						
Union	$ 188,862	$ 211,843	$ 243,320	$ 243,788	$ 273,817	$ 312,503
Total	$ 188,862	$ 211,843	$ 243,320	$ 243,788	$ 273,817	$ 312,503
Accrued Pension and Post-Retirement Benefits						
Executive						
Management						
Non-Union						
Union						
Total	$ -	$ -	$ -	$ -	$ -	$ -
Total Benefits (Current + Accrued)						
Executive	$ -	$ -	$ -	$ -	$ -	$ -
Management	$ -	$ -	$ -	$ -	$ -	$ -
Non-Union	$ -	$ -	$ -	$ -	$ -	$ -
Union	$ 188,862	$ 211,843	$ 243,320	$ 243,788	$ 273,817	$ 312,503
Total	$ 188,862	$ 211,843	$ 243,320	$ 243,788	$ 273,817	$ 312,503
Total Compensation (Salary, Wages, & Benefits)						
Executive	$ -	$ -	$ -	$ -	$ -	$ -
Management	$ -	$ -	$ -	$ -	$ -	$ -
Non-Union	$ -	$ -	$ -	$ -	$ -	$ -
Union	$ 917,854	$ 915,021	$ 962,851	$ 975,762	$ 1,015,770	$ 1,139,263
Total	$ 917,854	$ 915,021	$ 962,851	$ 975,762	$ 1,015,770	$ 1,139,263
Compensation - Average Yearly Base Wages						
Executive						
Management						
Non-Union						
Union	$48,041	$49,358	$49,040	$51,610	$51,849	$53,259
Total						
Compensation - Average Yearly Overtime						
Executive						
Management						
Non-Union						
Union	$ 3,103	$ 4,144	$ 3,945	3,219	3,895	4,035
Total						
Compensation - Average Yearly Incentive Pay						
Executive						
Management						
Non-Union						
Union						
Total						
Compensation - Average Yearly Benefits						
Executive						
Management						
Non-Union						
Union	$ 13,025	$ 15,003	$ 17,918	$ 18,261	$ 20,572	$ 21,656
Total						
Total Compensation	$ 917,854	$ 915,021	$ 962,851	$ 975,762	$ 1,015,770	$ 1,139,263
Total Compensation C	$874,211	$807,249	$885,654	$936,016	$922,070	$1,030,480

5.0 SHARED SERVICES/CORPORATE COST ALLCATION

A summary of shared services between Rideau St. Lawrence Distribution Inc. and its affiliates are:

1. Meter Reading
2. Billing
3. Collecting
4. Administration
5. Operations

Shared Services Cost Allocation Methodology:

In 2000, when Rideau St. Lawrence Distribution Inc. (RSL) and Rideau St. Lawrence Utilities Inc. (Utilities) were formed, employees, tools, administration buildings, office equipment, water heaters and rolling stock (vehicles) were transferred into Utilities so that Utilities could provide services to RSL as well as to its municipal shareholders. These were services that were being provided by the four former Municipal Electric Utilities before they merged in 2000 to become Rideau St. Lawrence Holdings Inc. and its subsidiaries.

In 2004, tools and rolling stock were to be transferred from Utilities to RSL. These items are used primarily for distribution activities. The tools were transferred, but it was not economically viable to transfer the rolling stock due to tax implications. Instead, when it is time to replace a line truck, it will be purchased by RSL rather than Utilities, as the majority of the line truck use will be for RSL purposes. Rolling stock costs are recorded and then applied as part of our overhead rate. The cost for the new truck will be in RSL, and will be charged to Utilities as used for Utilities work, and charges by Utilities to RSL will be reduced. The last two line trucks were purchased by RSL, the LDC.

Utilities provide water meter readings, billing, and collecting functions for municipalities and for RSL. These services are provided on a shared cost basis.

The meter reading service for the Village of Westport is provided by a third party. The balance of the meter reading costs are allocated between RSL and Utilities based on the number of reads per year per service, with RSL being responsible for the hydro meter reading costs, and Utilities for the water meter reading costs. In 2004, approximately 1800 new water meters were installed in the Township of South Dundas with a remote touch pad installed beside the hydro meter. Based on the number of meter readings (47,334 electric and 35,916 water), and the ease of attaining the readings (inside /outside meters, demand Commercial meters), the meter reading cost are split 60% for electrical, and 40% for water.

The Smart Meter Infrastructure has been activated for the 2012 Test year, and electricity meter reading costs have been reduced from $74,000 in the Bridge Year to $32,800 in the TEST Year. 2012 meter reading costs are for Industrial and demand meters that are not part of the Smart Meter Project, and for investigation and inspection of the Smart Meter non reading issues.

To determine the bill production calculation cost for hydro, we first identify and remove costs specific for hydro (settlement costs etc.) that are captured in this account. The hydro bill has been assigned a factor of three compared to one for the water bill based on the complexity of the hydro bill, and the additional procedures we have to follow to calculate the hydro bill. A hydro bill can have up to 25 different rates with up to 52 different stat profiles to calculate compared to a maximum of 3 rate types, and five stat profiles for the water bill. This complexity rating along with the number of bills produced annually (hydro 59,622 and water 35,916) provides an allocation factor of 80% for hydro bills and 20% for water bills to be applied to common billing costs to determine the common costs to be allocated to RSL. The hydro only costs are then added to this, to produce the billing cost to be assigned to RSL. Collections costs are allocated based on the number of bills issued: 59,622 for hydro versus 35,916 for water, or 62% to 38%.

Five percent is added to Utilities costs for the time/cost of the executive working on Utilities issues – 5% for Operations Supervision outside costs, and 5% Administration for inside costs, such as billing and collecting.

The Utilities revenue is derived from Hot Water Tank rentals, Water and Sewer billing, Street Light maintenance, and a small amount of contract work. The executive perform a caretaker roll only for these services, as they are all mature services, and are not being actively pursued or expanded. They are a continuation of services that have been provided for years, and all regulatory issues, rates, and revenue issues are handled by the municipalities.

The balance of the OM&A costs are charged based on actual labour costs, plus an overhead rate of 54% for 2012. Each employee completes a time sheet detailing the time and the type of work they performed.

The expenses for these services are shared in proportion of their use and are shared on a fully allocated cost basis. The cost sharing is reviewed from time to time to ensure that the cost split reflects practice.

Corporate Cost Allocation:

Rideau St. Lawrence Distribution Inc. (RSL) has affiliates, as shown in Exhibit 1. One of the affiliates, Rideau St. Lawrence Utilities Inc. (Utilities), is a services company that provides all the manpower required by RSL to operate its distribution system. The costs for these services are passed through to RSL at cost. A corporate charge is then calculated to provide a return on the investments of Utilities. This charge is allocated to each affiliate based on the percentage of total revenue of the Consolidated Corporation. In 2008 the corporate charge to RSL was $20,339, compared to $19,578 in the approved 2008 EDR. The corporate charge for 2009 was $18,919, and for 2010 - $18,920. For 2011 Bridge Year it is $18,765, and for 2012 TEST year it is $19,139.

There are no Board of Director-related costs for affiliates included in this application.

Table 4.9

Shared Services/Corporate Cost Allocation for 2008

Year: 2008

Name of Company		Service Offered	Pricing Methdology	Price for the Service	Cost for the Service	Percentage Allocation
From	To			$	$	%
RSL	Utilities Inc.	Meter Reading	Split costs on meter count by service		$44,820	40
RSL	Utilities Inc.	Billing costs	Settlement costs		$44,524	20
RSL	Utilities Inc.	Collection Costs	Allocated based on # of bills per service		$26,148	42.3
RSL	Utilities Inc.	Supervision	Percentage of Meter Reading Cost - 5%	$2,241		5% of service cost
RSL	Utilities Inc.	Administration	5% of Billing & Collecting Costs charged	$3,534		5% of service cost
RSL	Services Inc.	Administration	$100 per Invoice Issued and Collected	$200		n/a

Note:
This appendix must be completed in relation to each service provided or received for the Historical (actuals), Bridge and Test years.

Appendix 2-L
Shared Services/Corporate Cost Allocation

Year: 2009

Name of Company		Service Offered	Pricing Methdology	Price for the Service	Cost for the Service	Percentage Allocation
From	To			$	$	%
RSL	Utilities Inc.	Meter Reading	Split costs on meter count by service		$41,773	40
RSL	Utilities Inc.	Billing costs	Settlement costs		$46,353	20
RSL	Utilities Inc.	Collection Costs	Allocated based on # of bills per service		$25,929	42.3
RSL	Utilities Inc.	Supervision	Percentage of Meter Reading Cost - 5%	$2,089		5% of service cost
RSL	Utilities Inc.	Administration	5% of Billing & Collecting Costs charged	$2,318		5% of service cost
RSL	Services Inc.	Administration	$100 per Invoice Issued and Collected	$200		n/a

Year: 2010

Name of Company		Service Offered	Pricing Methdology	Price for the Service	Cost for the Service	Percentage Allocation
From	To			$	$	%
RSL	Utilities Inc.	Meter Reading	Split costs on meter count by service		$44,165	40
RSL	Utilities Inc.	Billing costs	Settlement costs		$49,404	20
RSL	Utilities Inc.	Collection Costs	Allocated based on # of bills per service		$25,724	42.3
RSL	Utilities Inc.	Supervision	Percentage of Meter Reading Cost - 5%	$2,208		5% of service cost
RSL	Utilities Inc.	Administration	5% of Billing & Collecting Costs charged	$2,470		5% of service cost
RSL	Services Inc.	Administration	$100 per Invoice Issued and Collected	$200		n/a

Year: 2011

Name of Company		Service Offered	Pricing Methdology	Price for the Service	Cost for the Service	Percentage Allocation
From	To			$	$	%
RSL	Utilities Inc.	Meter Reading	Split costs on meter count by service		$45,440	40
RSL	Utilities Inc.	Billing costs	Settlement costs		$49,452	20
RSL	Utilities Inc.	Collection Costs	Allocated based on # of bills per service		$30,456	42.3
RSL	Utilities Inc.	Supervision	Percentage of Meter Reading Cost - 5%	$2,272		5% of service cost
RSL	Utilities Inc.	Administration	5% of Billing & Collecting Costs charged	$2,473		5% of service cost
RSL	Services Inc.	Administration	$100 per Invoice Issued and Collected	$200		n/a

Year: 2012

Name of Company		Service Offered	Pricing Methdology	Price for the Service	Cost for the Service	Percentage Allocation
From	To			$	$	%
RSL	Utilities Inc.	Meter Reading	Split costs on meter count by service		$46,840	40
RSL	Utilities Inc.	Billing costs	Settlement costs		$51,012	20
RSL	Utilities Inc.	Collection Costs	Allocated based on # of bills per service		$31,725	42.3
RSL	Utilities Inc.	Supervision	Percentage of Meter Reading Cost - 5%	$2,342		5% of service cost
RSL	Utilities Inc.	Administration	5% of Billing & Collecting Costs charged	$2,551		5% of service cost
RSL	Services Inc.	Administration	$100 per Invoice Issued and Collected	$200		n/a

6.0 PURCHASE OF NON-AFFILITAE SERVICES

RSL does not have a formal documented procurement policy. RSL uses good business practices to obtain pricing. At the time of RSL's formation, competitive quotes were issued, and services purchased to the successful bidder. Since then RSL has been part of competitive RFP's issued by CHEC, and has leveraged the CHEC Group for joint purchasing where no formal RFP was issued.

Purchased non-affiliate services, are listed below in Table 4.10.

Table 4.10

Purchased Non-Affiliate Services

Category:	Nature of Activity Transacted	Approach	2,010	2011 Bridge	2012 Test
Vehicle Repairs & Maintenance					
Garages	Maintenace on Line Trucks	Cost Approach	$18,342	$19,000	$20,000
Transformer Oil Testing					
Cam Tran	PCB Oil Testing	Cost Approach	$0	$30,000	$0
PCB Transformer Disposal	Disposal of PCB Transformers	Quotes		$0	$27,645
Settlement Services					
Utilismart/Kinetiq	Settlement Services	Contract Renewal	$42,000	$42,000	$43,000
Computer Support					
Harris Computer Systems	Billing system support	Informal Comparison	$37,083	$40,000	$41,000
Wholesale Meters / MV90					
Peterborough Utilities	MSP Services	Contract Renewal	$18,785	$25,000	$30,000
Smart Meter OM&A					
Elster + MAS Server	IT/ Software/Services	CHEC RFP	$12,877	$34,372	$25,040
Util-Assist	IT/ Software/Services				$20,000

7.0 DEPRECIATION/AMORTIZATION DEPLETION

In the tables below, RSL has provided details for Depreciation, Amortization, and Depletion by asset group for Historical, Bridge, and Test Years.

No changes were made to the rates of depreciation or amortization for the 2008 to 2010 years inclusive.

With the move to Modified International Financial Reporting Standards (MIFRS) in 2012, and the requirements to restate 2011 in MIFRS format, depreciation and amortization rates were revised in 2011 based on the Typical Useful Life (TUL) provided by the Board Commissioned Provincial Study results provided by Kinectrics. These revisions comply with the Boards Guidelines on amortization/depreciation rates. RSL does use the ½ year rule, in that RSL calculates a half year of depreciation expense in the year of acquisition, and in the year of disposal.

RSL follows the guidelines as set out in the OEB Accounting Procedure Handbook in the capitalization of assets. RSL does not capitalize interest on funds used during construction. RSL does not capitalize any indirect administrative support costs such as Finance, Human Resources or Corporate Services.

Account 1820 has been split into sub accounts for components, as Wholesale Meter Points have a TUL of 25 years, and Distribution sub stations have a TUL of 45 years.

Account 1860 for Meters has also been split into sub account for the different TUL for the assets contained therein. Industrial Meters have retained a 25 Year TUL, the same as it was in prior years.

The other sub accounts totaling $1,294,089.52 are for the 2012 opening balance of Smart Meter Capital additions to date. The group is split between meters (15 year TUL), computers (5 year TUL, and Software (5Year TUL).

Table 4.11

2008 Depreciation and Amortization Expense (Appendix 2-M)

			Year:	2008					
Account	Description	Opening Balance (a)	Less Fully Depreciated[1] (b)	Net for Depreciation (c) = (a) - (b)	Additions (d)	Total for Depreciation (e) = (c) + ½ x (d) [2]	Years (f)	Depreciation Rate (g) = 1 / (f)	Depreciation Expense (h) = (e) / (f)
1805	Land	$84,205		$84,205	$0	$84,205	0		
1808	Buildings	$16,600		$16,600	$59,119	$46,160	50	$0	$923
1810	Leasehold Improvements	$0		$0	$0	$0			
1815	Transformer Station Equipment >50 kV	$0		$0	$0	$0			
1820	Distribution Station Equipment <50 kV	$546,819		$546,819	$115,522	$604,579	25	$0	$24,183
1820	Distribution Station Equipment <50 kV			$0		$0			
1825	Storage Battery Equipment			$0		$0			
1830	Poles, Towers & Fixtures	$290,928		$290,928	$79,565	$330,710	25	$0	$13,228
1835	Overhead Conductors & Devices	$1,646,735		$1,646,735	$42,081	$1,667,775	25	$0	$66,711
1840	Underground Conduit	$461,238		$461,238	$0	$461,238	25	$0	$18,450
1845	Underground Conductors & Devices	$311,876		$311,876	$28,871	$326,311	25	$0	$13,052
1850	Line Transformers	$797,580		$797,580	$106,912	$851,036	25	$0	$34,041
1855	Services (Overhead and Underground)	$154,098		$154,098	$56,990	$182,592	25	$0	$7,304
1860	Meters	$359,722		$359,722	$49,652	$384,548	25	$0	$15,382
1860	Meters (Smart Meters)			$0		$0			
1905	Land			$0		$0			
1906	Land Rights			$0		$0			
1908	Buildings & Fixtures			$0		$0			
1910	Leasehold Improvements			$0	$8,796	$4,398	10	$0	$440
1915	Office Furniture & Equipment (10 Years)			$0		$0			
1915	Office Furniture & Equipment (5 Years)			$0		$0			
1920	Computer Equipment - Hardware			$0		$0			
1920	Computer Equip. - Hardware (Post Mar. 22/04)			$0		$0			
1920	Computer Equip. - Hardware (Post Mar. 19/07	$99,275		$99,275	$34,796	$116,673	5	$0	$23,335
1925	Computer Software	$17,425		$17,425	$63,785	$49,317	5	$0	$9,863
1930	Transportation Equipment	$0		$0	$22,126	$11,063			$2,766
1935	Stores Equipment			$0		$0			
1940	Tools, Shop & Garage Equipment	$111,752		$111,752	$10,817	$117,161	10	$0	$11,716
1945	Measurement & Testing Equipment			$0		$0			
1950	Power Operated Equipment			$0		$0			
1955	Communications Equipment			$0		$0			
1955	Communication Equipment (Smart Meters)			$0		$0			
1960	Miscellaneous Equipment			$0		$0			
1975	Load Management Controls Utility Premises			$0		$0			
1980	System Supervisor Equipment			$0		$0			
1985	Miscellaneous Fixed Assets			$0		$0			
1995	Contributions & Grants	-$258,722		-$258,722	-$102,482	-$309,963	25	$0	-$12,399
etc.				$0		$0			
				$0		$0			
	Total	$4,639,530	$0	$4,639,530	$576,549	$4,927,805			$228,996

Table 4.12

2009 Depreciation and Amortization Expense (Appendix 2-M)

			Year:	2009					
Account	Description	Opening Balance (a)	Less Fully Depreciated[1] (b)	Net for Depreciation (c) = (a) - (b)	Additions (d)	Total for Depreciation (e) = (c) + ½ x (d) [2]	Years (f)	Depreciation Rate (g) = 1 / (f)	Depreciation Expense (h) = (e) / (f)
1805	Land	$84,205		$84,205	$0	$84,205	0		
1808	Buildings	$75,720		$75,720	$6,568	$79,003	50	2%	$1,580
1810	Leasehold Improvements	$0		$0	$0	$0			
1815	Transformer Station Equipment >5(	$0		$0	$0	$0			
1820	Distribution Station Equipment <50	$662,340		$662,340	$1,121	$662,900	25	4%	$26,516
1820	Distribution Station Equipment <50 kV			$0		$0			
1825	Storage Battery Equipment			$0		$0			
1830	Poles, Towers & Fixtures	$370,493		$370,493	$57,191	$399,088	25	4%	$15,964
1835	Overhead Conductors & Devices	$1,688,815		$1,688,815	$55,864	$1,716,747	25	4%	$68,670
1840	Underground Conduit	$461,238		$461,238	$2,588	$462,532	25	4%	$18,495
1845	Underground Conductors & Devices	$340,747		$340,747	$10,427	$345,960	25	4%	$13,838
1850	Line Transformers	$904,492		$904,492	$42,360	$925,672	25	4%	$37,027
1855	Services (Overhead and Undergrou	$211,087		$211,087	$33,811	$227,993	25	4%	$9,120
1860	Meters	$409,373		$409,373	$3,485	$411,116	25	4%	$16,445
1860	Meters (Smart Meters)			$0		$0			
1905	Land			$0		$0			
1906	Land Rights			$0		$0			
1908	Buildings & Fixtures			$0		$0			
1910	Leasehold Improvements	$8,796		$8,796	$0	$8,796	10	10%	$880
1915	Office Furniture & Equipment (10 Years)			$0		$0			
1915	Office Furniture & Equipment (5 Years)			$0		$0			
1920	Computer Equipment - Hardware			$0		$0			
1920	Computer Equip. - Hardware (Post Mar. 22/04)			$0		$0			
1920	Computer Equip. - Hardware (Post	$134,070	-$800	$134,870	$18,112	$143,927	5	20%	$28,785
1925	Computer Software	$81,210		$81,210	$38,393	$100,406	5	20%	$20,081
1930	Transportation Equipment	$22,126		$22,126	$267,034	$155,644			$22,221
1935	Stores Equipment			$0		$0			
1940	Tools, Shop & Garage Equipment	$122,569		$122,569	$6,640	$125,889	10	10%	$12,589
1945	Measurement & Testing Equipment			$0		$0			
1950	Power Operated Equipment			$0		$0			
1955	Communications Equipment			$0		$0			
1955	Communication Equipment (Smart Meters)			$0		$0			
1960	Miscellaneous Equipment			$0		$0			
1975	Load Management Controls Utility Premises			$0		$0			
1980	System Supervisor Equipment			$0		$0			
1985	Miscellaneous Fixed Assets			$0		$0			
1995	Contributions & Grants	-$361,204		-$361,204	$216	-$361,096	25	4%	-$14,444
etc.				$0		$0			
				$0		$0			
	Total	$5,216,079	-$800	$5,216,879	$543,810	$5,488,784			$277,767

Table 4.13

2010 Depreciation and Amortization Expense (Appendix 2-M)

Account	Description	Opening Balance	Less Fully Depreciated [1]	Net for Depreciation	Additions	Total for Depreciation	Years	Depreciati on Rate	Depreciation Expense
		(a)	(b)	(c) = (a) - (b)	(d)	(e) = (c) + ½ x (d) [2]	(f)	(g) = 1 / (f)	(h) = (e) / (f)
1805	Land	$84,205		$84,205	$0	$84,205	-		
1808	Buildings	$82,287		$82,287	$0	$82,287	50	2%	$1,646
1810	Leasehold Improvements	$0		$0	$0	$0			
1815	Transformer Station Equipment >5	$0		$0	$0	$0			
1820	Distribution Station Equipment <5	$663,461		$663,461	$26,423	$676,672	25	4%	$27,067
1820	Distribution Station Equipment <50 kV			$0		$0			
1825	Storage Battery Equipment			$0		$0			
1830	Poles, Towers & Fixtures	$427,684		$427,684	$24,408	$439,888	25	4%	$17,596
1835	Overhead Conductors & Devices	$1,744,680		$1,744,680	$49,751	$1,769,555	25	4%	$70,782
1840	Underground Conduit	$463,826		$463,826	$0	$463,826	25	4%	$18,553
1845	Underground Conductors & Device	$351,174		$351,174	$9,110	$355,729	25	4%	$14,229
1850	Line Transformers	$946,852		$946,852	$44,371	$969,038	25	4%	$38,762
1855	Services (Overhead and Undergrou	$244,898		$244,898	$16,739	$253,267	25	4%	$10,131
1860	Meters	$412,858		$412,858	$19,068	$422,392	25	4%	$16,896
1860	Meters (Smart Meters)			$0	$1,142,779	$571,390			$118,841
1905	Land			$0		$0			
1906	Land Rights			$0		$0			
1908	Buildings & Fixtures			$0		$0			
1910	Leasehold Improvements	$8,796		$8,796	$0	$8,796	10	10%	$880
1915	Office Furniture & Equipment (10 Years)			$0		$0			
1915	Office Furniture & Equipment (5 Years)			$0		$0			
1920	Computer Equipment - Hardware			$0		$0			
1920	Computer Equip. - Hardware (Post Mar. 22/04)			$0		$0			
1920	Computer Equip. - Hardware (Post	$151,383		$151,383	$2,305	$152,535			-$19,005
1925	Computer Software	$119,603		$119,603	$35,224	$137,215			$22,859
1930	Transportation Equipment	$289,161		$289,161	$37,935	$308,128			$41,496
1935	Stores Equipment			$0		$0			
1940	Tools, Shop & Garage Equipment	$129,209		$129,209	$3,775	$131,096	10	10%	$13,110
1945	Measurement & Testing Equipment			$0		$0			
1950	Power Operated Equipment			$0		$0			
1955	Communications Equipment			$0		$0			
1955	Communication Equipment (Smart Meters)			$0		$0			
1960	Miscellaneous Equipment			$0		$0			
1975	Load Management Controls Utility Premises			$0		$0			
1980	System Supervisor Equipment			$0		$0			
1985	Miscellaneous Fixed Assets			$0		$0			
1995	Contributions & Grants	-$360,988		-$360,988	$0	-$360,988	25	4%	-$14,440
etc.				$0		$0			
				$0		$0			
	Total	$5,759,089	$0	$5,759,089	$1,411,888	$6,465,033			$379,401

Table 4.14

2011 Depreciation and Amortization Expense (Appendix 2-M)

Account	Description	Opening Balance (a)	Less Fully Depreciated[1] (b)	Net for Depreciation (c) = (a) - (b)	Additions (d)	Total for Depreciation (e) = (c) + ½ x (d) [2]	Years (f)	Depreciation Rate (g) = 1 / (f)	Depreciation Expense (h) = (e) / (f)	Did Depreciation Rate in "g" Change (Yes/No)? [3]
1805	Land	$84,205		$84,205	$0	$84,205	-			
1808	Buildings	$82,287		$82,287	$0	$82,287	50.00	2.0%	$1,646	No
1810	Leasehold Improvements	$0		$0	$0	$0				
1815	Transformer Station Equipment >5	$0		$0	$0	$0				
1820	Distribution Station Equipment <5	$311,992		$311,992	$15,000	$319,492	25.00	4.0%	$12,780	No
1820	Distribution Station Equipment <5	$377,892		$377,892	$20,000	$387,892	45.00	2.2%	$8,620	Yes
1825	Storage Battery Equipment			$0		$0				
1830	Poles, Towers & Fixtures	$452,092		$452,092	$50,000	$477,092	45.00	2.2%	$10,602	Yes
1835	Overhead Conductors & Devices	$1,794,430		$1,794,430	$45,000	$1,816,930	60.00	1.7%	$30,282	Yes
1840	Underground Conduit	$36,862		$36,862	$0	$36,862	50.00	2.0%	$737	Yes
1845	Underground Conductors & Device	$787,248		$787,248	$10,000	$792,248	40.00	2.5%	$19,806	Yes
1850	Line Transformers	$991,223		$991,223	$40,000	$1,011,223	45.00	2.2%	$22,472	Yes
1855	Services (Overhead and Undergrou	$261,637		$261,637	$20,000	$271,637	60.00	1.7%	$4,527	Yes
1860	Meters	$431,926	$295,772	$136,155	$40,000	$156,155	25.00	4.0%	$6,246	No
1860	Meters (Smart Meters)	$1,142,779		$1,142,779	$151,311	$1,218,434			$101,874	
1905	Land			$0		$0				
1906	Land Rights			$0		$0				
1908	Buildings & Fixtures			$0		$0				
1910	Leasehold Improvements	$8,796		$8,796	$0	$8,796	10.00	10.0%	$880	No
1915	Office Furniture & Equipment (10 Years)			$0		$0				
1915	Office Furniture & Equipment (5 Years)			$0		$0				
1920	Computer Equipment - Hardware			$0		$0				
1920	Computer Equip. - Hardware (Post Mar. 22/04)			$0		$0				
1920	Computer Equip. - Hardware (Pos	$153,688	$85,524	$68,163	$10,000	$73,163	5.00	20.0%	$14,633	No
1925	Computer Software	$154,827	$11,546	$143,280	$10,000	$148,280	5.00	20.0%	$29,656	No
1930	Transportation Equipment	$327,095		$327,095	$300,000	$477,095			$63,937	No
1935	Stores Equipment			$0		$0				
1940	Tools, Shop & Garage Equipment	$132,984		$132,984	$5,000	$135,484	10.00	10.0%	$13,548	No
1945	Measurement & Testing Equipment			$0		$0				
1950	Power Operated Equipment			$0		$0				
1955	Communications Equipment			$0		$0				
1955	Communication Equipment (Smart Meters)			$0		$0				
1960	Miscellaneous Equipment			$0		$0				
1975	Load Management Controls Utility Premises			$0		$0				
1980	System Supervisor Equipment			$0		$0				
1985	Miscellaneous Fixed Assets			$0		$0				
1995	Contributions & Grants	-$360,988		-$360,988	$0	-$360,988	45.00	2.2%	-$8,022	Yes
etc.				$0		$0				
				$0		$0				
	Total	$7,170,977	$392,842	$6,778,134	$716,311	$7,136,290			$334,224	

Table 4.15

2012 Depreciation and Amortization Expense (Appendix 2-M)

Acct	Description	Opening Balance (a)	Less Fully Depreciated[1] (b)	Net for Depreciation (c) = (a) - (b)	Additions (d)	Total for Depreciation (e) = (c) + ½ x (d) [2]	Years (f)	Depreciation Rate (g) = 1 / (f)	Depreciation Expense (h) = (e) / (f)	Did Depreciation Rate in "g" Change (Yes/No)? [3]
1805	Land	$84,205		$84,205	$0	$84,205	-			
1808	Buildings	$82,287		$82,287	$7,690	$86,132	50.00	2.0%	$1,723	No
1810	Leasehold Improvements	$0		$0	$0	$0				
1815	Transformer Station Equipment >50 k	$0		$0	$0	$0				
1820	Distribution Station Equipment <50 k'	$326,992		$326,992	$15,000	$334,492	25.00	4.0%	$13,380	No
1820	Distribution Station Equipment <50 k'	$397,892		$397,892	$20,000	$407,892	45.00	2.2%	$9,064	Yes
1825	Storage Battery Equipment			$0		$0				
1830	Poles, Towers & Fixtures	$502,092		$502,092	$72,310	$538,247	45.00	2.2%	$11,961	Yes
1835	Overhead Conductors & Devices	$1,839,430		$1,839,430	$50,000	$1,864,430	60.00	1.7%	$31,074	Yes
1840	Underground Conduit	$36,862	$0	$36,862	$0	$36,862	50.00	2.0%	$737	Yes
1845	Underground Conductors & Devices	$797,248		$797,248	$20,000	$807,248	40.00	2.5%	$20,181	Yes
1850	Line Transformers	$1,031,223		$1,031,223	$60,000	$1,061,223	45.00	2.2%	$23,583	Yes
1855	Services (Overhead and Underground)	$281,637		$281,637	$20,000	$291,637	60.00	1.7%	$4,861	Yes
1860	Meters	$176,155		$176,155	$40,000	$196,155	25.00	4.0%	$7,846	Yes
1860	Meters (Smart Meters)	$1,294,090		$1,294,090	$0	$1,294,090			$110,121	
1905	Land			$0		$0				
1906	Land Rights			$0		$0				
1908	Buildings & Fixtures			$0		$0				
1910	Leasehold Improvements	$8,796		$8,796	$0	$8,796	10.00	10.0%	$880	No
1915	Office Furniture & Equipment (10 Years)			$0		$0				
1915	Office Furniture & Equipment (5 Years)			$0		$0				
1920	Computer Equipment - Hardware			$0		$0				
1920	Computer Equip. - Hardware (Post Mar. 22/04)			$0		$0				
1920	Computer Equip. - Hardware (Post M	$163,688	$92,556	$71,131	$20,000	$81,131	5.00	20.0%	$16,226	No
1925	Computer Software	$164,827	$11,546	$153,280	$50,000	$178,280	5.00	20.0%	$35,656	No
1930	Transportation Equipment	$627,095		$627,095	$0	$627,095			$78,387	No
1935	Stores Equipment			$0		$0				
1940	Tools, Shop & Garage Equipment	$137,984	$75,572	$62,412	$10,000	$67,412	10.00	10.0%	$6,741	No
1945	Measurement & Testing Equipment			$0		$0				
1950	Power Operated Equipment			$0		$0				
1955	Communications Equipment			$0		$0				
1955	Communication Equipment (Smart Meters)			$0		$0				
1960	Miscellaneous Equipment			$0		$0				
1975	Load Management Controls Utility Premises			$0		$0				
1980	System Supervisor Equipment			$0		$0				
1985	Miscellaneous Fixed Assets			$0		$0				
1995	Contributions & Grants	-$360,988		-$360,988	$0	-$360,988	45.00	2.2%	-$8,022	No
etc.				$0		$0				
				$0		$0				
	Total	$7,591,516	$179,675	$7,411,841	$385,000	$7,604,341			$364,399	

8.0 TAXES (PAYMENTS IN LIEU OF TAXES ("PILS"), CAPTIAL AND PROPERTY TAXES

RSL has completed the tax calculations as per page 32 Section 2.7.8 in the Filing Guidelines.

Table 4.16 below provides a summary of 2008 Actual, 2009 Actual, and 2010 Actual income taxes included in audited statements, 2011 Bridge Year estimate using current rates, and 2012 Test Year income taxes based on revised rates.

Table 4.16

Summary of Income Taxes

	2008	2009	2010	2011	2012
Accounting Net Income before Taxes	$237,811	$266,344	$206,587	-$247,369	$311,241
Additions:					
Amortization of Tangible Assets	$228,996	$277,765	$260,560	$334,223	$364,399
Deductions:					
Capital cost Allowance - Schedule 8	-$298,383	-$377,771	-$425,045	-$385,246	-$423,197
Taxable Income	$168,424	$166,338	$42,102	-$298,392	$252,443
Tax Rate	16.5%	16.5%	16.0%	15.5%	15.5%
Income Taxes	**$27,790**	**$27,446**	**$6,735**	**-$46,251**	**$39,129**
Other/Tax Adjustments					
Gain on Disposal	-$676				
Gain on Exchange of Investments	-$398	-$398			
Apprenticeship Tax Credit	-$2,829	-$4,608	$320		
Recovery of Corporate Minimum Tax	-$88	$6,266	-$2,204		
Provision for PILs	**$23,799**	**$28,706**	**$4,851**	**-$46,251**	**$39,129**

RSL's 2010 Federal and Provincial tax returns are included as Appendix 4B and 4C.

Capital Cost Allowance:

Tables 4.17 and 4.18 below are the Capital Cost Allowance continuity schedules for the 2011 Bridge year and for the 2012 Test Year.

Table 4.17

CCA Continuity Schedule – 2011 Bridge Year

Class	Class Description	UCC Prior Year Ending Balance	UCC Bridge Year Opening Balance	Additions	Dispositions	UCC Before 1/2 Yr Adjustment	1/2 Year Rule {1/2 Additions Less Disposals}	Reduced UCC	Rate %	CCA	UCC Ending Balance
1	Distribution System - 1988 to 22-Feb-2005	4,209,675	4,209,675	0	0	4,209,675	0	4,209,675	4%	168,387	4,041,288
2	Distribution System - pre 1988		0	0	0	0	0	0	6%	0	0
6	Buildings (No footings below ground)		0	0	0	0	0	0	10%	0	0
8	General Office/Stores Equip	36,486	36,486	5,000	0	41,486	2,500	38,986	20%	7,797	33,689
10	Computer Hardware/ Vehicles	210,496	210,496	310,000	0	520,496	155,000	365,496	30%	109,649	410,847
10.1	Certain Automobiles		0	0	0	0	0	0	30%	0	0
12	Computer Software	5,553	5,553	10,000	0	15,553	5,000	10,553	100%	10,553	5,000
3			0	0	0	0	0	0	5%	0	0
52			0	0	0	0	0	0		0	0
13 3	Lease # 3		0	0	0	0	0	0		0	0
13 4	Lease # 4		0	0	0	0	0	0		0	0
14	Franchise	3519	3,519	0	0	3,519	0	3,519		0	3,519
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs		0	0	0	0	0	0	8%	0	0
43.1	Certain Energy-Efficient Electrical Generating Equipment		0	0	0	0	0	0	30%	0	0
45	Computers & Systems Hardware acq'd post Mar 22/04	869	869	0	0	869	0	869	45%	391	478
50	Computers & Systems Hardware acq'd post Mar 19/07		0	0	0	0	0	0	55%	0	0
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)	1140	1,140	0	0	1,140	0	1,140	30%	342	798
47	Distribution System - post 22-Feb-2005	1,053,824	1,053,824	391,311	295,772	1,149,363	47,770	1,101,594	8%	88,127	1,061,236
	SUB-TOTAL - UCC	5,521,562	5,521,562	716,311	295,772	5,942,101	210,270	5,731,832		385,247	5,556,855

Table 4.18

CCA Continuity Schedule 2012 Test Year

Class	Class Description	UCC Prior Year Ending Balance	UCC Bridge Year Opening Balance	Additions	Dispositions	UCC Before 1/2 Yr Adjustment	1/2 Year Rule {1/2 Additions Less Disposals}	Reduced UCC	Rate %	CCA	UCC Ending Balance
1	Distribution System - 1988 to 22-Feb-2005	4,041,288	4,041,288	0	0	4,041,288	0	4,041,288	4%	161,652	3,879,636
2	Distribution System - pre 1988	0	0	0	0	0	0	0	6%	0	0
6	Buildings (No footings below ground)	0	0	0	0	0	0	0	10%	0	0
8	General Office/Stores Equip	33,689	33,689	10,000	0	43,689	5,000	38,689	20%	7,738	35,951
10	Computer Hardware/ Vehicles	410,847	410,847	20,000	0	430,847	10,000	420,847	30%	126,254	304,593
10.1	Certain Automobiles	0	0	0	0	0	0	0	30%	0	0
12	Computer Software	5,000	5,000	50,000	0	55,000	25,000	30,000	100%	30,000	25,000
3		0	0	0	0	0	0	0	5%	0	0
		0	0	0	0	0	0	0	0%	0	0
13 3	Lease # 3	0	0	0	0	0	0	0		0	0
13 4	Lease # 4	0	0	0	0	0	0	0		0	0
14	Franchise	3,519	3,519	0	0	3,519	0	3,519		0	3,519
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs	0	0	0	0	0	0	0	8%	0	0
43.1	Certain Energy-Efficient Electrical Generating Equipment	0	0	0	0	0	0	0	30%	0	0
45	Computers & Systems Hardware acq'd post Mar 22/04	478	478	0	0	478	0	478	45%	215	263
50	Computers & Systems Hardware acq'd post Mar 19/07	0	0	0	0	0	0	0	55%	0	0
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)	798	798	0	0	798	0	798	30%	239	559
47	Distribution System - post 22-Feb-2005	1,061,236	1,061,236	305,000	0	1,366,236	152,500	1,213,736	8%	97,099	1,269,137
	SUB-TOTAL - UCC	**5,556,855**	**5,556,855**	**385,000**	**0**	**5,941,855**	**192,500**	**5,749,355**		**423,197**	**5,518,658**

9.0 GREEN ENERGY ACT PLAN O&M COSTS

The Green Energy Act and the Boards EB-2009-0397 Filing Requirements of March 25, 2010, directed LDCs' to prepare and Green Energy Plan and submit the Plan to the OPA for review.

RSL submitted a "Basic Green Energy Act Plan" (Plan) to the Ontario Power Authority (OPA), and received comments/input from the OPA on August 29, 2011.

A copy of RSL's basic Plan, and the OPA's input are include with Exhibit 2, as Appendix A.

RSL has not included any O&M costs for Renewable Generation connection or Smart Grid development in its 2012 COS Rate Application.

10.0 CONSERVATION AND DEMAND MANAGEMENT ("CDM") COSTS

Section 27 of the Ontario Energy Board Act, 1998, allows the Minister of Energy and Infrastructure to issue a Minister's Directive to the Ontario Energy Board.

On March 31, 2010 the Minister issued a Ministers Directive to the Board, which directed the Board to amend the licenses of all licenses electricity distributors to include CDM targets.

The Boards Conservation and Demand Management Code for Electricity Distributors (CDM) was issued September 16, 2010, and sets out obligations and requirements in relation to CDM activities after December 31, 2010. The CDM code applies to programs that start January 1, 2011 and end on December 31, 2014, or occur anytime in between those dates.

On November 12, 2010 the Board issued its decision on EB-2010-0215 and EB-2010-0216 and Appendix A attached to that decision included LDC CDM targets. RSL's CDM target is a cumulative energy savings of 5.1 million kWh's, and an Annual Peak Demand Savings of 1,220 kW.

The Green Energy Act, amended the OEB Act by including section 78.5, that changes the way CDM programs are funded. Traditionally they were funded as part of distribution rates. Changes per Section 78.5, expect that Board-approved CDM programs will be funded by the OPA.

RSL has entered into contracts with the OPA to deliver the OPA Province-Wide CDM Programs.

RSL has not included any incremental OM&A costs for CDM in this Rate application. RSL has contracted with the OPA and third parties for the programs.

CONFIDENTIAL

MASTER SERVICES AGREEMENT

BETWEEN

RIDEAU ST. LAWRENCE UTILITIES INC.

AND

RIDEAU ST. LAWRENCE DISTRIBUTION INC.

MADE AS OF

MAY 26, 2004

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MASTER SERVICES AGREEMENT

MASTER SERVICES AGREEMENT

THIS AGREEMENT is made as of May 26, 2004

BETWEEN:

RIDEAU ST. LAWRENCE UTILITIES INC., a corporation incorporated under the laws of the Province of Ontario

(Hereinafter referred to as "RSL")

AND

RIDEAU ST. LAWRENCE DISTRIBUTION INC., a corporation incorporated under the laws of the Province of Ontario

(Hereinafter referred to as the "LDC")

THIS AGREEMENT WITNESSES that, in consideration of the covenants and agreements herein contained, the parties hereto agree as follows:

ARTICLE 1- GENERAL

1.01 Services

Subject to the terms and conditions hereof, the LDC shall retain RSL to carry out services and RSL shall render the following services to the LDC:

(a) Building maintenance including janitorial services, snow plowing, lawn care, major and minor repairs;

(b) Purchasing including procurements at best price, order tracking, delivery of operating and capital items, payment processing and vendor management;

(c) Stores management including maintaining stock levels at efficient levels, issuing and receiving, maintenance of inventory management system and disposition of excess assets;

(d) Safety monitoring including the development of policies and procedures, training (awareness and procedures), site inspections and field audits;

(e) Environmental compliance monitoring including the development of policies and procedures, training (awareness and procedures), regulatory reporting, government liaison and site inspections;

(f) Human resources administration including the development of policies and procedures, union relations and negotiations, personel file management and management of employee benefit plans;

(g) Bookkeeping including the provision of statutory financial and regulatory reporting, management reporting and financial systems administration;

(h) Payroll including the maintenance of payroll records and payroll system, calculation of pay and payroll deductions and facilitation of payroll payments;

(i) Fleet management including the maintenance of all vehicles in working condition, major and minor repairs, regulatory reporting and expense tracking;

(j) Financial management including adminstration, investments and debt management, internal audit services and development of financial and accounting policies and procedures;

(k) Tax administration including compliance, regulatory reporting, planning, audit reviews and exposure management;

(l) Information technology including provision of management systems, system hardware and support services, major and minor repairs, development and policies and procedures;

(m) Operation and management of the distribution system;

(n) Meter reading services (including verification, testing, approval, installation and removal services);

(o) Billing and Collection services;

(p) Line clearing services;

(q) Repair and Maintenance for the distribution lines and facilities;

(r) Regulatory reporting and compliance services;

(s) Energy efficiency services that are approved by the Ontario Energy Board (including Demand Side management programs);

(t) Customer Care services;

(u) Wholesale settlement services;

(v) Electronic Business Transaction services;

(w) RSL shall expand or upgrade in a timely and in a good and workmanlike manner the LDC's electrical distribution system at the LDC's request.

(x) Such other services as may from time to time be agreed upon between the parties

1.02 Term of Agreement

The provision of services by RSL to the LDC shall commence on May 26, 2004 and shall continue until terminated by the parties hereto as set forth in article 4 hereof.

ARTICLE 2 – REMUNERATION OF RSL

2.01 Fee for Services

The LDC shall pay to RSL for the services provided under this Agreement a fee at the rate of cost plus a reasonable rate of return as determined by the parties, provided that such fee for services at the above-noted rate shall be reviewed by the parties at the option of either party.

2.02 Expenses

RSL shall be responsible for all day-to-day expenses incurred in connection with the services to be provided pursuant to Section 1.01 hereof. However, the LDC shall reimburse RSL for all extraordinary expenses actually and properly incurred by RSL in the performance of the services hereunder provided that such expenses shall be paid in accordance with the normal practices of the LDC in force from time to time.

2.03 Invoices

Payment shall be made to RSL with respect to fees and expenses referred to in Sections 2.01 and 2.02 within 15 days from receipt by the LDC of proper invoices and vouchers, all of which shall be submitted by RSL to the LDC by the last day of the following month during the term of this Agreement. RSL shall also provide a report annually of all expenses incurred in connection with the provision of services pursuant to Section 1.01 hereof.

ARTICLE 3- COVENANTS OF RSL

3.01 Services

RSL shall render performance of the services hereunder to the best of RSL's ability in a competent and professional manner.

3.02 Time of Services

RSL shall devote such of its time and attention to the business of the LDC as may be agreed to the RSL and the LDC. The time of services to be provided hereunder by RSL shall be as agreed to from time to time by the LDC and RSL.

Subject to the obligations of RSL hereunder, RSL shall be free to offer services to any other person.

3.03 Licenses and Permits

RSL shall be responsible for obtaining all necessary licenses and permits and for complying with all applicable federal, provincial and municipal laws, codes and regulations in connection with the provision of the services hereunder and RSL shall when requested provide the LDC with adequate evidence of this compliance with this Section 3.03.

3.04 Rules and Regulations

RSL shall comply, while on the premises used by the LDC, with all the rules and regulations of the LDC from time to time in force, which are brought to its notice or of which it could reasonably be aware; and
the provision of services by RSL to the LDC will be in compliance with the distributor's license, the IMO market rules, the Distribution System Code, the Retail Settlement Code, Standard Supply Service Code and other such codes, rules and regulations which from time to time shall come into force.

3.05.1 Regulatory Compliance

RSL shall ensure that any order or measure made or taken by the Ontario Energy Board:

(i) that is brought to its attention or of which it becomes aware;

(ii) that is directed at or affects the LDC; and

(iii) that, in order to be implemented or complied with, is dependent in whole or in part upon any service or task that RSL is obligated to perform hereunder;

shall be fully implemented or complied with to the extent of RSL's obligations hereunder. In connection with this section, LDC agrees that it will promptly notify RSL of any order or measure of the Ontario Energy Board directed at or affecting LDC.

3.05.2

Nothing in this Agreement will prevent LDC from taking any steps, including without limitation using LDC's own resources or those of a third party, that are necessary to implement or comply with the distribution license, or any other applicable provisions of the Legislation, Regulations and Market Rules, or any order or measure made or taken by the Ontario Energy Board.

3.06 Insurance

RSL shall pay for and maintain for the benefit of RSL and the LDC, with insurers or through the appropriate government department and in an amount and in a form acceptable to the LDC, appropriate insurance concerning the operations and liabilities of RSL relevant to this Agreement including, without limiting the generality of the foregoing, worker's compensation and employment insurance in conformity with applicable statutory requirements in respect of any remuneration payable by RSL to any employees of RSL and public liability and property damage insurance.

3.07 Indemnity

RSL shall indemnify and save the LDC harmless from and against all claims, actions, losses, expenses, costs or damages of every nature and kind whatsoever which the LDC or its officers, employees or agents may suffer as a result of the negligence of RSL in the performance or non-performance of this Agreement.

3.08 Non-disclosure

RSL shall not (either during the term of this Agreement or at any time thereafter) disclose any information relating to the private or confidential affairs of the LDC or relating to any secrets of the LDC to any person other than with the consent of the LDC. RSL shall keep confidential all confidential consumer information obtained in the course of providing services to the LDC, except as otherwise required by applicable law.

3.09 Monitoring of Services

RSL shall provide to the LDC all information that the LDC requires so that the LDC can monitor the provision of the distribution services provided by RSL. RSL will also provide information as requested by the LDC which is required for the LDC in fulfillment of it's distribution license.

ARTICLE 4- TERMINATION

4.01 Termination by the LDC or RSL for Cause

The LDC or RSL may terminate this Agreement at any time in the event of the failure of the other party to comply with any of the provisions hereunder upon such other party being notified in writing by the party alleging such failure and failing to remedy such failure within 30 days of receiving such notice.

4.02 Termination by the LDC or RSL on Notice

The LDC or RSL may terminate this Agreement upon the giving of 60 days written notice to the other party. Notwithstanding the foregoing, the LDC may terminate this Agreement immediately upon paying to RSL 60 days fee for services in lieu of such notice.

4.03 Provisions which Operate Following Termination

Notwithstanding any termination of the Agreement for any reason whatsoever and with or without cause, the provisions of 3.06 and 3.07 and any other provisions of this Agreement necessary to give efficacy thereto shall continue in full force and effect following any such termination.

ARTILCE 5- ARBITRATION

5.01 Arbitration of Disputes

Any disputes arising between the parties relating to the interpretation of any provision of this Agreement or other matters which under the provisions of this Agreement are to be referred to arbitration shall be settled by arbitration in accordance with the provisions of Section 5.02

5.02 Appointment of Arbitrator and Arbitration Procedures

a) In the event of disagreement, litigation or dispute with respect to the interpretation, application or execution of one or the other of the provisions of this Agreement the parties hereto renounce their right to institute legal proceedings and undertake to submit such disagreement, litigation or dispute to the final decision pursuant to Arbitration in accordance with Schedule "A" hereto.

b) The fees and disbursements of the arbitrator shall be shared equally by the parties to this Agreement.

c) The arbitration provided for in this Agreement is subject to the provisions of the *Arbitration Act* (Ontario), to the extent that such provisions are not incompatible herewith.

ARICLE 6- INTERPRETATION AND ENFORCEMENT

6.01 Sections and Headings

The division of the Agreement into Articles and Sections and the insertion of headings are for the convenience of reference only and shall not affect the construction or interpretation of this Agreement. The terms "this Agreement", "hereof", hereunder", and similar expressions refer to this Agreement and not to any particular Article, Section or other portion hereof and include any agreement or instrument supplemental; or ancillary hereto. Unless something in the subject matter or context is inconsistent therewith, references herein to Articles and Sections are to Articles and Sections of this Agreement.

6.02 Extended Meanings

In this Agreement words importing the singular number only include the plural and vice versa, word importing any gender include all genders and words importing persons include individuals, partnerships, associations, trusts, unincorporated organizations and corporations and *vise versa*.

6.03 Benefit of Agreement

This Agreement shall endure to the benefit of and be binding upon successors and assigns of RSL and the LDC, respectively.

6.04 Entire Agreement

This Agreement constitutes the entire Agreement between the parties with respect to the subject matter hereof and cancels and supersedes any prior understandings and agreements between the parties hereto with respect thereto. There are no representations, warranties, forms, conditions, undertakings or collateral agreements, express implied or statutory between the parties other than as expressly set forth in this Agreement.

6.05 Amendments and Waivers

No amendment to this Agreement shall be valid or binding unless set forth in writing and duly executed by both of the parties hereto. No waiver of any breach of any term or provision of this Agreement shall be effective or binding unless made in writing and signed by the party purporting to give the same and, unless otherwise provided in the written waiver, shall be limited to the specific breach waived.

6.06 Assignment

Except as may be expressly provided in this Agreement, neither party hereto may assign his or its rights or obligations under this Agreement without the prior written consent of the other party hereto.

6.07 Severability

If any provision of this Agreement is determined to be invalid or unenforceable in whole or in part, such invalidity or unenforceability shall attach only to such provision or part thereof and the remaining part of such provision and all other provisions hereof shall continue in full force and effect.

6.08 Notices

Any demand, notice or other communication to be made or given in connection with this Agreement shall be made or given in writing and may be made or given by personel delivery or by registered mail addressed to the recipient as follows:

To RSL

985 Industrial Road
P.O. Box 699
Prescott, Ontario
K0E 1T0

Attention: Mr. Allan Beckstead

To The LDC

985 Industrial Road
P.O. Box 699
Prescott, Ontario
K0E 1T0

Attention: Mr. John Walsh

Or such other address or individual as may be designated by notice by either party to the other. Any demand, notice or other communication made or given by personal delivery shall be conclusively deemed to have been given on the day of actual delivery thereof and, if made or given by registered mail, on the 5'th day other than a Saturday, Sunday or statutory holiday in Ontario, following the deposit thereof in the mail. If the party giving any demand, notice or other communication knows or ought reasonably to know of any difficulties with the postal system which might affect the delivery of the mail, any such demand, notice or other communication shall not be mailed but shall be made or given by personel delivery.

6.09 Further Assurances

Each party must from time to time execute and deliver all such further documents and instruments and do all acts and things as the other party may reasonably require to effectively carry out or better evidence or perfect the full intent and meaning of this Agreement.

6.10 Governing Law

This Agreement shall be governed by and construed in accordance with the laws of the Province of Ontario and the laws of Canada applicable therein.

6.11 Attornment

For the purpose of all legal proceedings this Agreement shall be deemed to have been performed in the Province of Ontario and, subject to Article 5 of this Agreement, the courts of the Province of Ontario shall have jurisdiction to entertain any action arising under this Agreement. Subject to Article 5 of this Agreement, the LDC and RSL each hereby attorns to the jurisdiction of the courts of the Province of Ontario provided than nothing herein contained shall prevent the LDC from proceeding at its election against RSL in the courts of any other province or country.

IN WITNESS WHEREOF the parties have executed this Agreement.

RIDEAU ST. LAWRENCE UTILITIES INC.

Per: Allan Beckstead

Name: Allan Beckstead
Title: Chief Financial Officer

RIDEAU ST. LAWRENCE DISTRIBUTION INC.

Per: ______________________

Name: John Walsh
Title: Chief Executive Officer

SCHEDULE "A"

ARBITRATION

The parties agree to consult with each other and to negotiate in good faith to resolve any differences or disputes which either party may have relating to the interpretation, application or implementation of this agreement, or any dispute which may arise over any costs, fees or other costs incurred and failing agreement the parties agree to resolve their disputes by arbitration as provided in this Schedule "A" and the decision shall be final and binding as between the parties hereto and shall not be subject to appeal.

Arbitration of a dispute shall be commenced by written notice by a party requesting arbitration with the other, which notice shall identify the issue or issues it wished to submit to arbitration. Within thirty (30) days of the date of notice, the Parties shall agree upon a single arbitrator and failing agreement then each party shall appoint an arbitrator and the two appointees shall within forty-five (45) days of the date of notice of arbitration appoint a third person who shall act as Chair of the arbitration panel, and failing agreement the Chair shall be appointed by a judge of the Superior Court of Ontario pursuant to the provisions of the Arbitration's Act, RSO 1991 c.A.17.

The commencement of arbitration and all rules of procedure for the arbitration shall be by agreement of the Parties, or failing agreement, as determined by the arbitrator or Chair of the arbitrator panel. The provisions of the Arbitration's Act, RSO 1991 c.A.17, as amended or any successor legislation shall apply to the arbitration.

All decisions of the arbitrator or arbitrators, as the case may be, shall be made in writing and shall be delivered to all Parties within ten (10) days from the conclusion of the arbitration. All decisions shall be final and binding upon the Parties, their respective successors and assigns, and shall not be subject to appeal.

Each party shall pay its own costs incurred in respect of the arbitration including the payment of its appointee to the arbitration panel, and in the case of a three-person panel the parties agree to share the fees of the Chair and other related costs equally.

APPENDIX 4B

200

Canada Revenue Agency / Agence du revenu du Canada

T2 CORPORATION INCOME TAX RETURN

EXEMPT FROM TAX

055 Do not use this area

This form serves as a federal, provincial, and territorial corporation income tax return, unless the corporation is located in Quebec or Alberta. If the corporation is located in one of these provinces, you have to file a separate provincial corporation return.

Parts, sections, subsections, paragraphs, and subparagraphs mentioned on this return refer to the federal *Income Tax Act*. This return may contain changes that had not yet become law at the time of printing.

Send one completed copy of this return, including schedules and the *General Index of Financial Information* (GIFI), to your tax centre or tax services office. You have to file the return within six months after the end of the corporation's tax year.

For more information see **www.cra.gc.ca** or Guide T4012, *T2 Corporation – Income Tax Guide*.

CLIENT COPY

Identification

Business Number (BN) 001 86485 1993 RC0001

Corporation's name
002 Rideau St. Lawrence Distribution Inc.

Address of head office
Has this address changed since the last time you filed your T2 return? . . . . 010 1 Yes [ ] 2 No [X]
(If **yes**, complete lines 011 to 018.)
011 P.O. Box 699
012 985 Industrial Road

City	Province, territory, or state
015 Prescott	016 ON
Country (other than Canada) 017	Postal code/Zip code 018 K0E 1T0

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 [X]
(If **yes**, complete lines 021 to 028.)
021 c/o
022
023

City	Province, territory, or state
025	026
Country (other than Canada) 027	Postal code/Zip code 028

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 [X]
(If **yes**, complete lines 031 to 038.)
031 P.O. Box 699
032 985 Industrial Road

City	Province,territory, or state
035 Prescott	036 ON
Country (other than Canada) 037	Postal code/Zip code 038 K0E 1T0

040 Type of corporation at the end of the tax year

1 [X] Canadian-controlled private corporation (CCPC)
2 [ ] Other private corporation
3 [ ] Public corporation
4 [ ] Corporation controlled by a public corporation
5 [ ] Other corporation (specify, below)

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 060 2010-01-01 YYYY MM DD
Tax year-end 061 2010-12-31 YYYY MM DD

Has there been an acquisition of control to which subsection 249(4) applies since the previous tax year? . . . . 063 1 Yes [ ] 2 No [X]

If **yes**, provide the date control was acquired . . . . 065 ______ YYYY MM DD

Is the date on line 061 a deemed tax year-end in accordance with subsection 249(3.1)? . . . . 066 1 Yes [ ] 2 No [X]

Is the corporation a professional corporation that is a member of a partnership? . . . . 067 1 Yes [ ] 2 No [X]

Is this the first year of filing after:
Incorporation? . . . . 070 1 Yes [ ] 2 No [X]
Amalgamation? . . . . 071 1 Yes [ ] 2 No [X]
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 [X]
If **yes**, complete and attach Schedule 24.

Is this the final tax year before amalgamation? . . . . 076 1 Yes [ ] 2 No [X]

Is this the final return up to dissolution? . . . . 078 1 Yes [ ] 2 No [X]

If an election was made under section 261, state the functional currency used . . . . 079 ______

Is the corporation a resident of Canada?
080 1 Yes [X] 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 [X]
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 [X] 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?	150	X	9
Is the corporation an associated CCPC?	160	X	23
Is the corporation an associated CCPC that is claiming the expenditure limit?	161		49
Does the corporation have any non-resident shareholders?	151		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	162		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?	163		44
Has the corporation paid any royalties, management fees, or other similar payments to residents of Canada?	164		14
Is the corporation claiming a deduction for payments to a type of employee benefit plan?	165		15
Is the corporation claiming a loss or deduction from a tax shelter acquired after August 31, 1989?	166		T5004
Is the corporation a member of a partnership for which a partnership identification number has been assigned?	167		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?	168		22
Did the corporation have any foreign affiliates during the year?	169		25
Has the corporation made any payments to non-residents of Canada under subsections 202(1) and/or 105(1) of the federal *Income Tax Regulations*?	170		29
Has the corporation had any non-arm's length transactions with a non-resident?	171		T106
For private corporations: Does the corporation have any shareholders who own 10% or more of the corporation's common and/or preferred shares?	173	X	50
Has the corporation made payments to, or received amounts from, a retirement compensation plan arrangement during the year?	172		
Is the net income/loss shown on the financial statements different from the net income/loss for income tax purposes?	201	X	1
Has the corporation made any charitable donations; gifts to Canada, a province, or a territory; gifts of cultural or ecological property; or gifts of medicine?	202		2
Has the corporation received any dividends or paid any taxable dividends for purposes of the dividend refund?	203	X	3
Is the corporation claiming any type of losses?	204		4
Is the corporation claiming a provincial or territorial tax credit or does it have a permanent establishment in more than one jurisdiction?	205		5
Has the corporation realized any capital gains or incurred any capital losses during the tax year?	206		6
i) Is the corporation (or its associated corporations) 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) does the corporation have aggregate investment income at line 440?	207		7
Does the corporation have any property that is eligible for capital cost allowance?	208	X	8
Does the corporation have any property that is eligible capital property?	210		10
Does the corporation have any resource-related deductions?	212		12
Is the corporation claiming deductible reserves?	213		13
Is the corporation claiming a patronage dividend deduction?	216		16
Is the corporation a credit union claiming a deduction for allocations in proportion to borrowing or an additional deduction?	217		17
Is the corporation an investment corporation or a mutual fund corporation?	218		18
Is the corporation carrying on business in Canada as a non-resident corporation?	220		20
Is the corporation claiming any federal or provincial foreign tax credits, or any federal or provincial logging tax credits?	221		21
Does the corporation have any Canadian manufacturing and processing profits?	227		27
Is the corporation claiming an investment tax credit?	231		31
Is the corporation claiming any scientific research and experimental development (SR&ED) expenditures?	232		T661
Is the total taxable capital employed in Canada of the corporation and its related corporations over $10,000,000?	233		
Is the total taxable capital employed in Canada of the corporation and its associated corporations over $10,000,000?	234		
Is the corporation claiming a surtax credit?	237		37
Is the corporation subject to gross Part VI tax on capital of financial institutions?	238		38
Is the corporation claiming a Part I tax credit?	242		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?	243		43
Is the corporation agreeing to a transfer of the liability for Part VI.1 tax?	244		45
Is the corporation subject to Part II - Tobacco Manufacturers' surtax?	249		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?	250		39
Is the corporation claiming a Canadian film or video production tax credit refund?	253		T1131
Is the corporation claiming a film or video production services tax credit refund?	254		T1177
Is the corporation subject to Part XIII.1 tax? (Show your calculations on a sheet that you identify as Schedule 92.)	255		92

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
Did the corporation pay taxable dividends (other than capital gains dividends) in the tax year?	265	X	55
Has the corporation made an election under subsection 89(11) not to be a CCPC?	266		T2002
Has the corporation revoked any previous election made under subsection 89(11)?	267		T2002
Did the corporation (CCPC or deposit insurance corporation (DIC)) pay eligible dividends, or did its general rate income pool (GRIP) change in the tax year?	268		53
Did the corporation (other than a CCPC or DIC) pay eligible dividends, or did its low rate income pool (LRIP) change in the tax year?	269		54

Additional information

		1 Yes	2 No
Did the corporation use the International Financial Reporting Standards (IFRS) when it prepared its financial statements?	270		X
Is the corporation inactive?	280		X
Has the major business activity changed since the last return was filed? (enter **yes** for first-time filers)	281		X

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.

			%
284	Electricity Distribu	285	100.000 %
286		287	%
288		289	%

		1 Yes	2 No
Did the corporation immigrate to Canada during the tax year?	291		X
Did the corporation emigrate from Canada during the tax year?	292		X
Do you want to be considered as a quarterly instalment remitter if you are eligible?	293	X	

If the corporation was eligible to remit instalments on a quarterly basis for part of the tax year, provide the date the corporation ceased to be eligible **294** ______ (YYYY MM DD)

If the corporation's major business activity is construction, did you have any subcontractors during the tax year? **295** 1 Yes [ ] 2 No [ ]

Taxable income

Net income or (loss) for income tax purposes from Schedule 1, financial statements, or GIFI.	300		42,102	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			
Gifts of medicine from Schedule 2	315			
Taxable dividends deductible under section 112 or 113, or subsection 138(6) from Schedule 3	320			
Part VI.1 tax deduction*	325			
Non-capital losses of previous tax years from Schedule 4	331			
Net capital losses of previous tax years from Schedule 4	332			
Restricted farm losses of previous tax years from Schedule 4	333			
Farm losses of previous tax years from Schedule 4	334			
Limited partnership losses of previous 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			▶	B
Subtotal (amount A **minus** amount B) (if negative, enter "0")			42,102	C
Add: Section 110.5 additions or subparagraph 115(1)(a)(vii) additions	355			D
Taxable income (amount C **plus** amount D)	360		42,102	
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)				Z

* This amount is equal to 3.2 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** 42,102 A

Taxable income from line 360, **minus** 10/3 of the amount on line 632*, **minus** 1/(0.38 - X**) 3.57143 times the amount on line 636***, and **minus** any amount that, because of federal law, is exempt form Part I tax . . . . **405** ______ B

Calculation of the business limit:

For all CCPCs, calculate the amount at line 4 below.

400,000	x	Number of days in the tax year before 2009 / Number of days in the tax year	/ 365	=		1
500,000	x	Number of days in the tax year after 2008 / Number of days in the tax year	365 / 365	=	500,000	2
				Add amounts at lines 1 and 2	500,000	4

Business limit (see notes 1 and 2 below) . . . . **410** 425,000 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 425,000 x **415** **** ______ / 11,250 D = ... ______ E

Reduced business limit (amount C **minus** amount E) (if negative, enter "0") . . . . . . **425** 425,000 F

Small business deduction

Amount A, B, C, or F, whichever is the least ______ x 17 % = ... **430** ______ G

Enter amount G on line 1.

* 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.

** General rate reduction percentage for the tax year. It has to be pro-rated.

*** 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 previous tax years, the amount to be entered on 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 previous tax year, the amount to be entered on 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.

General tax reduction for Canadian-controlled private corporations

Canadian-controlled private corporations throughout the tax year

Taxable income from line 360			A
Lesser of amounts V and Y (line Z1) from Part 9 of Schedule 27		B	
Amount QQ from Part 13 of Schedule 27		C	
Amount used to calculate the credit union deduction from Schedule 17		D	
Amount from line 400, 405, 410, or 425, whichever is the least		E	
Aggregate investment income from line 440*		F	
Total of amounts B to F		▶	G
Amount A **minus** amount G (if negative, enter "0")			H

Amount H		x	Number of days in the tax year after December 31, 2007, and before January 1, 2009 / Number of days in the tax year	/ 365	x	8.5 %	=	I
Amount H		x	Number of days in the tax year after December 31, 2008, and before January 1, 2010 / Number of days in the tax year	/ 365	x	9 %	=	J
Amount H		x	Number of days in the tax year after December 31, 2009, and before January 1, 2011 / Number of days in the tax year	365 / 365	x	10 %	=	K
Amount H		x	Number of days in the tax year after December 31, 2010, and before January 1, 2012 / Number of days in the tax year	/ 365	x	11.5 %	=	L
Amount H		x	Number of days in the tax year after 2011 / Number of days in the tax year	/ 365	x	13 %	=	L.1

General tax reduction for Canadian-controlled private corporations – Total of amounts I to L.1 .... M

Enter amount M on line 638.

* Except for a corporation that is, throughout the year, a cooperative corporation (within the meaning assigned by subsection 136(2)) or a credit union.

General tax reduction

Do not complete this area if you are a Canadian-controlled private corporation, an investment corporation, a mortgage investment corporation, a mutual fund corporation, or any corporation with taxable income that is not subject to the corporation tax rate of 38%.

Taxable income from page 3 (line 360 or amount Z, whichever applies)			N
Lesser of amounts V and Y (line Z1) from Part 9 of Schedule 27		O	
Amount QQ from Part 13 of Schedule 27		P	
Amount used to calculate the credit union deduction from Schedule 17		Q	
Total of amounts O to Q		▶	R
Amount N **minus** amount R (if negative, enter "0")			S

Amount S		x	Number of days in the tax year after December 31, 2007, and before January 1, 2009 / Number of days in the tax year	/ 365	x	8.5 %	=	T
Amount S		x	Number of days in the tax year after December 31, 2008, and before January 1, 2010 / Number of days in the tax year	/ 365	x	9 %	=	U
Amount S		x	Number of days in the tax year after December 31, 2009, and before January 1, 2011 / Number of days in the tax year	365 / 365	x	10 %	=	V
Amount S		x	Number of days in the tax year after December 31, 2010, and before January 2012 / Number of days in the tax year	/ 365	x	11.5 %	=	W
Amount S		x	Number of days in the tax year after 2011 / Number of days in the tax year	/ 365	x	13 %	=	W.1

General tax reduction – Total of amounts T to W.1 X

Enter amount X on line 639.

Refundable portion of Part I tax

Canadian-controlled private corporations throughout the tax year

Aggregate investment income from Schedule 7	**440** ________ x 26 2 / 3 % =			A
Foreign non-business income tax credit from line 632		________		
Deduct: Foreign investment income from Schedule 7	**445** ________ x 9 1 / 3 % =	________		
	(if negative, enter "0")	________	► ________	B
Amount A **minus** amount B (if negative, enter "0")			________	C
Taxable income from line 360		42,102		
Deduct:				
Amount from 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 1(0.38 - X*) / 3.57143 =	________			
	________ ►	________		
		42,102		
		x 26 2 / 3 % =	11,227	D
Part I tax payable minus investment tax credit refund (line 700 **minus** line 780)			________	E
Refundable portion of Part I tax – Amount C, D, or E, whichever is the least		**450**	________	F

* General rate reduction percentage for the tax year. It has to be pro-rated.

Refundable dividend tax on hand

Refundable dividend tax on hand at the end of the previous tax year	**460**	________		
Deduct: Dividend refund for the previous tax year	**465**	________		
		________	► ________	G
Add the total of:				
Refundable portion of Part I tax from line 450 above		________		
Total Part IV tax payable from 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	130,000 x 1 / 3	43,333	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 – Taxable income (line 360 or amount Z, whichever applies) **multiplied** by 38 %			550	A
Recapture of investment tax credit from Schedule 31			602	B

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	42,102		
Deduct:			
Amount from line 400, 405, 410, or 425, whichever is the least			
Net amount	42,102 ▶	42,102	ii

Refundable tax on CCPC's investment income – 6 2 / 3 % of whichever is less: amount i or ii	604		C
Subtotal (**add** lines A to C)			D

Deduct:

Small business deduction from line 430			1
Federal tax abatement	608		
Manufacturing and processing profits deduction from Schedule 27	616		
Investment corporation deduction	620		
Taxed capital gains 624			
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		
General tax reduction for CCPCs from amount M	638		
General tax reduction from amount X	639		
Federal logging tax credit from Schedule 21	640		
Federal qualifying environmental trust tax credit	648		
Investment tax credit from Schedule 31	652		
Subtotal		▶	E

Part I tax payable – Line D **minus** line E ______ F
Enter amount F on line 700.

Summary of tax and credits

Federal tax

Part I tax payable	700	
Part II surtax payable from Schedule 46	708	
Part III.1 tax payable from Schedule 55	710	
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	
Total federal tax		

Add provincial or territorial tax:

Provincial or territorial jurisdiction . . . 750 ON
(if more than one jurisdiction, enter "multiple" and complete Schedule 5)

Net provincial or territorial tax payable (except Quebec and Alberta)	760	
Provincial tax on large corporations (New Brunswick* and Nova Scotia)	765	
Total tax payable	770	A

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	
Provincial and territorial capital gains refund from Schedule 18	808	
Provincial and territorial refundable tax credits from Schedule 5	812	
Tax instalments paid	840	
Total credits	890	B

Balance (line A **minus** line B)

Refund code 894 1 Overpayment

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

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 Branch number

914 Institution number

918 Account number

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 [X] 2 No [ ]

* The New Brunswick tax on large corporations is eliminated effective January 1, 2009.

Certification

I, 950 BECKSTEAD (Last name in block letters) 951 ALLAN (First name in block letters) 954 CFO (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 2011-06-23 (Date (yyyy/mm/dd))

Signature of the authorized signing officer of the corporation

956 (613) 925-3851 (Telephone number)

Is the contact person the same as the authorized signing officer? If **no**, complete the information below . . . 957 1 Yes [X] 2 No [ ]

958 Name in block letters

959 Telephone number

Language of correspondence – Langue de correspondance

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.

990 1

SCHEDULE 100

Canada Revenue Agency | Agence du revenu du Canada

GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Form identifier 100

Name of corporation	Business Number	Tax year end Year Month Day
Rideau St. Lawrence Distribution Inc.	86485 1993 RC0001	2010-12-31

Balance sheet information

Account	Description	GIFI		Current year	Prior year
	Assets				
	Total current assets	1599	+	3,253,139	2,928,818
	Total tangible capital assets	2008	+	6,028,198	5,759,090
	Total accumulated amortization of tangible capital assets	2009	–	1,904,542	1,643,984
	Total intangible capital assets	2178	+		
	Total accumulated amortization of intangible capital assets	2179	–		
	Total long-term assets	2589	+	478,190	1,165,899
	* Assets held in trust	2590	+		
	Total assets (mandatory field)	2599	=	7,854,985	8,209,823
	Liabilities				
	Total current liabilities	3139	+	1,860,182	3,101,635
	Total long-term liabilities	3450	+	2,443,359	1,628,480
	* Subordinated debt	3460	+		
	* Amounts held in trust	3470	+		
	Total liabilities (mandatory field)	3499	=	4,303,541	4,730,115
	Shareholder equity				
	Total shareholder equity (mandatory field)	3620	+	3,551,444	3,479,708
	Total liabilities and shareholder equity	3640	=	7,854,985	8,209,823
	Retained earnings				
	Retained earnings/deficit – end (mandatory field)	3849	=	1,040,321	968,585

* Generic item

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 125

Form identifier 125

GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Name of corporation	Business Number	Tax year end Year Month Day
Rideau St. Lawrence Distribution Inc.	86485 1993 RC0001	2010-12-31

Income statement information

Description	GIFI	
Operating name	0001	
Description of the operation	0002	
Sequence Number	0003	01

Account	Description	GIFI		Current year	Prior year
	Income statement information				
	Total sales of goods and services	8089	+	11,108,483	10,962,543
	Cost of sales	8518	–	9,131,849	8,978,754
	Gross profit/loss	8519	=	1,976,634	1,983,789
	Cost of sales	8518	+	9,131,849	8,978,754
	Total operating expenses	9367	+	2,019,057	1,998,432
	Total expenses (mandatory field)	9368	=	11,150,906	10,977,186
	Total revenue (mandatory field)	8299	+	11,357,493	11,243,530
	Total expenses (mandatory field)	9368	–	11,150,906	10,977,186
	Net non-farming income	9369	=	206,587	266,344
	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	=	206,587	266,344
	Total other comprehensive income	9998	=		
	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	–	4,851	28,706
	Deferred income tax provision	9995	–		
	Total – Other comprehensive income	9998	+		
	Net income/loss after taxes and extraordinary items (mandatory field)	9999	=	201,736	237,638

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 141

NOTES CHECKLIST

Corporation's name	Business Number	Tax year-end Year Month Day
Rideau St. Lawrence Distribution Inc.	86485 1993 RC0001	2010-12-31

- Parts 1, 2, and 3 of this schedule must be completed from the perspective of the person (referred to in these parts as the "accountant") who prepared or reported on the financial statements.
- For more information, see Guide RC4088, *General Index of Financial Information (GIFI) for Corporations* and Guide T4012, *T2 Corporation – Income Tax Guide*.
- Complete this schedule, and include it with your T2 return along with the other GIFI schedules.

If the person preparing the tax return is not the accountant referred to above, they must still complete Parts 1, 2, 3, and 4, as applicable.

Part 1 – Information on the accountant preparing or reporting on the financial statements

Does the accountant have a professional designation? . . . . . **095** 1 Yes [X] 2 No [ ]

Is the accountant connected* with the corporation? . . . . . **097** 1 Yes [ ] 2 No [X]

* 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 accountant does not have a professional designation **or** is connected to the corporation, you do not have to complete Parts 2 and 3 of this schedule. However, you do have to complete Part 4, as applicable.

Part 2 – Type of involvement with the financial statements

Choose the option that represents the highest level of involvement of the accountant: **198**

Completed an auditor's report . . . . . 1 [X]

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 with the financial statements** above, answer the following question:

Has the accountant expressed a reservation? . . . . . **099** 1 Yes [ ] 2 No [X]

Part 4 – Other information

If you have a professional designation and are not the accountant associated with the financial statements in Part 1 above, choose one of the following options: **110**

Prepared the tax return (financial statements prepared by client) . . . . . 1 [ ]

Prepared the tax return and the financial information contained therein (financial statements have not been prepared) . . . . . 2 [ ]

Were notes to the financial statements prepared? . . . . . **101** 1 Yes [X] 2 No [ ]

If **yes**, complete lines 102 to 107 below:

Are any values presented at other than cost? . . . . . **102** 1 Yes [ ] 2 No [X]

Has there been a change in accounting policies since the last return? . . . . . **103** 1 Yes [ ] 2 No [X]

Are subsequent events mentioned in the notes? . . . . . **104** 1 Yes [ ] 2 No [X]

Is re-evaluation of asset information mentioned in the notes? . . . . . **105** 1 Yes [ ] 2 No [X]

Is contingent liability information mentioned in the notes? . . . . . **106** 1 Yes [ ] 2 No [X]

Is information regarding commitments mentioned in the notes? . . . . . **107** 1 Yes [X] 2 No [ ]

Does the corporation have investments in joint venture(s) or partnership(s)? . . . . . **108** 1 Yes [ ] 2 No [X]

If **yes**, complete line 109 below:

Are you filing financial statements of the joint venture(s) or partnership(s)? . . . . . **109** 1 Yes [ ] 2 No [ ]

T2 BAR CODE RETURN

Name: Rideau St. Lawrence Distribution Inc.

BN: 86485 1993 RC 0001

Tax Year Start: 2010-01-01

Tax Year End: 2010-12-31

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

The corporation follows Canadian generally accepted accounting principles for electrical utilities prescribed in the Ontario Energy Board's Accounting Procedures Handbook under the authority of Acts of the Province of Ontario and permitted by the Ontario Energy Board.

(a) Revenue recognition

Revenue from the sale of electricity is recorded when billed. Unbilled revenue is the accrual for electricity sold between the last billing date and the year end date. The unbilled revenue adjustment is the change between the opening and closing balances of unbilled revenue and is included in revenue. Other income is recorded when services have been provided.

(b) Investments

Investments are recorded at lower of cost and market.

(c) Inventory

Inventory is valued at the lower of cost and net realizable value. Inventory is recorded using the average cost method.

(d) Capital assets and amortization

Capital assets are stated at acquisition cost and amortized using the straight line method over five to forty years.

(e) Construction in progress

Capital items purchased for capital projects under construction are included in construction in progress and are not amortized until put into service.

(f) Contributions and grants in aid of construction

Contributions and grants received in aid of construction are recorded as a deduction against capital assets. The amount is amortized on the same basis as the asset constructed and credited to amortization expense. No amortization is recorded until the asset is in use.

(g) Customer deposits

Deposits taken to guarantee the payment of power bills or contract performance are shown as a current or long term liability depending on the terms of repayment.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

(h) Use of estimates

The preparation of financial statements in conformity with Canadian generally accepted accounting principles 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 revenues and expenditures during the period. Actual results could differ from these estimates.

(i) Net regulatory assets and liabilities

The Ontario Energy Board provided accounting guidelines to include or exclude costs, revenues, losses or gains in the rates of a specific period, resulting in accounting recognition that differs from an unregulated company under Canadian generally accepted accounting principles. Such differences involves the application of rate regulated accounting resulting in the recognition of regulatory assets and liabilities. Regulatory assets represent certain amounts receivable from future customers and costs that have been deferred for accounting purposes that are expected be recovered in future rates. Any regulatory liabilities represents funds received in different periods that have been deferred for accounting purposes that are expected to be adjusted in future rates or recognize as revenue in future periods. The corporation continually assess the likelihood of recovery of each of its regulatory assets and liabilities into the setting of future rates. If the corporation determines that these regulatory assets and liabilities will no longer form as part of future rates, the appropriate carrying amount would be included in the results of operations in the period that the assessment is made. Description of regulatory assets is as follows:

(i) Retail settlement variance accounts

Retail settlement variance accounts are the net of sales and expenses incurred by the corporation for retail settlement after the commencement of market opening on May 1, 2002. The net sales and expenses are to be recovered through future rate increases, under Article 490 of the Ontario Energy Board Accounting Procedures Handbook. A return of capital is capitalized on these amounts based on Article 490.

(ii) Smart meter capital cost variance account

Smart meter capital cost variance account is the net of smart meter capital expenses and related incremental operating, maintenance, amortization and administration expenses incurred by the corporation less accumulated billings to offset those costs. The net expenses are to be recovered through future rate increases under Article 490 of the Ontario Energy Board Accounting Procedures Handbook. A return of capital is capitalized on these amounts based on Article 490.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

(j) Corporate income and capital taxes

Under the Electricity Act, 1998, the corporation is required to make payments in lieu of corporate taxes to the Ontario Energy Finance corporation. These payments are calculated in accordance with the rules of computing income and taxable capital and other relevant amounts contained in the Income Tax Act (Canada) and the Corporation Tax Act (Ontario) as modified by the Electricity Act, 1998, and related regulations.

The corporation provides for payments in lieu of corporate income taxes relating to its regulated businesses using the taxes payable method as directed by the Ontario Energy Board. 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. When recorded future income taxes become payable, it is expected that they will be included in the rates approved by the Ontario Energy Board and recovered from the customers of the corporation at that time.

(k) Financial instruments

(i) Fair value of financial instruments

CICA Handbook Section 3855 establishes standards for recognizing and measuring financial assets, financial liabilities and derivatives. This standard prescribes when to recognize a financial instrument in the balance sheet and at what amount. Depending on the classification, fair value or cost based measures are used. The standard also prescribes the basis of presentation for gains and losses on financial instruments. Based on financial instrument classification, gains and losses on financial instruments are recognized in net income or as other comprehensive income.

The corporation has made the following classifications:

(i) Cash and investments are classified as "held for trading." They are measured at fair value and any gains or losses resulting from the re measurement at end of each period are recognized in net income.

(ii) Accounts receivable and unbilled revenue are classified as "loans and receivables." They are recorded at cost, which upon their initial measurement is equal to their fair value. Subsequent measurements are recorded at amortized cost using the effective interest method.

(iii) Accounts payables and customer deposits are classified as "financial liabilities." They are recorded at their cost which upon their initial measurement is equal to their fair value. Subsequent measurements are recorded at amortized cost using the effective interest method.

The carrying amounts reported on the balance sheet for cash, investments, accounts receivable, unbilled revenue, accounts payable and customer deposits, approximate fair values due to the immediate and short term maturities of these financial instruments.

The fair value of long term debt, including the current portion, is based on rates currently available to the corporation with similar terms and maturities and approximates its carrying amounts as disclosed on the balance sheet.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

(k) Financial instruments (continued)

(ii) Concentration of credit risk

The corporation does not believe it is subject to any significant concentration of credit risk. Cash is in place with major financial institutions. Accounts receivable are the result of sales to individuals, corporations and not for profit organizations geographically concentrated within Eastern Ontario.

(iii) Comprehensive income Section 1530

This Section describes the recognition and disclosure requirements with respect to comprehensive income. Comprehensive income consists of net income and other comprehensive income. Other comprehensive income represents the changes in the fair value of financial instruments which have not been included in net income. As the corporation did not have any adjustments to other comprehensive income during the year, this standard does not have an impact on the financial statements.

(l) International Financial Reporting Standards ("IFRS")

The Canadian Institute of Chartered Accountants announced that Canadian publicly accountable enterprises will be required to adopt International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("ISAB"), effective January 1, 2011. On September 10, 2010, the Canadian Accounting Standards Board ("AcSB") decided to permit rate regulated entities to defer their IFRS implementation date to January 1, 2012. As such, the corporation will apply IFRS to its financial statements commencing January 1, 2012 with restatement of the amounts recorded on the opening IFRS balance sheet as at January 1, 2011 for comparative purposes. While the corporation is currently developing an implementation plan for the adoption of IFRS, the financial reporting impact of the transition to IFRS cannot be reasonably estimated at this time.

2. INVESTMENTS

The corporation exchanged its ownership of 18,000 units with a zero carrying value of Enerconnect Limited Partnership for 12,067 shares of Utilismart Corporation in December 2007. The shares of Utilismart Corporation are to be distributed to the corporation over a three year period. The corporation received no shares during the year for an accounting gain of $ (2009 $2,414).

3. CAPITAL

	Cost	Accumulated Amortization	Net 2010	Net 2009
Land	$ 84,205	$ -	$ 84,205	$ 84,205
Buildings, leasehold improvements and fixtures	91,084	8,847	82,237	84,762
Distribution equipment	5,772,398	1,702,991	4,069,407	4,097,113
Tools and equipment	132,984	97,597	35,387	44,721
Computer hardware and software	308,514	175,098	133,416	99,741
Less: Contributions in aid of construction	(360,987)	(79,991)	(280,996)	(295,436)
	$ 6,028,198	$ 1,904,542	$ 4,123,656	$ 4,115,106

4. NET REGULATORY ASSETS

	2010	2009
Retail settlement variance accounts	$ (468,978)	$ 346,371

Smart meter capital cost variance account 1,159,503

819,528

Smart meter funding (212,335) -

$ 478,190 $ 1,165,899

The Ontario Energy Board approved billing rates for the recovery of smart meter capital costs on a non prudential basis of $2.00 per customer per month in 2010. The corporation will be applying for full cost recovery of the smart meter capital costs in future rate applications through the Ontario Energy Board.

5. TEMPORARY ADVANCES

	2010	2009
Demand loan	$ -	$ 833,403
Demand loan	-	245,000
	$ -	$ 1,078,403

Demand loans are non revolving loans that bear interest at prime, interest only payments for first twelve months, maximum borrowing limit of $1,695,000 and are secured by a general security agreement dated May 20, 2009.

The corporation has an overdraft lending facility up to $750,000 that was not utilized as of December 31, 2010 with the same terms and conditions as the demand loans indicated in Note 6. The consolidated corporation provided a guarantee for the indebtedness up to $2,445,000 dated July 8, 2009.

6. CALLABLE DEBT

2010 2009

Demand loan, interest at prime, monthly payments of $6,945 plus interest,

$ 791,733 $ -

due on demand, secured by equipment and general security agreement

Demand loan, interest at prime, monthly payments of $2,553 plus interest,

214,375 -

due on demand, secured by vehicle and general security agreement

1,006,108 -

Less: current portion 113,965 -

$ 892,143 $ -

The repayment of callable debt is as follows:

2011 $ 113,965

2012 113,965

2013 113,965

2014 113,965

2015 113,965

Thereafter 436,283

$ 1,006,108

The demand loans are classified as callable debt obligations where the lender has or retains the right to demand full payment of the obligation over the course of the loans. These amounts would not be repaid within one year unless the lender exercises their right to demand payment in full.

7. REGULATORY LIABILITIES

Regulatory liabilities represents funds received for the transfer of Hydro One low voltage regulatory assets and the Conservation and Demand Management (C&DM) program. Costs are recorded against these funds when incurred.

Transactions are summarized as follows:

Hydro One

Low Voltage C&DM

Transfer Program 2010 2009

Balance, beginning of year $ - $ - $ -

$ 19,314

Transfer of regulatory liabilities - - -

38,718

Disbursements against regulatory liabilities - -

- (43,524)

Balance, end of year $ - $ - $ - $

14,508

8. ADVANCES FROM RELATED PARTIES

2010 2009

Advances from Rideau St. Lawrence Utilities Inc. $ 248,383 $

302,030

Advances from Rideau St. Lawrence Services Inc. 13,702

9,482

$ 262,085 $ 311,512

The corporation is related to Rideau St. Lawrence Holdings Inc., Rideau St. Lawrence Utilities Inc., and Rideau St. Lawrence Services Inc. through common ownership. The corporation is a wholly owned subsidiary of Rideau St. Lawrence Holdings Inc.

During the year, the corporation incurred administration, maintenance and other service expenditures with Rideau St. Lawrence Utilities Inc. Terms and conditions of transactions with Rideau St. Lawrence Utilities Inc. are covered by a Master Services Agreement dated November 1, 2000. Under this agreement, Rideau St. Lawrence Utilities Inc. provides specified services to the corporation on a fee for services basis.

9. LONG TERM DEBT

2010 2009

Loan payable, interest at 4.99%, payable in blended monthly payments $

70,940 $ 188,470

of $10,096, due July 2011, secured by specific assets

Promissory note, Corporation of the Township of Edwardsburgh/Cardinal

225,000 225,000

Promissory note, Corporation of the Township of South Dundas 938,352

938,352

1,234,292 1,351,822

Less: current portion 70,940 117,500

$ 1,163,352 $ 1,234,322

The promissory notes bear interest at a rate determined by the Board of Directors not to exceed 7.25% per annum and are unsecured. Principal and interest shall be payable at the discretion of the Board of Directors.

Interest rate at December 31, 2010 is 4.99%. The repayment of long term debt is as follows:

2011 $ 70,940

Thereafter 1,163,352

$ 1,234,292

10. ADVANCES FROM RELATED PARTY

Advances from related party are from Rideau St. Lawrence Holdings Inc., which bears no interest, has no specific terms of repayment, and are unsecured.

11. CAPITAL STOCK

Authorized

Unlimited common shares

2010 2009

Issued

2,511,123 common shares $ 2,511,123 $ 2,511,123

12. PAYMENTS IN LIEU OF CORPORATE TAXATION

The provision for payments in lieu of corporate income taxes (PIL's) differs from the amount that would have been recorded using the combined Canadian Federal and Ontario statutory income tax rate. A reconciliation between the statutory and effective tax rates is provided as follows:

2010 2009

Income before PIL's $ 206,587 $ 266,344

Federal and Ontario statutory income tax rates 16.00%

16.50%

PIL's at statutory rate 33,054 43,947

Decrease resulting from:

Temporary differences:

Capital cost allowance in excess of amortization (26,319)

(16,501)

Accounting gain on exchange of investments - (398)

Net temporary differences (26,319) (16,899)

Permanent differences:

Corporate Minimum Tax (recovery) (2,204) 6,266

Federal and Ontario Apprenticeship Training Tax Credits, net of tax

320 (4,608)

Net permanent differences (1,884) 1,658

Provision for PIL's $ 4,851 $ 28,706

Effective income tax rate 2.35% 10.78%

As at December 31, 2010, future income tax assets of $237,000 (2009 $198,000), based on current income tax rates, have not been recorded.

13. CONTINGENCIES

The corporation entered into an irrevocable standing letter of credit with a financial institution. The letter of credit is a prudential support obligation required by all small distribution companies in Ontario for the Independent Electricity System Operator (IESO). The prudential support obligation is calculated at $681,809 which the corporation has not exercised as of December 31, 2010.

A class action lawsuit was filed against the corporation and other local electric distribution companies in Ontario by customers who were charged late payment penalties. A settlement was made in July 2010. The corporation's share of the lawsuit settlement is $18,392. This amount has been recorded as accounts payable in these financial statements. The corporation will be recovering these costs over a one year period staring May 1, 2011 as part of its rate base as approved by the Ontario Energy Board.

SCHEDULE 100

GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Form identifier 100

Name of corporation	Business Number	Tax year-end Year Month Day
Rideau St. Lawrence Distribution Inc.	86485 1993 RC0001	2010-12-31

Assets – lines 1000 to 2599

1000	661,035	1060	946,900	1066	19,932
1120	221,106	1180	8,447	1480	1,371,719
1484	24,000	1599	3,253,139	1600	84,205
1680	91,084	1681	-8,847	1740	5,544,395
1741	-1,720,597	1774	308,514	1775	-175,098
2008	6,028,198	2009	-1,904,542	2424	478,190
2589	478,190	2599	7,854,985		

Liabilities – lines 2600 to 3499

2620	1,334,192	2863	262,085	2920	184,905
2961	79,000	3139	1,860,182	3140	2,055,495
3300	343,031	3320	44,833	3450	2,443,359
3499	4,303,541				

Shareholder equity – lines 3500 to 3640

3500	2,511,123	3600	1,040,321	3620	3,551,444
3640	7,854,985				

Retained earnings – lines 3660 to 3849

3660	968,585	3680	201,736	3701	-130,000
3849	1,040,321				

SCHEDULE 125

GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Form identifier 125

Name of corporation	Business Number	Tax year-end Year Month Day
Rideau St. Lawrence Distribution Inc.	86485 1993 RC0001	2010-12-31

Revenue – lines 8000 to 8299

8000	11,108,483	8089	11,108,483	8090	8,573
8140	59,022	8230	181,415	8299	11,357,493

Cost of sales – lines 8300 to 8519

8320	9,131,849	8518	9,131,849	8519	1,976,634

Operating expenses – lines 8520 to 9369

8670	260,560	8710	100,180	8810	710,501
9010	524,711	9270	423,105	9367	2,019,057
9368	11,150,906	9369	206,587		

Farming revenue – lines 9370 to 9659

9659	0

Farming expenses – lines 9660 to 9899

9898	0

Extraordinary items and taxes – lines 9970 to 9999

9970	206,587	9990	4,851	9999	201,736

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NET INCOME (LOSS) FOR INCOME TAX PURPOSES

SCHEDULE 1

Corporation's name	Business Number	Tax year end Year Month Day
Rideau St. Lawrence Distribution Inc.	86485 1993 RC0001	2010-12-31

- 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*.
- Sections, subsections, and paragraphs referred to on this schedule are from the *Income Tax Act*.

Amount calculated on line 9999 from Schedule 125			201,736 A
Add:			
Provision for income taxes – current	101	4,851	
Amortization of tangible assets	104	260,560	
Subtotal of additions		265,411 ▶	265,411
Other additions:			
Miscellaneous other additions:			
604			
Total	294		
Subtotal of other additions	199	▶	
Total additions	500	265,411 ▶	265,411
Deduct:			
Capital cost allowance from Schedule 8	403	425,045	
Subtotal of deductions		425,045 ▶	425,045
Other deductions:			
Miscellaneous other deductions:			
704			
Total	394		
Subtotal of other deductions	499	0 ▶	0
Total deductions	510	425,045 ▶	425,045
Net income (loss) for income tax purposes – enter on line 300 of the T2 return			42,102

Canada

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DIVIDENDS RECEIVED, TAXABLE DIVIDENDS PAID, AND PART IV TAX CALCULATION

SCHEDULE 3

Name of corporation	Business Number	Tax year-end Year Month Day
Rideau St. Lawrence Distribution Inc.	86485 1993 RC0001	2010-12-31

- 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 in the tax year that qualify for 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 tax 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.*
- "X" under column A if dividend received from a foreign source (connected corporation only).
- Enter in column F1, the amount of dividends received reported in column 240 that are eligible.
- Under column F2, enter the code that applies to the deductible taxable dividend.

Part 1 – Dividends received in the tax year

Do not include dividends received from foreign non-affiliates.

	Name of payer corporation (from which the corporation received the dividend) 200	A	B Enter 1 if payer corporation is connected 205 (Complete if payer corporation is connected)	C Business Number of connected corporation 210 (Complete if payer corporation is connected)	D Tax year-end of the payer corporation in which the sections 112/113 and subsection 138(6) dividends in column F were paid YYYY/MM/DD 220 (Complete if payer corporation is connected)	E Non-taxable dividend under section 83 230
1			2			
					Total (enter on line 402 of Schedule 1)	

Note: If your corporation's tax year-end is different than that of the connected payer corporation, your corporation could have received dividends from more than one tax year of the payer corporation. If so, use a separate line to provide the information for each tax year of the payer corporation.

	F Taxable dividends deductible from taxable income under section 112, subsections 113(2) and 138(6), and paragraphs 113(1)(a), (b), or (d)* 240	F1 Eligible dividends (included in column F)	F2	G Total taxable dividends paid by connected payer corporation (for tax year in column D) 250 (Complete if payer corporation is connected)	H Dividend refund of the connected payer corporation (for tax year in column D)** 260 (Complete if payer corporation is connected)	I Part IV tax before deductions F x 1 / 3 *** 270	
1							
Total (enter the amount from column F on line 320 of the T2 return and amount J in Part 2)							J

* If taxable dividends are received, enter the amount in column 240, but if the corporation is not subject to Part IV tax (such as a public corporation other than a subject corporation as defined in subsection 186(3)), enter "0" in column 270. Life insurers are not subject to Part IV tax on subsection 138(6) dividends.

** If the connected payer corporation's tax year ends after the corporation's balance-due day for the tax year (two or three months, as applicable), you have to estimate the payer's dividend refund when you calculate the corporation's Part IV tax payable.

*** For dividends received from connected corporations: Part IV tax = $\frac{\text{Column F x Column H}}{\text{Column G}}$

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 tax year that qualify for a dividend refund

	A	B	C	D	D1
	Name of connected recipient corporation 400	Business Number 410	Tax year end of connected recipient corporation in which the dividends in column D were received YYYY/MM/DD 420	Taxable dividends paid to connected corporations 430	Eligible dividends (included in column D)
1	RSL Holdings Inc.	89170 9610 RC0001	2010-12-31	130,000	
2					

Note

If your corporation's tax year-end is different than that of the connected recipient corporation, your corporation could have paid dividends in more than one tax year of the recipient corporation. If so, use a separate line to provide the information for each tax year of the recipient corporation.

Total 130,000

Total taxable dividends paid in the tax year to other than connected corporations . . . . 450 ______

Eligible dividends (included in line 450) . . . . 450a ______

Total taxable dividends paid in the tax year that qualify for a dividend refund (total of column D above **plus** line 450) 460 130,000

Part 4 – Total dividends paid in the tax year

Complete this part if the total taxable dividends paid in the tax year that qualify for a dividend refund (line 460 above) is different from the total dividends paid in the tax year.

Total taxable dividends paid in the tax year for the purposes of a dividend refund (from above) 130,000
Other dividends paid in the tax year (total of 510 to 540) . . . . ______
Total dividends paid in the tax year 500 130,000

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 ______ ▶ ______

Total taxable dividends paid in the tax year that qualify for a dividend refund 130,000

SCHEDULE 8

Canada Revenue Agency | Agence du revenu du Canada

CAPITAL COST ALLOWANCE (CCA)

Name of corporation	Business Number	Tax year end Year Month Day
Rideau St. Lawrence Distribution Inc.	86485 1993 RC0001	2010-12-31

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 (See Note) **200**	Description	2 Undepreciated capital cost at the beginning of the year (undepreciated capital cost at the end of last year) **201**	3 Cost of acquisitions during the year (new property must be available for use)* **203**	4 Net adjustments** **205**	5 Proceeds of dispositions during the year (amount not to exceed the capital cost) **207**	6 50% rule (1/2 of the amount, if any, by which the net cost of acquisitions exceeds column 5)*** **211**	7 Reduced undepreciated capital cost	8 CCA rate % **212**	9 Recapture of capital cost allowance (line 107 of Schedule 1) **213**	10 Terminal loss (line 404 of Schedule 1) **215**	11 Capital cost allowance (column 7 **multiplied** by column 8; or a lower amount) (line 403 of Schedule 1)**** **217**	12 Undepreciated capital cost at the end of the year (column 6 **plus** column 7 **minus** column 11) **220**
1.	1	distribution and buildings	3,932,528		452,550	0		4,385,078	4	0	0	175,403	4,209,675
2.	10	computer and vehicles	254,644	37,935		0	18,968	273,611	30	0	0	82,083	210,496
3.	8	Equipment	41,361	3,775		0	1,888	43,248	20	0	0	8,650	36,486
4.	45	Computer Equipment and Softwa	1,580			0		1,580	45	0	0	711	869
5.	46	Data Network Equip.	1,628			0		1,628	30	0	0	488	1,140
6.	47	Distribution and transmission eq	947,336	189,870		0	94,935	1,042,271	8	0	0	83,382	1,053,824
7.	50	Computer Hardware	12,339			0		12,339	55	0	0	6,786	5,553
8.	12	Computer Software	19,197	35,224		0		54,421	100	0	0	54,421	
9.	14	Leasehold Improvements	5,278			0		5,278	NA	0	0	1,759	3,519
10.	52	Computer Hardware	9,056	2,306		0		11,362	100	0	0	11,362	
		Total	5,224,947	269,110	452,550		115,791	5,830,816				425,045	5,521,562

Note: Class numbers followed by a letter indicate the basic rate of the class taking into account the additional deduction allowed.
Class 1a: 4% + 6% = 10% (class 1 to 10%), class 1b: 4% + 2% = 6% (class 1 to 6%).

* 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.

Canada

Fixed Assets Reconciliation

Reconciliation of change in fixed assets per financial statements to amounts used per tax return.

Tax return

Additions for tax purposes – Schedule 8 regular classes		269,110		
Additions for tax purposes – Schedule 8 leasehold improvements	+			
Operating leases capitalized for book purposes	+			
Capital gain deferred	+			
Recapture deferred	+			
Deductible expenses capitalized for book purposes – Schedule 1	+			
Change in Construction work in progress	+			
Total additions per books	=	269,110	▶	269,110
Proceeds up to original cost – Schedule 8 regular classes				
Proceeds up to original cost – Schedule 8 leasehold improvements	+			
Proceeds in excess of original cost – capital gain	+			
Recapture deferred – as above	+			
Capital gain deferred – as above	+			
Pre V-day appreciation	+			
Change in Construction work in progress	+			
Total proceeds per books	=		▶ –	
Depreciation and amortization per accounts – Schedule 1			–	260,560
Loss on disposal of fixed assets per accounts			–	
Gain on disposal of fixed assets per accounts			+	
Net change per tax return			=	8,550

Financial statements

Fixed assets (excluding land) per financial statements		
Closing net book value		4,039,451
Opening net book value	–	4,030,901
Net change per financial statements	=	8,550

If the amounts from the tax return and the financial statements differ, explain why below.

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SCHEDULE 9

RELATED AND ASSOCIATED CORPORATIONS

Name of corporation	Business Number	Tax year end Year Month Day
Rideau St. Lawrence Distribution Inc.	86485 1993 RC0001	2010-12-31

This schedule is to be completed by a corporation having one or more of the following:
- related corporation(s)
- associated corporations(s)

	Name 100	Country of residence (if other than Canada) 200	Business Number (Canadian corporation only) (see note 1) 300	Relationship code (see note 2) 400	Number of common shares owned 500	% of common shares owned 550	Number of preferred shares owned 600	% of preferred shares owned 650	Book value of capital stock 700
1.	Rideau St. Lawrence Holdings		89170 9610 RC0001	1					
2.	Rideau St. Lawrence Utilities		89187 5817 RC0001	3					
3.	Rideau St. Lawrence Services		86485 1795 RC0001	3					

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

SCHEDULE 23

Canada Revenue Agency / Agence du revenu du Canada

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
2006	maximum $300,000
2007	$300,001 to $400,000

Calendar year	Acceptable range
2008	maximum $400,000
2009	$400,001 to $500,000

If the calendar year to which this agreement applies is after 2009, ensure that the total at line A does not exceed $500,000.

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 2010

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 [X]

	1 Names of associated corporations **100**	2 Business Number of associated corporations **200**	3 Association code **300**	4 Business limit for the year (before the allocation) $	5 Percentage of the business limit % **350**	6 Business limit allocated* $ **400**	
1	Rideau St. Lawrence Distribution Inc.	86485 1993 RC0001	1	500,000	85.0000	425,000	
2	Rideau St. Lawrence Holdings	89170 9610 RC0001	1	500,000			
3	Rideau St. Lawrence Utilities	89187 5817 RC0001	1	500,000	15.0000	75,000	
4	Rideau St. Lawrence Services	86485 1795 RC0001	1	500,000			
				Total	100.0000	500,000	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% x (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. If the tax year straddles January 1, 2009, the business limit for the second (or subsequent) tax year(s) will be equal to the lesser of the business limit that would have been determined for the first tax year ending in the calendar year, if $500,000 was used in allocating the amounts among associated corporations and the business limit determined for the second (or subsequent) tax year(s) ending in the same calendar year. Otherwise, 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.

Canada Revenue Agency   Agence du revenu du Canada

SCHEDULE 50

SHAREHOLDER INFORMATION

Name of corporation	Business Number	Tax year end Year Month Day
Rideau St. Lawrence Distribution Inc.	86485 1993 RC0001	2010-12-31

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) 100	Business Number (If a corporation is not registered, enter "NR") 200	Social insurance number 300	Trust number 350	Percentage common shares 400	Percentage preferred shares 500
1	Rideau St. Lawrence Holdings Inc.	89170 9610 RC0001			100.000	
2						
3						
4						
5						
6						
7						
8						
9						
10						

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 516

CAPITAL DEDUCTION ELECTION OF ASSOCIATED GROUP FOR THE ALLOCATION OF NET DEDUCTION

Name of corporation	Business Number	Tax year-end Year Month Day
Rideau St. Lawrence Distribution Inc.	86485 1993 RC0001	2010-12-31

- Complete this schedule to allocate the associated group's net deduction for the capital deduction election under subsection 83(2) of the *Taxation Act, 2007* (Ontario). The associated group includes the filing corporation (see line 190 of Part 2 of Schedule 515, *Ontario Capital Tax on Other than Financial Institutions*).
- If you need more space, attach more schedules.
- File this schedule with the *T2 Corporation Income Tax Return*.

	A Names of eligible corporations in the associated group 100	B Business Number of associated corporations (enter "NR" if a corporation is not registered) 200	C Ontario allocation factor (OAF)* (enter as a percentage) 300	D Total assets** 400	E Net deduction ($15 million x line 300) **multiplied** by line 400 / line 700 500	F Allocation of net deduction *** 600
1.	Rideau St. Lawrence Distribution Inc.	86485 1993 RC0001	100.000	8,209,823	15,000,000	15,000,000
2.	Rideau St. Lawrence Holdings	89170 9610 RC0001				
3.	Rideau St. Lawrence Utilities	89187 5817 RC0001				
4.	Rideau St. Lawrence Services	86485 1795 RC0001				

Total assets of associated group (total of amounts in column D) **700** 8,209,823

Total net deduction (total of amounts in column E) **800** 15,000,000

Total allocated net deduction (total of amounts in column F) (not to exceed amount on line 800) **900** 15,000,000

* OAF from the last tax year ending in the calendar year preceding the calendar year in which the filing corporation's tax year ends.

** Total assets of each corporation in the associated group as recorded in the books and records for the last tax year ending in the calendar year preceding the calendar year in which the filing corporation's tax year ends. If the corporation is not resident in Canada, enter the amount of its total assets situated in Canada.

*** Enter the amount from this column allocated to the filing corporation on line 300 of Schedule 515.

T2 SCH 516

Canada

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 546

CORPORATIONS INFORMATION ACT ANNUAL RETURN FOR ONTARIO CORPORATIONS

Name of corporation	Business Number	Tax year-end Year Month Day
Rideau St. Lawrence Distribution Inc.	86485 1993 RC0001	2010-12-31

- This schedule should be completed by a corporation that is incorporated, continued, or amalgamated in Ontario and subject to the Ontario *Business Corporations Act* (BCA) or Ontario *Corporations Act* (CA), except for registered charities under the federal *Income Tax Act*. This completed schedule serves as a *Corporations Information Act* Annual Return under the *Ontario Corporations Information Act*.
- Complete parts 1 to 4. Complete parts 5 to 7 only to report change(s) in the information recorded on the Ontario Ministry of Government Services (MGS) public record.
- This schedule must set out the required information for the corporation as of the date of delivery of this schedule.
- A completed Ontario *Corporations Information Act* Annual Return must be delivered within six months after the end of the corporation's tax year-end. The MGS considers this return to be delivered on the date that it is filed with the Canada Revenue Agency (CRA) together with the corporation's income tax return.
- It is the corporation's responsibility to ensure that the information shown on the MGS public record is accurate and up-to-date. To review the information shown for the corporation on the public record maintained by the MGS, obtain a Corporation Profile Report. Visit **www.ServiceOntario.ca** for more information.
- This schedule contains non-tax information collected under the authority of the Ontario *Corporations Information Act*. This information will be sent to the MGS for the purposes of recording the information on the public record maintained by the MGS.

Part 1 – Identification

100 Corporation's name (exactly as shown on the MGS public record)
Rideau St. Lawrence Distribution Inc.

Jurisdiction incorporated, continued, or amalgamated, whichever is the most recent	**110** Date of incorporation or amalgamation, whichever is the most recent — Year Month Day	**120** Ontario Corporation No.
Ontario	2000-10-17	1436681

Part 2 – Head or registered office address (P.O. box not acceptable as stand-alone address)

200 Care of (if applicable)

210 Street number	**220** Street name/Rural route/Lot and Concession number	**230** Suite number
985	Industrial Road	

240 Additional address information if applicable (line 220 must be completed first)
PO Box 699

250 Municipality (e.g., city, town)	**260** Province/state	**270** Country	**280** Postal/zip code
Prescott	ON	CA	K0E 1T0

Part 3 – Change identifier

Have there been any changes in any of the information most recently filed for the public record maintained by the MGS for the corporation with respect to names, addresses for service, and the date elected/appointed and, if applicable, the date the election/appointment ceased of the directors and five most senior officers, or with respect to the corporation's mailing address or language of preference? To review the information shown for the corporation on the public record maintained by the MGS, obtain a Corporation Profile Report. For more information, visit **www.ServiceOntario.ca**.

300 1 If there have been no changes, enter **1** in this box and then go to "Part 4 – Certification."
If there are changes, enter **2** in this box and complete the applicable parts on the next page, and then go to "Part 4 – Certification."

Part 4 – Certification

I certify that all information given in this *Corporations Information Act* Annual Return is true, correct, and complete.

450 BECKSTEAD (Last name) **451** ALLAN (First name)

454 ______________________, (Middle name(s))

460 2 Please enter one of the following numbers in this box for the above-named person: **1** for director, **2** for officer, or **3** for other individual having knowledge of the affairs of the corporation. If you are a director and officer, enter **1** or **2**.

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

APPENDIX 4C

Canada Revenue Agency / Agence du revenu du Canada

T2 CORPORATION INCOME TAX RETURN

CLIENT COPY 200

055 Do not use this area

This form serves as a federal, provincial, and territorial corporation income tax return, unless the corporation is located in Quebec or Alberta. If the corporation is located in one of these provinces, you have to file a separate provincial corporation return.

Parts, sections, subsections, paragraphs, and subparagraphs mentioned on this return refer to the federal *Income Tax Act*. This return may contain changes that had not yet become law at the time of printing.

Send one completed copy of this return, including schedules and the *General Index of Financial Information* (GIFI), to your tax centre or tax services office. You have to file the return within six months after the end of the corporation's tax year.

For more information see **www.cra.gc.ca** or Guide T4012, *T2 Corporation – Income Tax Guide*.

Identification

Business Number (BN) 001 86485 1993 RC0001

Corporation's name
002 Rideau St. Lawrence Distribution Inc.

Address of head office
Has this address changed since the last time you filed your T2 return? . . . . 010 1 Yes [ ] 2 No [X]
(If **yes**, complete lines 011 to 018.)
011 P.O. Box 699
012 985 Industrial Road
City: 015 Prescott
Province, territory, or state: 016 ON
Country (other than Canada): 017
Postal code/Zip code: 018 K0E 1T0

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 [X]
(If **yes**, complete lines 021 to 028.)
021 c/o
022
023
City: 025
Province, territory, or state: 026
Country (other than Canada): 027
Postal code/Zip code: 028

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 [X]
(If **yes**, complete lines 031 to 038.)
031 P.O. Box 699
032 985 Industrial Road
City: 035 Prescott
Province, territory, or state: 036 ON
Country (other than Canada): 037
Postal code/Zip code: 038 K0E 1T0

040 **Type of corporation at the end of the tax year**
1 [X] Canadian-controlled private corporation (CCPC)
2 [ ] Other private corporation
3 [ ] Public corporation
4 [ ] Corporation controlled by a public corporation
5 [ ] Other corporation (specify, below)

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 060 2010-01-01 (YYYY MM DD)
Tax year-end 061 2010-12-31 (YYYY MM DD)

Has there been an acquisition of control to which subsection 249(4) applies since the previous tax year? . . . . 063 1 Yes [ ] 2 No [X]
If yes, provide the date control was acquired . . . . 065 ________ YYYY MM DD

Is the date on line 061 a deemed tax year-end in accordance with subsection 249(3.1)? . . . . 066 1 Yes [ ] 2 No [X]

Is the corporation a professional corporation that is a member of a partnership? . . . . 067 1 Yes [ ] 2 No [X]

Is this the first year of filing after:
Incorporation? . . . . 070 1 Yes [ ] 2 No [X]
Amalgamation? . . . . 071 1 Yes [ ] 2 No [X]
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 [X]
If **yes**, complete and attach Schedule 24.

Is this the final tax year before amalgamation? . . . . 076 1 Yes [ ] 2 No [X]

Is this the final return up to dissolution? . . . . 078 1 Yes [ ] 2 No [X]

If an election was made under section 261, state the functional currency used . . . . 079 ________

Is the corporation a resident of Canada?
080 1 Yes [X] 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 [X]
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?	150	X	9
Is the corporation an associated CCPC?	160	X	23
Is the corporation an associated CCPC that is claiming the expenditure limit?	161		49
Does the corporation have any non-resident shareholders?	151		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	162		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?	163		44
Has the corporation paid any royalties, management fees, or other similar payments to residents of Canada?	164		14
Is the corporation claiming a deduction for payments to a type of employee benefit plan?	165		15
Is the corporation claiming a loss or deduction from a tax shelter acquired after August 31, 1989?	166		T5004
Is the corporation a member of a partnership for which a partnership identification number has been assigned?	167		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?	168		22
Did the corporation have any foreign affiliates during the year?	169		25
Has the corporation made any payments to non-residents of Canada under subsections 202(1) and/or 105(1) of the federal *Income Tax Regulations*?	170		29
Has the corporation had any non-arm's length transactions with a non-resident?	171		T106
For private corporations: Does the corporation have any shareholders who own 10% or more of the corporation's common and/or preferred shares?	173	X	50
Has the corporation made payments to, or received amounts from, a retirement compensation plan arrangement during the year?	172		
Is the net income/loss shown on the financial statements different from the net income/loss for income tax purposes?	201	X	1
Has the corporation made any charitable donations; gifts to Canada, a province, or a territory; gifts of cultural or ecological property; or gifts of medicine?	202		2
Has the corporation received any dividends or paid any taxable dividends for purposes of the dividend refund?	203	X	3
Is the corporation claiming any type of losses?	204		4
Is the corporation claiming a provincial or territorial tax credit or does it have a permanent establishment in more than one jurisdiction?	205	X	5
Has the corporation realized any capital gains or incurred any capital losses during the tax year?	206		6
i) Is the corporation (or its associated corporations) 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) does the corporation have aggregate investment income at line 440?	207		7
Does the corporation have any property that is eligible for capital cost allowance?	208	X	8
Does the corporation have any property that is eligible capital property?	210		10
Does the corporation have any resource-related deductions?	212		12
Is the corporation claiming deductible reserves?	213		13
Is the corporation claiming a patronage dividend deduction?	216		16
Is the corporation a credit union claiming a deduction for allocations in proportion to borrowing or an additional deduction?	217		17
Is the corporation an investment corporation or a mutual fund corporation?	218		18
Is the corporation carrying on business in Canada as a non-resident corporation?	220		20
Is the corporation claiming any federal or provincial foreign tax credits, or any federal or provincial logging tax credits?	221		21
Does the corporation have any Canadian manufacturing and processing profits?	227		27
Is the corporation claiming an investment tax credit?	231		31
Is the corporation claiming any scientific research and experimental development (SR&ED) expenditures?	232		T661
Is the total taxable capital employed in Canada of the corporation and its related corporations over $10,000,000?	233		
Is the total taxable capital employed in Canada of the corporation and its associated corporations over $10,000,000?	234		
Is the corporation claiming a surtax credit?	237		37
Is the corporation subject to gross Part VI tax on capital of financial institutions?	238		38
Is the corporation claiming a Part I tax credit?	242		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?	243		43
Is the corporation agreeing to a transfer of the liability for Part VI.1 tax?	244		45
Is the corporation subject to Part II - Tobacco Manufacturers' surtax?	249		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?	250		39
Is the corporation claiming a Canadian film or video production tax credit refund?	253		T1131
Is the corporation claiming a film or video production services tax credit refund?	254		T1177
Is the corporation subject to Part XIII.1 tax? (Show your calculations on a sheet that you identify as Schedule 92.)	255		92

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
Did the corporation pay taxable dividends (other than capital gains dividends) in the tax year?	265	X	55
Has the corporation made an election under subsection 89(11) not to be a CCPC?	266		T2002
Has the corporation revoked any previous election made under subsection 89(11)?	267		T2002
Did the corporation (CCPC or deposit insurance corporation (DIC)) pay eligible dividends, or did its general rate income pool (GRIP) change in the tax year?	268		53
Did the corporation (other than a CCPC or DIC) pay eligible dividends, or did its low rate income pool (LRIP) change in the tax year?	269		54

Additional information

		1 Yes	2 No
Did the corporation use the International Financial Reporting Standards (IFRS) when it prepared its financial statements?	270		X
Is the corporation inactive?	280		X
Has the major business activity changed since the last return was filed? (enter **yes** for first-time filers)	281		X

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.

284	Electricity Distribu	285	100.000 %
286		287	%
288		289	%

		1 Yes	2 No
Did the corporation immigrate to Canada during the tax year?	291		X
Did the corporation emigrate from Canada during the tax year?	292		X
Do you want to be considered as a quarterly instalment remitter if you are eligible?	293	X	

If the corporation was eligible to remit instalments on a quarterly basis for part of the tax year, provide the date the corporation ceased to be eligible 294 ______ YYYY MM DD

If the corporation's major business activity is construction, did you have any subcontractors during the tax year? 295 1 Yes [ ] 2 No [ ]

Taxable income

Net income or (loss) for income tax purposes from Schedule 1, financial statements, or GIFI.	300		44,102	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			
Gifts of medicine from Schedule 2	315			
Taxable dividends deductible under section 112 or 113, or subsection 138(6) from Schedule 3	320			
Part VI.1 tax deduction*	325			
Non-capital losses of previous tax years from Schedule 4	331			
Net capital losses of previous tax years from Schedule 4	332			
Restricted farm losses of previous tax years from Schedule 4	333			
Farm losses of previous tax years from Schedule 4	334			
Limited partnership losses of previous 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				B
Subtotal (amount A **minus** amount B) (if negative, enter "0")			44,102	C
Add: Section 110.5 additions or subparagraph 115(1)(a)(vii) additions	355			D
Taxable income (amount C **plus** amount D)	360		44,102	
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)			44,102	Z

* This amount is equal to 3.2 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	44,102	A
Taxable income from line 360, **minus** 10/3 of the amount on line 632*, **minus** 1/(0.38 - X**) 3.57143 times the amount on line 636***, and **minus** any amount that, because of federal law, is exempt form Part I tax	405	44,102	B

Calculation of the business limit:

For all CCPCs, calculate the amount at line 4 below.

400,000	x	Number of days in the tax year before 2009 / Number of days in the tax year	/ 365	=		1
500,000	x	Number of days in the tax year after 2008 / Number of days in the tax year	365 / 365	=	500,000	2
			Add amounts at lines 1 and 2		500,000	4

Business limit (see notes 1 and 2 below)	410	425,000	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 425,000 x 415 **** ______ D / 11,250 = ______ E

Reduced business limit (amount C **minus** amount E) (if negative, enter "0")	425	425,000	F

Small business deduction

Amount A, B, C, or F, whichever is the least 44,102 x 17 % =	430	7,497	G

Enter amount G on line 1.

* 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.

** General rate reduction percentage for the tax year. It has to be pro-rated.

*** 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 previous tax years, the amount to be entered on 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 previous tax year, the amount to be entered on 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.

General tax reduction for Canadian-controlled private corporations

Canadian-controlled private corporations throughout the tax year

Taxable income from line 360		44,102	A
Lesser of amounts V and Y (line Z1) from Part 9 of Schedule 27	B		
Amount QQ from Part 13 of Schedule 27	C		
Amount used to calculate the credit union deduction from Schedule 17	D		
Amount from line 400, 405, 410, or 425, whichever is the least	44,102 E		
Aggregate investment income from line 440*	F		
Total of amounts B to F	44,102 ▶	44,102	G
Amount A **minus** amount G (if negative, enter "0")			H

Amount H	x	Number of days in the tax year after December 31, 2007, and before January 1, 2009 / Number of days in the tax year	/ 365	x	8.5 %	=	I
Amount H	x	Number of days in the tax year after December 31, 2008, and before January 1, 2010 / Number of days in the tax year	/ 365	x	9 %	=	J
Amount H	x	Number of days in the tax year after December 31, 2009, and before January 1, 2011 / Number of days in the tax year	365 / 365	x	10 %	=	K
Amount H	x	Number of days in the tax year after December 31, 2010, and before January 1, 2012 / Number of days in the tax year	/ 365	x	11.5 %	=	L
Amount H	x	Number of days in the tax year after 2011 / Number of days in the tax year	/ 365	x	13 %	=	L.1

General tax reduction for Canadian-controlled private corporations – Total of amounts I to L.1 .... M
Enter amount M on line 638.

* Except for a corporation that is, throughout the year, a cooperative corporation (within the meaning assigned by subsection 136(2)) or a credit union.

General tax reduction

Do not complete this area if you are a Canadian-controlled private corporation, an investment corporation, a mortgage investment corporation, a mutual fund corporation, or any corporation with taxable income that is not subject to the corporation tax rate of 38%.

Taxable income from page 3 (line 360 or amount Z, whichever applies)			N
Lesser of amounts V and Y (line Z1) from Part 9 of Schedule 27	O		
Amount QQ from Part 13 of Schedule 27	P		
Amount used to calculate the credit union deduction from Schedule 17	Q		
Total of amounts O to Q	▶		R
Amount N **minus** amount R (if negative, enter "0")			S

Amount S	x	Number of days in the tax year after December 31, 2007, and before January 1, 2009 / Number of days in the tax year	/ 365	x	8.5 %	=	T
Amount S	x	Number of days in the tax year after December 31, 2008, and before January 1, 2010 / Number of days in the tax year	/ 365	x	9 %	=	U
Amount S	x	Number of days in the tax year after December 31, 2009, and before January 1, 2011 / Number of days in the tax year	365 / 365	x	10 %	=	V
Amount S	x	Number of days in the tax year after December 31, 2010, and before January 2012 / Number of days in the tax year	/ 365	x	11.5 %	=	W
Amount S	x	Number of days in the tax year after 2011 / Number of days in the tax year	/ 365	x	13 %	=	W.1

General tax reduction – Total of amounts T to W.1 X
Enter amount X on line 639.

Refundable portion of Part I tax

Canadian-controlled private corporations throughout the tax year

Aggregate investment income from Schedule 7	**440**		x 26 2 / 3 % =		A
Foreign non-business income tax credit from line 632					
Deduct: Foreign investment income from Schedule 7	**445**		x 9 1 / 3 % =		
			(if negative, enter "0")		B
Amount A **minus** amount B (if negative, enter "0")					C
Taxable income from line 360			44,102		
Deduct:					
Amount from line 400, 405, 410, or 425, whichever is the least		44,102			
Foreign non-business income tax credit from line 632	x 25 / 9 =				
Foreign business income tax credit from line 636	x 1(0.38 - X*) / 3.57143 =				
		44,102	44,102		
			x 26 2 / 3 % =		D
Part I tax payable minus investment tax credit refund (line 700 **minus** line 780)				4,852	E
Refundable portion of Part I tax – Amount C, D, or E, whichever is the least	**450**				F

* General rate reduction percentage for the tax year. It has to be pro-rated.

Refundable dividend tax on hand

Refundable dividend tax on hand at the end of the previous tax year	**460**			
Deduct: Dividend refund for the previous tax year	**465**			
				G
Add the total of:				
Refundable portion of Part I tax from line 450 above				
Total Part IV tax payable from 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	130,000	x 1 / 3	43,333	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 – Taxable income (line 360 or amount Z, whichever applies) multiplied by 38 %			550	16,759 A
Recapture of investment tax credit from Schedule 31			602	B

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	44,102		
Deduct:			
Amount from line 400, 405, 410, or 425, whichever is the least	44,102		
Net amount		▶	ii

Refundable tax on CCPC's investment income – 6 2 / 3 % of whichever is less: amount i or ii	604	C
Subtotal (add lines A to C)		16,759 D

Deduct:

Small business deduction from line 430		7,497 1	
Federal tax abatement	608	4,410	
Manufacturing and processing profits deduction from Schedule 27	616		
Investment corporation deduction	620		
Taxed capital gains 624			
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		
General tax reduction for CCPCs from amount M	638		
General tax reduction from amount X	639		
Federal logging tax credit from Schedule 21	640		
Federal qualifying environmental trust tax credit	648		
Investment tax credit from Schedule 31	652		
	Subtotal	11,907 ▶	11,907 E

Part I tax payable – Line D **minus** line E	4,852 F

Enter amount F on line 700.

Summary of tax and credits

Federal tax

Part I tax payable	700	4,852
Part II surtax payable from Schedule 46	708	
Part III.1 tax payable from Schedule 55	710	
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	
Total federal tax		4,852

Add provincial or territorial tax:

Provincial or territorial jurisdiction . . . 750 ON
(if more than one jurisdiction, enter "multiple" and complete Schedule 5)

Net provincial or territorial tax payable (except Quebec and Alberta)	760		
Provincial tax on large corporations (New Brunswick* and Nova Scotia)	765		
Total tax payable	770		4,852 A

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		
Provincial and territorial capital gains refund from Schedule 18	808		
Provincial and territorial refundable tax credits from Schedule 5	812		
Tax instalments paid	840	24,783	
Total credits	890	24,783	24,783 B

Refund code 894 1 Overpayment 19,931

Balance (line A minus line B) -19,931

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

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 ____ Branch number

914 ____ Institution number 918 ____ Account number

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 [X] 2 No [ ]

* The New Brunswick tax on large corporations is eliminated effective January 1, 2009.

Certification

I, 950 BECKSTEAD (Last name in block letters) 951 ALLAN (First name in block letters) 954 CFO (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 2011-06-23 Date (yyyy/mm/dd) ____ Signature of the authorized signing officer of the corporation 956 (613) 925-3851 Telephone number

Is the contact person the same as the authorized signing officer? If **no**, complete the information below . . . 957 1 Yes [X] 2 No [ ]

958 ____ Name in block letters 959 ____ Telephone number

Language of correspondence – Langue de correspondance

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. 990 [1]

Schedule of Instalment Remittances

Name of corporation contact

Telephone number

Effective interest date	Description (instalment remittance, split payment, assessed credit)	Amount of credit
	Installments paid during the year	24,783

Total amount of instalments claimed (carry the result to line 840 of the T2 Return) 24,783 A

Total instalments credited to the taxation year per T9 24,783 B

Transfer

	Account number	Taxation year end	Amount	Effective interest date	Description
From:					
To:					
From:					
To:					
From:					
To:					
From:					
To:					
From:					
To:					

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 100

Form identifier 100

GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Name of corporation	Business Number	Tax year end Year Month Day
Rideau St. Lawrence Distribution Inc.	86485 1993 RC0001	2010-12-31

Balance sheet information

Account	Description	GIFI		Current year	Prior year
	Assets				
	Total current assets	1599	+	3,253,139	2,928,818
	Total tangible capital assets	2008	+	6,028,198	5,759,090
	Total accumulated amortization of tangible capital assets	2009	–	1,904,542	1,643,984
	Total intangible capital assets	2178	+		
	Total accumulated amortization of intangible capital assets	2179	–		
	Total long-term assets	2589	+	478,190	1,165,899
	* Assets held in trust	2590	+		
	Total assets (mandatory field)	2599	=	7,854,985	8,209,823
	Liabilities				
	Total current liabilities	3139	+	1,860,182	3,101,635
	Total long-term liabilities	3450	+	2,443,359	1,628,480
	* Subordinated debt	3460	+		
	* Amounts held in trust	3470	+		
	Total liabilities (mandatory field)	3499	=	4,303,541	4,730,115
	Shareholder equity				
	Total shareholder equity (mandatory field)	3620	+	3,551,444	3,479,708
	Total liabilities and shareholder equity	3640	=	7,854,985	8,209,823
	Retained earnings				
	Retained earnings/deficit – end (mandatory field)	3849	=	1,040,321	968,585

* Generic item

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SCHEDULE 125

Form identifier 125

GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Name of corporation	Business Number	Tax year end Year Month Day
Rideau St. Lawrence Distribution Inc.	86485 1993 RC0001	2010-12-31

Income statement information

Description GIFI

Operating name 0001
Description of the operation 0002
Sequence Number 0003 01

Account	Description	GIFI		Current year	Prior year
	Income statement information				
	Total sales of goods and services	8089	+	11,108,483	10,962,543
	Cost of sales	8518	–	9,131,849	8,978,754
	Gross profit/loss	8519	=	1,976,634	1,983,789
	Cost of sales	8518	+	9,131,849	8,978,754
	Total operating expenses	9367	+	2,019,057	1,998,432
	Total expenses (mandatory field)	9368	=	11,150,906	10,977,186
	Total revenue (mandatory field)	8299	+	11,357,493	11,243,530
	Total expenses (mandatory field)	9368	–	11,150,906	10,977,186
	Net non-farming income	9369	=	206,587	266,344
	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	=	206,587	266,344
	Total other comprehensive income	9998	=		
	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	–	4,851	28,706
	Deferred income tax provision	9995	–		
	Total – Other comprehensive income	9998	+		
	Net income/loss after taxes and extraordinary items (mandatory field)	9999	=	201,736	237,638

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SCHEDULE 141

NOTES CHECKLIST

Corporation's name	Business Number	Tax year-end Year Month Day
Rideau St. Lawrence Distribution Inc.	86485 1993 RC0001	2010-12-31

- Parts 1, 2, and 3 of this schedule must be completed from the perspective of the person (referred to in these parts as the "accountant") who prepared or reported on the financial statements.
- For more information, see Guide RC4088, *General Index of Financial Information (GIFI) for Corporations* and Guide T4012, *T2 Corporation – Income Tax Guide.*
- Complete this schedule, and include it with your T2 return along with the other GIFI schedules.

If the person preparing the tax return is not the accountant referred to above, they must still complete Parts 1, 2, 3, and 4, as applicable.

Part 1 – Information on the accountant preparing or reporting on the financial statements

Does the accountant have a professional designation? . . . . . **095** 1 Yes [X] 2 No [ ]

Is the accountant connected* with the corporation? . . . . . **097** 1 Yes [ ] 2 No [X]

* 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 accountant does not have a professional designation or is connected to the corporation, you do not have to complete Parts 2 and 3 of this schedule. However, you do have to complete Part 4, as applicable.

Part 2 – Type of involvement with the financial statements

Choose the option that represents the highest level of involvement of the accountant: **198**

Completed an auditor's report . . . . . 1 [X]

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 with the financial statements** above, answer the following question:

Has the accountant expressed a reservation? . . . . . **099** 1 Yes [ ] 2 No [X]

Part 4 – Other information

If you have a professional designation and are not the accountant associated with the financial statements in Part 1 above, choose one of the following options: **110**

Prepared the tax return (financial statements prepared by client) . . . . . 1 [ ]

Prepared the tax return and the financial information contained therein (financial statements have not been prepared) . . . . . 2 [ ]

Were notes to the financial statements prepared? . . . . . **101** 1 Yes [X] 2 No [ ]

If **yes**, complete lines 102 to 107 below:

Are any values presented at other than cost? . . . . . **102** 1 Yes [ ] 2 No [X]

Has there been a change in accounting policies since the last return? . . . . . **103** 1 Yes [ ] 2 No [X]

Are subsequent events mentioned in the notes? . . . . . **104** 1 Yes [ ] 2 No [X]

Is re-evaluation of asset information mentioned in the notes? . . . . . **105** 1 Yes [ ] 2 No [X]

Is contingent liability information mentioned in the notes? . . . . . **106** 1 Yes [ ] 2 No [X]

Is information regarding commitments mentioned in the notes? . . . . . **107** 1 Yes [X] 2 No [ ]

Does the corporation have investments in joint venture(s) or partnership(s)? . . . . . **108** 1 Yes [ ] 2 No [X]

If **yes**, complete line 109 below:

Are you filing financial statements of the joint venture(s) or partnership(s)? . . . . . **109** 1 Yes [ ] 2 No [ ]

T2 BAR CODE RETURN

Name: Rideau St. Lawrence Distribution Inc.

BN: 86485 1993 RC 0001

Tax Year Start: 2010-01-01

Tax Year End: 2010-12-31

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

The corporation follows Canadian generally accepted accounting principles for electrical utilities prescribed in the Ontario Energy Board's Accounting Procedures Handbook under the authority of Acts of the Province of Ontario and permitted by the Ontario Energy Board.

(a) Revenue recognition

Revenue from the sale of electricity is recorded when billed. Unbilled revenue is the accrual for electricity sold between the last billing date and the year end date. The unbilled revenue adjustment is the change between the opening and closing balances of unbilled revenue and is included in revenue. Other income is recorded when services have been provided.

(b) Investments

Investments are recorded at lower of cost and market.

(c) Inventory

Inventory is valued at the lower of cost and net realizable value. Inventory is recorded using the average cost method.

(d) Capital assets and amortization

Capital assets are stated at acquisition cost and amortized using the straight line method over five to forty years.

(e) Construction in progress

Capital items purchased for capital projects under construction are included in construction in progress and are not amortized until put into service.

(f) Contributions and grants in aid of construction

Contributions and grants received in aid of construction are recorded as a deduction against capital assets. The amount is amortized on the same basis as the asset constructed and credited to amortization expense. No amortization is recorded until the asset is in use.

(g) Customer deposits

Deposits taken to guarantee the payment of power bills or contract performance are shown as a current or long term liability depending on the terms of repayment.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

(h) Use of estimates

The preparation of financial statements in conformity with Canadian generally accepted accounting principles 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 revenues and expenditures during the period. Actual results could differ from these estimates.

(i) Net regulatory assets and liabilities

The Ontario Energy Board provided accounting guidelines to include or exclude costs, revenues, losses or gains in the rates of a specific period, resulting in accounting recognition that differs from an unregulated company under Canadian generally accepted accounting principles. Such differences involves the application of rate regulated accounting resulting in the recognition of regulatory assets and liabilities. Regulatory assets represent certain amounts receivable from future customers and costs that have been deferred for accounting purposes that are expected be recovered in future rates. Any regulatory liabilities represents funds received in different periods that have been deferred for accounting purposes that are expected to be adjusted in future rates or recognize as revenue in future periods. The corporation continually assess the likelihood of recovery of each of its regulatory assets and liabilities into the setting of future rates. If the corporation determines that these regulatory assets and liabilities will no longer form as part of future rates, the appropriate carrying amount would be included in the results of operations in the period that the assessment is made. Description of regulatory assets is as follows:

(i) Retail settlement variance accounts

Retail settlement variance accounts are the net of sales and expenses incurred by the corporation for retail settlement after the commencement of market opening on May 1, 2002. The net sales and expenses are to be recovered through future rate increases, under Article 490 of the Ontario Energy Board Accounting Procedures Handbook. A return of capital is capitalized on these amounts based on Article 490.

(ii) Smart meter capital cost variance account

Smart meter capital cost variance account is the net of smart meter capital expenses and related incremental operating, maintenance, amortization and administration expenses incurred by the corporation less accumulated billings to offset those costs. The net expenses are to be recovered through future rate increases under Article 490 of the Ontario Energy Board Accounting Procedures Handbook. A return of capital is capitalized on these amounts based on Article 490.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

(j) Corporate income and capital taxes

Under the Electricity Act, 1998, the corporation is required to make payments in lieu of corporate taxes to the Ontario Energy Finance corporation. These payments are calculated in accordance with the rules of computing income and taxable capital and other relevant amounts contained in the Income Tax Act (Canada) and the Corporation Tax Act (Ontario) as modified by the Electricity Act, 1998, and related regulations.

The corporation provides for payments in lieu of corporate income taxes relating to its regulated businesses using the taxes payable method as directed by the Ontario Energy Board. 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. When recorded future income taxes become payable, it is expected that they will be included in the rates approved by the Ontario Energy Board and recovered from the customers of the corporation at that time.

(k) Financial instruments

(i) Fair value of financial instruments

CICA Handbook Section 3855 establishes standards for recognizing and measuring financial assets, financial liabilities and derivatives. This standard prescribes when to recognize a financial instrument in the balance sheet and at what amount. Depending on the classification, fair value or cost based measures are used. The standard also prescribes the basis of presentation for gains and losses on financial instruments. Based on financial instrument classification, gains and losses on financial instruments are recognized in net income or as other comprehensive income.

The corporation has made the following classifications:

(i) Cash and investments are classified as "held for trading." They are measured at fair value and any gains or losses resulting from the re measurement at end of each period are recognized in net income.

(ii) Accounts receivable and unbilled revenue are classified as "loans and receivables." They are recorded at cost, which upon their initial measurement is equal to their fair value. Subsequent measurements are recorded at amortized cost using the effective interest method.

(iii) Accounts payables and customer deposits are classified as "financial liabilities." They are recorded at their cost which upon their initial measurement is equal to their fair value. Subsequent measurements are recorded at amortized cost using the effective interest method.

The carrying amounts reported on the balance sheet for cash, investments, accounts receivable, unbilled revenue, accounts payable and customer deposits, approximate fair values due to the immediate and short term maturities of these financial instruments.

The fair value of long term debt, including the current portion, is based on rates currently available to the corporation with similar terms and maturities and approximates its carrying amounts as disclosed on the balance sheet.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

(k) Financial instruments (continued)

(ii) Concentration of credit risk

The corporation does not believe it is subject to any significant concentration of credit risk. Cash is in place with major financial institutions. Accounts receivable are the result of sales to individuals, corporations and not for profit organizations geographically concentrated within Eastern Ontario.

(iii) Comprehensive income Section 1530

This Section describes the recognition and disclosure requirements with respect to comprehensive income. Comprehensive income consists of net income and other comprehensive income. Other comprehensive income represents the changes in the fair value of financial instruments which have not been included in net income. As the corporation did not have any adjustments to other comprehensive income during the year, this standard does not have an impact on the financial statements.

(l) International Financial Reporting Standards ("IFRS")

The Canadian Institute of Chartered Accountants announced that Canadian publicly accountable enterprises will be required to adopt International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("ISAB"), effective January 1, 2011. On September 10, 2010, the Canadian Accounting Standards Board ("AcSB") decided to permit rate regulated entities to defer their IFRS implementation date to January 1, 2012. As such, the corporation will apply IFRS to its financial statements commencing January 1, 2012 with restatement of the amounts recorded on the opening IFRS balance sheet as at January 1, 2011 for comparative purposes. While the corporation is currently developing an implementation plan for the adoption of IFRS, the financial reporting impact of the transition to IFRS cannot be reasonably estimated at this time.

2. INVESTMENTS

The corporation exchanged its ownership of 18,000 units with a zero carrying value of Enerconnect Limited Partnership for 12,067 shares of Utilismart Corporation in December 2007. The shares of Utilismart Corporation are to be distributed to the corporation over a three year period. The corporation received no shares during the year for an accounting gain of $ (2009 $2,414).

3. CAPITAL

	Cost	Accumulated Amortization	Net 2010	Net 2009
Land	$ 84,205	$ -	$ 84,205	$ 84,205
Buildings, leasehold improvements and fixtures	91,084	8,847	82,237	84,762
Distribution equipment	5,772,398	1,702,991	4,069,407	4,097,113
Tools and equipment	132,984	97,597	35,387	44,721
Computer hardware and software	308,514	175,098	133,416	99,741
Less: Contributions in aid of construction	(360,987)	(79,991)	(280,996)	(295,436)
	$ 6,028,198	$ 1,904,542	$ 4,123,656	$ 4,115,106

4. NET REGULATORY ASSETS

	2010	2009
Retail settlement variance accounts	$ (468,978)	$ 346,371

Smart meter capital cost variance account 1,159,503

819,528

Smart meter funding (212,335) -

$ 478,190 $ 1,165,899

The Ontario Energy Board approved billing rates for the recovery of smart meter capital costs on a non prudential basis of $2.00 per customer per month in 2010. The corporation will be applying for full cost recovery of the smart meter capital costs in future rate applications through the Ontario Energy Board.

5. TEMPORARY ADVANCES

	2010	2009
Demand loan	$ -	$ 833,403
Demand loan	-	245,000
	$ -	$ 1,078,403

Demand loans are non revolving loans that bear interest at prime, interest only payments for first twelve months, maximum borrowing limit of $1,695,000 and are secured by a general security agreement dated May 20, 2009.
The corporation has an overdraft lending facility up to $750,000 that was not utilized as of December 31, 2010 with the same terms and conditions as the demand loans indicated in Note 6. The consolidated corporation provided a guarantee for the indebtedness up to $2,445,000 dated July 8, 2009.

6. CALLABLE DEBT

2010 2009

Demand loan, interest at prime, monthly payments of $6,945 plus interest,

$ 791,733 $ -

due on demand, secured by equipment and general security agreement

Demand loan, interest at prime, monthly payments of $2,553 plus interest,

214,375 -

due on demand, secured by vehicle and general security agreement

1,006,108 -

Less: current portion 113,965 -

$ 892,143 $ -

The repayment of callable debt is as follows:

2011	$ 113,965
2012	113,965
2013	113,965
2014	113,965
2015	113,965
Thereafter	436,283
	$ 1,006,108

The demand loans are classified as callable debt obligations where the lender has or retains the right to demand full payment of the obligation over the course of the loans. These amounts would not be repaid within one year unless the lender exercises their right to demand payment in full.

7. REGULATORY LIABILITIES

Regulatory liabilities represents funds received for the transfer of Hydro One low voltage regulatory assets and the Conservation and Demand Management (C&DM) program. Costs are recorded against these funds when incurred.

Transactions are summarized as follows:

Hydro One

Low Voltage C&DM

Transfer Program 2010 2009

Balance, beginning of year $ - $ - $ -

$ 19,314

Transfer of regulatory liabilities - - -

38,718

Disbursements against regulatory liabilities - -

- (43,524)

Balance, end of year $ - $ - $ - $

14,508

8. ADVANCES FROM RELATED PARTIES

2010 2009

Advances from Rideau St. Lawrence Utilities Inc. $ 248,383 $

302,030

Advances from Rideau St. Lawrence Services Inc. 13,702

9,482

$ 262,085 $ 311,512

The corporation is related to Rideau St. Lawrence Holdings Inc., Rideau St. Lawrence Utilities Inc., and Rideau St. Lawrence Services Inc. through common ownership. The corporation is a wholly owned subsidiary of Rideau St. Lawrence Holdings Inc.

During the year, the corporation incurred administration, maintenance and other service expenditures with Rideau St. Lawrence Utilities Inc. Terms and conditions of transactions with Rideau St. Lawrence Utilities Inc. are covered by a Master Services Agreement dated November 1, 2000. Under this agreement, Rideau St. Lawrence Utilities Inc. provides specified services to the corporation on a fee for services basis.

9. LONG TERM DEBT

2010 2009

Loan payable, interest at 4.99%, payable in blended monthly payments $

70,940 $ 188,470

of $10,096, due July 2011, secured by specific assets

Promissory note, Corporation of the Township of Edwardsburgh/Cardinal

225,000 225,000

Promissory note, Corporation of the Township of South Dundas 938,352

938,352

1,234,292 1,351,822

Less: current portion 70,940 117,500

$ 1,163,352 $ 1,234,322

The promissory notes bear interest at a rate determined by the Board of Directors not to exceed 7.25% per annum and are unsecured. Principal and interest shall be payable at the discretion of the Board of Directors.

Interest rate at December 31, 2010 is 4.99%. The repayment of long term debt is as follows:

2011 $ 70,940

Thereafter 1,163,352

$ 1,234,292

10. ADVANCES FROM RELATED PARTY

Advances from related party are from Rideau St. Lawrence Holdings Inc., which bears no interest, has no specific terms of repayment, and are unsecured.

11. CAPITAL STOCK

Authorized

Unlimited common shares

2010 2009

Issued

2,511,123 common shares $ 2,511,123 $ 2,511,123

12. PAYMENTS IN LIEU OF CORPORATE TAXATION

The provision for payments in lieu of corporate income taxes (PIL's) differs from the amount that would have been recorded using the combined Canadian Federal and Ontario statutory income tax rate. A reconciliation between the statutory and effective tax rates is provided as follows:

2010 2009

Income before PIL's $ 206,587 $ 266,344

Federal and Ontario statutory income tax rates 16.00%

16.50%

PIL's at statutory rate 33,054 43,947

Decrease resulting from:

Temporary differences:

Capital cost allowance in excess of amortization (26,319)

(16,501)

Accounting gain on exchange of investments - (398)

Net temporary differences (26,319) (16,899)

Permanent differences:

Corporate Minimum Tax (recovery) (2,204) 6,266

Federal and Ontario Apprenticeship Training Tax Credits, net of tax

320 (4,608)

Net permanent differences (1,884) 1,658

Provision for PIL's $ 4,851 $ 28,706

Effective income tax rate 2.35% 10.78%

As at December 31, 2010, future income tax assets of $237,000 (2009 $198,000), based on current income tax rates, have not been recorded.

13. CONTINGENCIES

The corporation entered into an irrevocable standing letter of credit with a financial institution. The letter of credit is a prudential support obligation required by all small distribution companies in Ontario for the Independent Electricity System Operator (IESO). The prudential support obligation is calculated at $681,809 which the corporation has not exercised as of December 31, 2010.

A class action lawsuit was filed against the corporation and other local electric distribution companies in Ontario by customers who were charged late payment penalties. A settlement was made in July 2010. The corporation's share of the lawsuit settlement is $18,392. This amount has been recorded as accounts payable in these financial statements. The corporation will be recovering these costs over a one year period staring May 1, 2011 as part of its rate base as approved by the Ontario Energy Board.

SCHEDULE 100

GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Form identifier 100

Name of corporation	Business Number	Tax year-end Year Month Day
Rideau St. Lawrence Distribution Inc.	86485 1993 RC0001	2010-12-31

Assets – lines 1000 to 2599

1000	661,035	1060	946,900	1066	19,932
1120	221,106	1180	8,447	1480	1,371,719
1484	24,000	1599	3,253,139	1600	84,205
1680	91,084	1681	-8,847	1740	5,544,395
1741	-1,720,597	1774	308,514	1775	-175,098
2008	6,028,198	2009	-1,904,542	2424	478,190
2589	478,190	2599	7,854,985		

Liabilities – lines 2600 to 3499

2620	1,334,192	2863	262,085	2920	184,905
2961	79,000	3139	1,860,182	3140	2,055,495
3300	343,031	3320	44,833	3450	2,443,359
3499	4,303,541				

Shareholder equity – lines 3500 to 3640

3500	2,511,123	3600	1,040,321	3620	3,551,444
3640	7,854,985				

Retained earnings – lines 3660 to 3849

3660	968,585	3680	201,736	3701	-130,000
3849	1,040,321				

SCHEDULE 125

GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Form identifier 125

Name of corporation	Business Number	Tax year-end Year Month Day
Rideau St. Lawrence Distribution Inc.	86485 1993 RC0001	2010-12-31

Revenue – lines 8000 to 8299

8000	11,108,483	8089	11,108,483	8090	8,573
8140	59,022	8230	181,415	8299	11,357,493

Cost of sales – lines 8300 to 8519

8320	9,131,849	8518	9,131,849	8519	1,976,634

Operating expenses – lines 8520 to 9369

8670	260,560	8710	100,180	8810	710,501
9010	524,711	9270	423,105	9367	2,019,057
9368	11,150,906	9369	206,587		

Farming revenue – lines 9370 to 9659

9659	0

Farming expenses – lines 9660 to 9899

9898	0

Extraordinary items and taxes – lines 9970 to 9999

9970	206,587	9990	4,851	9999	201,736

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NET INCOME (LOSS) FOR INCOME TAX PURPOSES

SCHEDULE 1

Corporation's name	Business Number	Tax year end Year Month Day
Rideau St. Lawrence Distribution Inc.	86485 1993 RC0001	2010-12-31

- 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*.
- Sections, subsections, and paragraphs referred to on this schedule are from the *Income Tax Act*.

Amount calculated on line 9999 from Schedule 125			201,736 A
Add:			
Provision for income taxes – current	101	4,851	
Amortization of tangible assets	104	260,560	
Subtotal of additions		265,411	265,411
Other additions:			
Miscellaneous other additions:			
600 Prior year apprenticship job creation tax credit	290	2,000	
604			
Total	294		
Subtotal of other additions	199	2,000	2,000
Total additions	500	267,411	267,411
Deduct:			
Capital cost allowance from Schedule 8	403	425,045	
Subtotal of deductions		425,045	425,045
Other deductions:			
Miscellaneous other deductions:			
704			
Total	394		
Subtotal of other deductions	499	0	0
Total deductions	510	425,045	425,045
Net income (loss) for income tax purposes – enter on line 300 of the T2 return			44,102

T2 SCH 1 E (10)

Canada

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DIVIDENDS RECEIVED, TAXABLE DIVIDENDS PAID, AND PART IV TAX CALCULATION

SCHEDULE 3

Name of corporation	Business Number	Tax year-end Year Month Day
Rideau St. Lawrence Distribution Inc.	86485 1993 RC0001	2010-12-31

- 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 in the tax year that qualify for 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 tax 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.*
- "X" under column A if dividend received from a foreign source (connected corporation only).
- Enter in column F1, the amount of dividends received reported in column 240 that are eligible.
- Under column F2, enter the code that applies to the deductible taxable dividend.

Part 1 – Dividends received in the tax year

Do not include dividends received from foreign non-affiliates.

	Name of payer corporation (from which the corporation received the dividend) 200	A	B Enter 1 if payer corporation is connected 205 (Complete if payer corporation is connected)	C Business Number of connected corporation 210 (Complete if payer corporation is connected)	D Tax year-end of the payer corporation in which the sections 112/113 and subsection 138(6) dividends in column F were paid YYYY/MM/DD 220 (Complete if payer corporation is connected)	E Non-taxable dividend under section 83 230
1			2			
					Total (enter on line 402 of Schedule 1)	

Note: If your corporation's tax year-end is different than that of the connected payer corporation, your corporation could have received dividends from more than one tax year of the payer corporation. If so, use a separate line to provide the information for each tax year of the payer corporation.

	F Taxable dividends deductible from taxable income under section 112, subsections 113(2) and 138(6), and paragraphs 113(1)(a), (b), or (d)* 240	F1 Eligible dividends (included in column F)	F2	G Total taxable dividends paid by connected payer corporation (for tax year in column D) 250 (Complete if payer corporation is connected)	H Dividend refund of the connected payer corporation (for tax year in column D)** 260 (Complete if payer corporation is connected)	I Part IV tax before deductions F x 1 / 3 *** 270	
1							
							J

Total (enter the amount from column F on line 320 of the T2 return and amount J in Part 2)

* If taxable dividends are received, enter the amount in column 240, but if the corporation is not subject to Part IV tax (such as a public corporation other than a subject corporation as defined in subsection 186(3)), enter "0" in column 270. Life insurers are not subject to Part IV tax on subsection 138(6) dividends.

** If the connected payer corporation's tax year ends after the corporation's balance-due day for the tax year (two or three months, as applicable), you have to estimate the payer's dividend refund when you calculate the corporation's Part IV tax payable.

*** For dividends received from connected corporations: $\text{Part IV tax} = \dfrac{\text{Column F} \times \text{Column H}}{\text{Column G}}$

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 tax year that qualify for a dividend refund

	A	B	C	D	D1
	Name of connected recipient corporation 400	Business Number 410	Tax year end of connected recipient corporation in which the dividends in column D were received YYYY/MM/DD 420	Taxable dividends paid to connected corporations 430	Eligible dividends (included in column D)
1	RSL Holdings Inc.	89170 9610 RC0001	2010-12-31	130,000	
2					

Note
If your corporation's tax year-end is different than that of the connected recipient corporation, your corporation could have paid dividends in more than one tax year of the recipient corporation. If so, use a separate line to provide the information for each tax year of the recipient corporation.

Total 130,000

Total taxable dividends paid in the tax year to other than connected corporations		450	
Eligible dividends (included in line 450)	450a		
Total taxable dividends paid in the tax year that qualify for a dividend refund (total of column D above **plus** line 450)		460	130,000

Part 4 – Total dividends paid in the tax year

Complete this part if the total taxable dividends paid in the tax year that qualify for a dividend refund (line 460 above) is different from the total dividends paid in the tax year.

Total taxable dividends paid in the tax year for the purposes of a dividend refund (from above)			130,000
Other dividends paid in the tax year (total of 510 to 540)			
Total dividends paid in the tax year		500	130,000
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		▶	
Total taxable dividends paid in the tax year that qualify for a dividend refund			130,000

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SCHEDULE 5

TAX CALCULATION SUPPLEMENTARY – CORPORATIONS

Corporation's name	Business Number	Tax year-end Year Month Day
Rideau St. Lawrence Distribution Inc.	86485 1993 RC0001	2010-12-31

- Use this schedule if, during the tax year, the corporation:
  - had a permanent establishment in more than one jurisdiction (corporations that have no taxable income should only complete columns A, B and D in Part 1);
  - is claiming provincial or territorial tax credits or rebates (see Part 2); or
  - has to pay taxes, other than income tax, for Newfoundland and Labrador, or Ontario (see Part 2).
- Regulations mentioned in this schedule are from the *Income Tax Regulations.*
- For more information, see the *T2 Corporation – Income Tax Guide.*
- Enter the regulation number in field 100 of Part 1.

Part 1 – Allocation of taxable income

100 ________________ Enter the regulation that applies (402 to 413).

A Jurisdiction Tick yes if the corporation had a permanent establishment in the jurisdiction during the tax year. *		B Total salaries and wages paid in jurisdiction	C (B x taxable income**) / G	D Gross revenue	E (D x taxable income**) / H	F Allocation of taxable income (C + E) x 1/2 (where either G or H is nil, do not multiply by 1/2)
Newfoundland and Labrador	003 1 Yes ☐	103		143		
Newfoundland and Labrador offshore	004 1 Yes ☐	104		144		
Prince Edward Island	005 1 Yes ☐	105		145		
Nova Scotia	007 1 Yes ☐	107		147		
Nova Scotia offshore	008 1 Yes ☐	108		148		
New Brunswick	009 1 Yes ☐	109		149		
Quebec	011 1 Yes ☐	111		151		
Ontario	013 1 Yes ☐	113		153		
Manitoba	015 1 Yes ☐	115		155		
Saskatchewan	017 1 Yes ☐	117		157		
Alberta	019 1 Yes ☐	119		159		
British Columbia	021 1 Yes ☐	121		161		
Yukon	023 1 Yes ☐	123		163		
Northwest Territories	025 1 Yes ☐	125		165		
Nunavut	026 1 Yes ☐	126		166		
Outside Canada	027 1 Yes ☐	127		167		
Total		129 G		169 H		

* "Permanent establishment" is defined in Regulation 400(2).

** Starting in 2009, if the corporation has income or loss from an international banking centre; the taxable income is the amount on line 360 or line Z of the T2 return **plus** the total amount not required to be included, or **minus** the total amount not allowed to be deducted, in calculating the corporation's income under section 33.1 of the federal *Income Tax Act.*

Notes:

1. After determining the allocation of taxable income, you have to calculate the corporation's provincial or territorial tax payable. For more information on how to calculate the tax for each province or territory, see the instructions for Schedule 5 in the *T2 Corporation – Income Tax Guide.*
2. If the corporation has provincial or territorial tax payable, complete Part 2.

Part 2 – Ontario tax payable, tax credits, and rebates

Total taxable income	Income eligible for small business deduction	Provincial or territorial allocation of taxable income	Provincial or territorial tax payable before credits
44,102	44,102	44,102	2,204

	Line	Amount		Amount	
Ontario basic income tax (from Schedule 500)	270	5,730			
Deduct: Ontario small business deduction (from schedule 500)	402	3,526			
Subtotal (if negative, enter "0")		2,204	►	2,204	A6
Add:					
Surtax re Ontario small business deduction (from Schedule 500)	272				
Ontario additional tax re Crown royalties (from Schedule 504)	274				
Ontario transitional tax debits (from Schedule 506)	276				
Recapture of Ontario research and development tax credit (from Schedule 508)	277				
Subtotal			►		B6
Subtotal (amount A6 **plus** amount B6)				2,204	C6
Deduct:					
Ontario resource tax credit (from Schedule 504)	404				
Ontario tax credit for manufacturing and processing (from Schedule 502)	406				
Ontario foreign tax credit (from Schedule 21)	408				
Ontario credit union tax reduction (from Schedule 500)	410				
Ontario transitional tax credits (from Schedule 506)	414				
Ontario political contributions tax credit (from Schedule 525)	415				
Subtotal			►		D6
Subtotal (amount C6 **minus** amount D6) (if negative, enter "0")				2,204	E6
Deduct: Ontario research and development tax credit (from Schedule 508)			416		
Ontario corporate income tax payable before Ontario corporate minimum tax credit (amount E6 **minus** amount on line 416) (if negative, enter "0")				2,204	F6
Deduct: Ontario corporate minimum tax credit (from schedule 510)			418	2,204	
Ontario corporate income tax payable (amount F6 **minus** amount on line 418) (if negative, enter "0")					G6
Add:					
Ontario corporate minimum tax (from Schedule 510)	278				
Ontario special additional tax on life insurance corporations (from Schedule 512)	280				
Ontario capital tax (from Schedule 514 or Schedule 515, whichever applies)	282				
Subtotal			►		H6
Total Ontario tax payable before refundable credits (amount G6 **plus** amount H6)					I6
Deduct:					
Ontario qualifying environmental trust tax credit	450				
Ontario co-operative education tax credit (from Schedule 550)	452				
Ontario apprenticeship training tax credit (from Schedule 552)	454				
Ontario computer animation and special effects tax credit (from Schedule 554)	456				
Ontario film and television tax credit (from Schedule 556)	458				
Ontario production services tax credit (from Schedule 558)	460				
Ontario interactive digital media tax credit (from Schedule 560)	462				
Ontario sound recording tax credit (from Schedule 562)	464				
Ontario book publishing tax credit (from Schedule 564)	466				
Ontario innovation tax credit (from Schedule 566)	468				
Ontario business-research institute tax credit (from Schedule 568)	470				
Other Ontario tax credits					
Subtotal			►		J6
Net Ontario tax payable or refundable credit (amount I6 **minus** amount J6) (if a credit, enter a negative amount) Include this amount on line 255.			290		K6

Summary

Enter the total net tax payable or refundable credits for all provinces and territories on line 255.

Net provincial and territorial tax payable or refundable credits . . . . 255 ______

If the amount on line 255 is positive, enter the net provincial and territorial tax payable on line 760 of the T2 return.
If the amount on line 255 is negative, enter the net provincial and territorial refundable tax credits on line 812 of the T2 return.

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SCHEDULE 8

CAPITAL COST ALLOWANCE (CCA)

Name of corporation	Business Number	Tax year end Year Month Day
Rideau St. Lawrence Distribution Inc.	86485 1993 RC0001	2010-12-31

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 (See Note)	Description	2 Undepreciated capital cost at the beginning of the year (undepreciated capital cost at the end of last year)	3 Cost of acquisitions during the year (new property must be available for use)*	4 Net adjustments**	5 Proceeds of dispositions during the year (amount not to exceed the capital cost)	6 50% rule (1/2 of the amount, if any, by which the net cost of acquisitions exceeds column 5)***	7 Reduced undepreciated capital cost	8 CCA rate %	9 Recapture of capital cost allowance (line 107 of Schedule 1)	10 Terminal loss (line 404 of Schedule 1)	11 Capital cost allowance (column 7 **multiplied** by column 8; or a lower amount) (line 403 of Schedule 1)****	12 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.	1	distribution and buildings	3,932,528		452,550	0		4,385,078	4	0	0	175,403	4,209,675
2.	10	computer and vehicles	254,644	37,935		0	18,968	273,611	30	0	0	82,083	210,496
3.	8	Equipment	41,361	3,775		0	1,888	43,248	20	0	0	8,650	36,486
4.	45	Computer Equipment and Softwa	1,580			0		1,580	45	0	0	711	869
5.	46	Data Network Equip.	1,628			0		1,628	30	0	0	488	1,140
6.	47	Distribution and transmission eq	947,336	189,870		0	94,935	1,042,271	8	0	0	83,382	1,053,824
7.	50	Computer Hardware	12,339			0		12,339	55	0	0	6,786	5,553
8.	12	Computer Software	19,197	35,224		0		54,421	100	0	0	54,421	
9.	14	Leasehold Improvements	5,278			0		5,278	NA	0	0	1,759	3,519
10.	52	Computer Hardware	9,056	2,306		0		11,362	100	0	0	11,362	
		Total	5,224,947	269,110	452,550		115,791	5,830,816				425,045	5,521,562

Note: Class numbers followed by a letter indicate the basic rate of the class taking into account the additional deduction allowed. Class 1a: 4% + 6% = 10% (class 1 to 10%), class 1b: 4% + 2% = 6% (class 1 to 6%).

* 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.

Fixed Assets Reconciliation

Reconciliation of change in fixed assets per financial statements to amounts used per tax return.

Tax return

Additions for tax purposes – Schedule 8 regular classes		269,110	
Additions for tax purposes – Schedule 8 leasehold improvements	+		
Operating leases capitalized for book purposes	+		
Capital gain deferred	+		
Recapture deferred	+		
Deductible expenses capitalized for book purposes – Schedule 1	+		
Change in Construction work in progress	+		
Total additions per books	=	269,110 ▶	269,110
Proceeds up to original cost – Schedule 8 regular classes			
Proceeds up to original cost – Schedule 8 leasehold improvements	+		
Proceeds in excess of original cost – capital gain	+		
Recapture deferred – as above	+		
Capital gain deferred – as above	+		
Pre V-day appreciation	+		
Change in Construction work in progress	+		
Total proceeds per books	=	▶	–
Depreciation and amortization per accounts – Schedule 1		–	260,560
Loss on disposal of fixed assets per accounts		–	
Gain on disposal of fixed assets per accounts		+	
Net change per tax return		=	8,550

Financial statements

Fixed assets (excluding land) per financial statements

Closing net book value		4,039,451
Opening net book value	–	4,030,901
Net change per financial statements	=	8,550

If the amounts from the tax return and the financial statements differ, explain why below.

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SCHEDULE 9

RELATED AND ASSOCIATED CORPORATIONS

Name of corporation	Business Number	Tax year end Year Month Day
Rideau St. Lawrence Distribution Inc.	86485 1993 RC0001	2010-12-31

This schedule is to be completed by a corporation having one or more of the following:
- related corporation(s)
- associated corporations(s)

	Name 100	Country of residence (if other than Canada) 200	Business Number (Canadian corporation only) (see note 1) 300	Relationship code (see note 2) 400	Number of common shares owned 500	% of common shares owned 550	Number of preferred shares owned 600	% of preferred shares owned 650	Book value of capital stock 700
1.	Rideau St. Lawrence Holdings		89170 9610 RC0001	1					
2.	Rideau St. Lawrence Utilities		89187 5817 RC0001	3					
3.	Rideau St. Lawrence Services		86485 1795 RC0001	3					

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)

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SCHEDULE 23

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
2006	maximum $300,000
2007	$300,001 to $400,000

Calendar year	Acceptable range
2008	maximum $400,000
2009	$400,001 to $500,000

If the calendar year to which this agreement applies is after 2009, ensure that the total at line A does not exceed $500,000.

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 2010

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 [X]

	1 Names of associated corporations 100	2 Business Number of associated corporations 200	3 Association code 300	4 Business limit for the year (before the allocation) $	5 Percentage of the business limit % 350	6 Business limit allocated* $ 400	
1	Rideau St. Lawrence Distribution Inc.	86485 1993 RC0001	1	500,000	85.0000	425,000	
2	Rideau St. Lawrence Holdings	89170 9610 RC0001	1	500,000			
3	Rideau St. Lawrence Utilities	89187 5817 RC0001	1	500,000	15.0000	75,000	
4	Rideau St. Lawrence Services	86485 1795 RC0001	1	500,000			
				Total	100.0000	500,000	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% x (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. If the tax year straddles January 1, 2009, the business limit for the second (or subsequent) tax year(s) will be equal to the lesser of the business limit that would have been determined for the first tax year ending in the calendar year, if $500,000 was used in allocating the amounts among associated corporations and the business limit determined for the second (or subsequent) tax year(s) ending in the same calendar year. Otherwise, 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.

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SCHEDULE 50

SHAREHOLDER INFORMATION

Name of corporation	Business Number	Tax year end Year Month Day
Rideau St. Lawrence Distribution Inc.	86485 1993 RC0001	2010-12-31

All private corporations must complete this schedule for any shareholder who holds 10% or more of the corporation's common and/or preferred shares.

	Name of shareholder (after name, indicate in brackets if the shareholder is a corporation, partnership, individual, or trust)	Provide only one number per shareholder: Business Number (If a corporation is not registered, enter "NR")	Social insurance number	Trust number	Percentage common shares	Percentage preferred shares
	100	200	300	350	400	500
1	Rideau St. Lawrence Holdings Inc.	89170 9610 RC0001			100.000	
2						
3						
4						
5						
6						
7						
8						
9						
10						

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SCHEDULE 55

PART III.1 TAX ON EXCESSIVE ELIGIBLE DIVIDEND DESIGNATIONS

Name of corporation	Business Number	Tax year-end Year Month Day
Rideau St. Lawrence Distribution Inc.	86485 1993 RC0001	2010-12-31

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 of this schedule. 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 (LRIP) Calculation*, 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 federal *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		130,000		
Total taxable dividends paid in the tax year	100	130,000		
Total eligible dividends paid in the tax year			150	
GRIP at the end of the tax year (line 590 on Schedule 53) (if negative, enter "0")			160	
Excessive eligible dividend designation (line 150 **minus** line 160)				A
Part III.1 tax on excessive eligible dividend designations – CCPC or DIC * (amount A **multiplied** by 20 %)			190	

Enter the amount from line 190 on line 710 of the T2 return.

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 (amount from line A of Schedule 54)				B
Part III.1 tax on excessive eligible dividend designations – Other corporations * (amount B **multiplied** by 20 %)			290	

Enter the amount from line 290 on line 710 of the T2 return.

* You can elect to treat all or part of your excessive eligible dividend designation as a separate taxable dividend in order to eliminate or reduce the Part III.1 tax otherwise payable. You must file the election on or before the day that is 90 days **after** the day the notice of assessment for Part III.1 tax was sent. We will accept an election before the assessment of the tax. For more information on how to make this election, go to **www.cra.gc.ca/eligibledividends.**

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SCHEDULE 500

ONTARIO CORPORATION TAX CALCULATION

Name of corporation	Business Number	Tax year-end Year Month Day
Rideau St. Lawrence Distribution Inc.	86485 1993 RC0001	2010-12-31

- Use this schedule if the corporation had a permanent establishment (as defined in section 400 of the federal *Income Tax Regulations*) in Ontario at any time in the tax year and had Ontario taxable income in the year.
- References to subsections and paragraphs are from the federal *Income Tax Act*.
- This schedule is a worksheet only and does not have to be filed with your *T2 Corporation Income Tax Return*.

Part 1 – Calculation of Ontario basic rate of tax for the year

Number of days in the tax year before July 1, 2010 / Number of days in the tax year	181 / 365	x	14.00 %	=	6.94247 %	A1
Number of days in the tax year after June 30, 2010, and before July 1, 2011 / Number of days in the tax year	184 / 365	x	12.00 %	=	6.04932 %	A2
Number of days in the tax year after June 30, 2011, and before July 1, 2012 / Number of days in the tax year	/ 365	x	11.50 %	=	%	A3
Number of days in the tax year after June 30, 2012, and before July 1, 2013 / Number of days in the tax year	/ 365	x	11.00 %	=	%	A4
Number of days in the tax year after June 30, 2013 / Number of days in the tax year	/ 365	x	10.00 %	=	%	A5

Ontario basic rate of tax for the year (total of rates A1 to A5) 12.99179 ► 12.99179 % A6

Part 2 – Calculation of Ontario basic income tax

Ontario taxable income * . . . . 44,102 B

Ontario basic income tax: amount B **multiplied** by Ontario basic rate of tax for the year (rate A6 from Part 1) . . . . . . 5,730 C

If the corporation has a permanent establishment in more than one jurisdiction, or is claiming an Ontario tax credit, in addition to Ontario basic income tax, or has Ontario corporate minimum tax, Ontario special additional tax on life insurance corporations or Ontario capital tax payable, enter amount C on line 270 of Schedule 5, *Tax Calculation Supplementary – Corporations*. Otherwise, enter it on line 760 of the T2 return.

* If the corporation has a permanent establishment only in Ontario, enter the amount from line 360 or line Z, whichever applies, of the T2 return. Otherwise, enter the taxable income allocated to Ontario from column F in Part 1 of Schedule 5.

Part 3 – Ontario small business deduction (OSBD)

Complete this part if the corporation claimed the federal small business deduction under subsection 125(1) or would have claimed it if subsection 125(5.1) had not been applicable in the tax year.

Income from active business carried on in Canada (amount from line 400 of the T2 return)					44,102	1
Federal taxable income, less adjustment for foreign tax credit (amount from line 405 of the T2 return)					44,102	2
Federal business limit before the application of subsection 125(5.1) (amount from line 410 of the T2 return)	425,000	x	500,000 / 500,000 (line 4 on page 4 of the T2 return)	=	425,000	3
Enter the least of amounts 1, 2, and 3					44,102	D
Ontario domestic factor: Ontario taxable income * / taxable income earned in all provinces and territories **			44,102.00 / 44,102	=	1.00000	E
Ontario small business income (amount D **multiplied** by amount E)					44,102	F

Number of days in the tax year before July 1, 2010 / Number of days in the tax year	181 / 365	x	8.50 %	=	4.21507 %	G1
Number of days in the tax year after June 30, 2010, and before July 1, 2011 / Number of days in the tax year	184 / 365	x	7.50 %	=	3.78082 %	G2
Number of days in the tax year after June 30, 2011, and before July 1, 2012 / Number of days in the tax year	/ 365	x	7.00 %	=	%	G3
Number of days in the tax year after June 30, 2012, and before July 1, 2013 / Number of days in the tax year	/ 365	x	6.50 %	=	%	G4
Number of days in the tax year after June 30, 2013 / Number of days in the tax year	/ 365	x	5.50 %	=	%	G5
OSBD rate for the year (total of rates G1 to G5)					7.99589 %	G6

Ontario small business deduction: amount F **multiplied** by OSBD rate for the year (rate G6) . . . 3,526 H

Enter amount H on line 402 of Schedule 5.

* Enter amount B from Part 2.

** Includes the offshore jurisdictions for Nova Scotia and Newfoundland and Labrador.

Part 4 – Calculation of surtax re Ontario small business deduction

Complete this part if the corporation is claiming the OSBD and its adjusted taxable income, **plus** the adjusted taxable income of each corporation with which the corporation was associated during its tax year, is greater than $500,000. If the corporation is a member of an associated group, complete Schedule 501, *Ontario Adjusted Taxable Income of Associated Corporations to Determine Surtax re Ontario Small Business Deduction.*

Note: For days in the tax year after June 30, 2010, the small business surtax rate is 0%. You do not have to complete this part if the corporation's tax year begins after June 30, 2010.

Adjusted taxable income *	44,102 I		
Adjusted taxable income of all associated corporations (amount from line 500 of Schedule 501)	73,635 J		
Aggregate adjusted taxable income (amount I **plus** amount J)	117,737 ▶	117,737	K
Deduct:			
Ontario business limit		500,000	
Subtotal (amount K **minus** Ontario business limit) (if negative, enter "0" on this line and on line P)			L

Small business surtax rate for the year:

$\frac{\text{Number of days in the tax year before July 1, 2010}}{\text{Number of days in the tax year}}$ $\frac{181}{365}$ x 4.25 % = 2.10753 % M

Amount L x % on line M = ... N

Amount N ______ x $\frac{\text{Ontario small business income (amount F from Part 3)}}{500,000}$ $\frac{44,102}{500,000}$ = ... O

Surtax re Ontario small business deduction: lesser of amount O and OSBD (amount H from Part 3) .... P

Enter amount P on line 272 of Schedule 5.

* Adjusted taxable income is equal to the corporation's taxable income or taxable income earned in Canada for the year **plus** the amount of the corporation's adjusted Crown royalties for the year **minus** the amount of the corporation's notional resource allowance for the year (from Schedule 504, *Ontario Resource Tax Credit and Ontario Additional Tax re Crown Royalties*).

If the tax year of the corporation is less than 51 weeks, **multiply** the adjusted taxable income of the corporation for the year by 365 and **divide** by the number of days in the tax year.

Part 5 – Ontario adjusted small business income

Complete this part if the corporation was a Canadian-controlled private corporation throughout the tax year and is claiming the Ontario tax credit for manufacturing and processing or the Ontario credit union tax reduction.

Amount D from Part 3 .... 44,102 Q

$\frac{\text{Surtax payable (amount P from Part 4)}}{\text{Ontario domestic factor (amount E from Part 3) x OSBD rate (rate G6 from Part 3)} \quad 7.99589\ \%}$ $\frac{\quad}{0.07996}$ = ______ R

Note: Enter "0" on line R for tax years beginning after June 30, 2010.

Ontario adjusted small business income (amount Q **minus** amount R) (if negative, enter "0") .... 44,102 S

Enter amount S on line U in Part 6 or on line B in Part 2 of Schedule 502, *Ontario Tax Credit for Manufacturing and Processing*, whichever applies.

Part 6 – Calculation of credit union tax reduction

Complete this part and Schedule 17, *Credit Union Deductions*, if the corporation was a credit union throughout the tax year.

Amount D from Part 3 of Schedule 17			T
Deduct:			
Ontario adjusted small business income (amount S from Part 5)			U
Subtotal (amount T **minus** amount U) (if negative, enter "0")			V
OSBD rate for the year (rate G6 from Part 3)	7.99589 %		
Amount V **multiplied** by the OSBD rate for the year			W
Ontario domestic factor (amount E from Part 3)		1.00000	X
Ontario credit union tax reduction (amount W **multiplied** by amount X)			Y

Enter amount Y on line 410 of Schedule 5.

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SCHEDULE 501

ONTARIO ADJUSTED TAXABLE INCOME OF ASSOCIATED CORPORATIONS TO DETERMINE SURTAX RE ONTARIO SMALL BUSINESS DEDUCTION

Name of corporation	Business Number	Tax year-end Year Month Day
Rideau St. Lawrence Distribution Inc.	86485 1993 RC0001	2010-12-31

- For use by Canadian-controlled private corporations (CCPCs) to report the adjusted taxable income of all corporations (Canadian and foreign) with which the filing corporation was associated at any time during the tax year.
- Include the adjusted taxable income for the tax year of the associated corporation that ends at or before the date of the filing corporation's tax year-end.
- Attach additional schedules if more space is required.
- File this schedule with the *T2 Corporation Income Tax Return.*

	Names of associated corporations* 100	Business number of associated corporations** 200	Tax year-end 300	Adjusted taxable income *** (if loss, enter "0") 400
1	Rideau St. Lawrence Holdings	89170 9610 RC0001	2010-12-31	
2	Rideau St. Lawrence Utilities	89187 5817 RC0001	2010-12-31	73,635
3	Rideau St. Lawrence Services	86485 1795 RC0001	2010-12-31	
			Total 500	73,635

Enter the total adjusted taxable income from line 500 on line J in Part 4 of Schedule 500, *Ontario Corporation Tax Calculation.*

* Subsection 256(2) of the federal *Income Tax Act* may deem the filing corporation to be associated with another corporation, because both corporations are associated with a third corporation. If so, do not list the other corporation, nor the third corporation if it is not a CCPC or has elected under subsection 256(2) of the federal Act not to be associated for purposes of section 125 of the federal Act.

** Enter "NR" if a corporation is not registered.

*** **Rules for adjusted taxable income:**

- If the associated corporation's tax year ends after December 31, 2008, its adjusted taxable income is equal to its taxable income or taxable income earned in Canada **plus** its adjusted Crown royalties **minus** its notional resource allowance for the year.
- If the associated corporation's tax year is less than 51 weeks and is the only tax year of the associated corporation that ends in the filing corporation's tax year, **multiply** the associated corporation's adjusted taxable income by 365 and **divide** by the number of days in the associated corporation's tax year.
- If the associated corporation has two or more tax years ending in the filing corporation's tax year, enter the last tax year-end date on line 300 and, for the entry on line 400, **multiply** the sum of the adjusted taxable income for each of those tax years by 365, and **divide** by the total number of days in all of those tax years.

T2 SCH 501 E (10)

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SCHEDULE 510

ONTARIO CORPORATE MINIMUM TAX

Name of corporation	Business Number	Tax year-end Year Month Day
Rideau St. Lawrence Distribution Inc.	86485 1993 RC0001	2010-12-31

- File this schedule if the corporation is subject to Ontario corporate minimum tax (CMT). CMT is levied under section 55 of the *Taxation Act, 2007* (Ontario), referred to as the "Ontario Act".
- Complete Part 1 to determine if the corporation is subject to CMT for the tax year.
- A corporation not subject to CMT in the tax year is still required to file this schedule if it is deducting a CMT credit, has a CMT credit carryforward, or has a CMT loss carryforward or a current year CMT loss.
- A corporation that has Ontario special additional tax on life insurance corporations (SAT) payable in the tax year must complete Part 4 of this schedule even if it is not subject to CMT for the tax year.
- A corporation is exempt from CMT if, throughout the tax year, it was one of the following:
  1) a corporation exempt from income tax under section 149 of the federal *Income Tax Act*;
  2) a mortgage investment corporation under subsection 130.1(6) of the federal Act;
  3) a deposit insurance corporation under subsection 137.1(5) of the federal Act;
  4) a congregation or business agency to which section 143 of the federal Act applies;
  5) an investment corporation as referred to in subsection 130(3) of the federal Act; or
  6) a mutual fund corporation under subsection 131(8) of the federal Act.
- File this schedule with the *T2 Corporation Income Tax Return*.

Part 1 – Determination of CMT applicability

Total assets of the corporation at the end of the tax year *	112	7,854,985
Share of total assets from partnership(s) and joint venture(s) *	114	
Total assets of associated corporations (amount from line 450 on Schedule 511)	116	4,777,225
Total assets (total of lines 112 to 116)		12,632,210
Total revenue of the corporation for the tax year **	142	11,357,493
Share of total revenue from partnership(s) and joint venture(s) **	144	
Total revenue of associated corporations (amount from line 550 on Schedule 511)	146	915,067
Total revenue (total of lines 142 to 146)		12,272,560

The corporation is subject to CMT if:
- for tax years ending before July 1, 2010, the total assets at the end of the year of the corporation or the associated group of corporations are more than $5,000,000, or the total revenue for the year of the corporation or the associated group of corporations is more than $10,000,000.
- for tax years ending after June 30, 2010, the total assets at the end of the year of the corporation or the associated group of corporations are equal to or more than $50,000,000, and the total revenue for the year of the corporation or the associated group of corporations is equal to or more than $100,000,000.

If the corporation is not subject to CMT, do not complete the remaining parts unless the corporation is deducting a CMT credit, or has a CMT credit carryforward, a CMT loss carryforward, a current year CMT loss, or SAT payable in the year.

* **Rules for total assets**
- Report total assets according to generally accepted accounting principles, adjusted so that consolidation and equity methods are not used.
- Do not include unrealized gains and losses on assets and foreign currency gains and losses on assets that are included in net income for accounting purposes but not in income for corporate income tax purposes.
- The amount on line 114 is determined at the end of the last fiscal period of the partnership or joint venture that ends in the tax year of the corporation. Add the proportionate share of the assets of the partnership(s) and joint venture(s), and deduct the recorded asset(s) for the investment in partnerships and joint ventures.
- A corporation's share in a partnership or joint venture is determined under paragraph 54(5)(b) of the Ontario Act and, if the partnership or joint venture had no income or loss, is calculated as if the partnership's or joint venture's income were $1 million. For a corporation with an indirect interest in a partnership or joint venture, determine the corporation's share according to paragraph 54(5)(c) of the Ontario Act.

** **Rules for total revenue**
- Report total revenue in accordance with generally accepted accounting principles, adjusted so that consolidation and equity methods are not used.
- If the tax year is less than 51 weeks, **multiply** the total revenue of the corporation or the partnership, whichever applies, by 365 and **divide** by the number of days in the tax year.
- The amount on line 144 is determined for the partnership or joint venture fiscal period that ends in the tax year of the corporation. If the partnership or joint venture has 2 or more fiscal periods ending in the filing corporation's tax year, **multiply** the sum of the total revenue for each of the fiscal periods by 365 and **divide** by the total number of days in all the fiscal periods.
- A corporation's share in a partnership or joint venture is determined under paragraph 54(5)(b) of the Ontario Act and, if the partnership or joint venture had no income or loss, is calculated as if the partnership's or joint venture's income were $1 million. For a corporation with an indirect interest in a partnership or joint venture, determine the corporation's share according to paragraph 54(5)(c) of the Ontario Act.

Part 2 – Calculation of adjusted net income/loss for CMT purposes

Net income/loss per financial statements *			210	201,736
Add (to the extent reflected in income/loss):				
Provision for current income taxes/cost of current income taxes	220	4,851		
Provision for deferred income taxes (debits)/cost of future income taxes	222			
Equity losses from corporations	224			
Financial statement loss from partnerships and joint ventures	226			
Dividends deducted on financial statements (subsection 57(2) of the Ontario Act), excluding dividends paid by credit unions under subsection 137(4.1) of the federal Act	230			
Other additions (see note below):				
Share of adjusted net income of partnerships and joint ventures **	228			
Total patronage dividends received, not already included in net income/loss	232			
281	282			
283	284			
Subtotal		4,851 ▶		4,851 A
Deduct (to the extent reflected in income/loss):				
Provision for recovery of current income taxes/benefit of current income taxes	320			
Provision for deferred income taxes (credits)/benefit of future income taxes	322			
Equity income from corporations	324			
Financial statement income from partnerships and joint ventures	326			
Dividends deductible under section 112, section 113, or subsection 138(6) of the federal Act	330			
Dividends not taxable under section 83 of the federal Act (from Schedule 3)	332			
Gain on donation of listed security or ecological gift	340			
Accounting gain on transfer of property to a corporation under section 85 or 85.1 of the federal Act ***	342			
Accounting gain on transfer of property to/from a partnership under section 85 or 97 of the federal Act ****	344			
Accounting gain on disposition of property under subsection 13(4), subsection 14(6), or section 44 of the federal Act *****	346			
Accounting gain on a windup under subsection 88(1) of the federal Act or an amalgamation under section 87 of the federal Act	348			
Other deductions (see note below):				
Share of adjusted net loss of partnerships and joint ventures **	328			
Tax payable on dividends under subsection 191.1(1) of the federal Act **multiplied** by 3	334			
Interest deducted/deductible under paragraph 20(1)(c) or (d) of the federal Act, not already included in net income/loss	336			
Patronage dividends paid (from Schedule 16) not already included in net income/loss	338			
381	382			
383	384			
385	386			
387	388			
389	390			
Subtotal		▶		B
Adjusted net income/loss for CMT purposes (line 210 **plus** amount A **minus** amount B)			490	206,587

If the amount on line 490 is positive and the corporation is subject to CMT as determined in Part 1, enter the amount on line 515 in Part 3.

If the amount on line 490 is negative, enter the amount on line 760 in Part 7 (enter as a positive amount).

Note

In accordance with *Ontario Regulation 37/09*, when calculating net income for CMT purposes, accounting income should be adjusted to:

- exclude unrealized gains and losses due to mark-to-market changes or foreign currency changes on specified mark-to-market property (assets only);
- include realized gains and losses on the disposition of specified mark-to-market property not already included in the accounting income, if the property is not a capital property or is a capital property disposed in the year or in a previous tax year ended after March 22, 2007.

"Specified mark-to-market property" is defined in subsection 54(1) of the Ontario Act.

These rules also apply to partnerships. A corporate partner's share of a partnership's adjusted income flows through on a proportionate basis to the corporate partner.

* **Rules for net income/loss**

- Banks must report net income/loss as per the report accepted by the Superintendent of Financial Institutions under the federal *Bank Act*, adjusted so consolidation and equity methods are not used.

Part 2 – Calculation of adjusted net income/loss for CMT purposes (continued)

- Life insurance corporations must report net income/loss as per the report accepted by the federal Superintendent of Financial Institutions or equivalent provincial insurance regulator, before SAT and adjusted so consolidation and equity methods are not used. If the life insurance corporation is resident in Canada and carries on business in and outside of Canada, **multiply** the net income/loss by the ratio of the Canadian reserve liabilities **divided** by the total reserve liability. The reserve liabilities are calculated in accordance with Regulation 2405(3) of the federal Act.
- Other corporations must report net income/loss in accordance with generally accepted accounting principles, except that consolidation and equity methods must not be used. When the equity method has been used for accounting purposes, equity losses and equity income are removed from book income/loss on lines 224 and 324 respectively.
- Corporations, other than insurance corporations, should report net income from line 9999 of the GIFI (Schedule 125) on line 210.

** The share of the adjusted net income of a partnership or joint venture is calculated as if the partnership or joint venture were a corporation and the tax year of the partnership or joint venture were its fiscal period. For a corporation with an indirect interest in a partnership through one or more partnerships, determine the corporation's share according to clause 54(5)(c) of the Ontario Act.

*** A joint election will be considered made under subsection 60(1) of the Ontario Act if there is an entry on line 342, and an election has been made for transfer of property to a corporation under subsection 85(1) of the federal Act.

**** A joint election will be considered made under subsection 60(2) of the Ontario Act if there is an entry on line 344, and an election has been made under subsection 85(2) or 97(2) of the federal Act.

***** A joint election will be considered made under subsection 61(1) of the Ontario Act if there is an entry on line 346, and an election has been made under subsection 13(4) or 14(6) and/or section 44 of the federal Act.

For more information on how to complete this part, see the *T2 Corporation – Income Tax Guide*.

Part 3 – Calculation of CMT payable

Adjusted net income for CMT purposes (line 490 in Part 2, if positive) . . . . **515** ____________

Deduct:

CMT loss available (amount R from Part 7) . . . . ____________

Minus: Adjustment for an acquisition of control * . . . . . . **518** ____________

Adjusted CMT loss available . . . . ____________ ▶ ____________ C

Net income subject to CMT calculation (if negative, enter "0") . . . . **520** ____________

Amount from line 520 ____________ x $\frac{\text{Number of days in the tax year before July 1, 2010}}{\text{Number of days in the tax year}}$ $\frac{181}{365}$ x 4 % = ____________ 1

Amount from line 520 ____________ x $\frac{\text{Number of days in the tax year after June 30, 2010}}{\text{Number of days in the tax year}}$ $\frac{184}{365}$ x 2.7 % = ____________ 2

Subtotal (amount 1 **plus** amount 2) . . . . ____________ 3

Gross CMT: amount on line 3 above x OAF ** . . . . **540** ____________

Deduct:

Foreign tax credit for CMT purposes *** . . . . **550** ____________

CMT after foreign tax credit deduction (line 540 **minus** line 550) (if negative, enter "0") . . . . ____________ D

Deduct:

Ontario corporate income tax payable before CMT credit (amount F6 from Schedule 5) 2,204

Net CMT payable (if negative, enter "0") . . . . ____________ E

Enter amount E on line 278 of Schedule 5, *Tax Calculation Supplementary – Corporations*, and complete Part 4.

* Enter the portion of CMT loss available that exceeds the adjusted net income for the tax year from carrying on a business before the acquisition of control. See subsection 58(3) of the Ontario Act.

*** Enter "0" on line 550 for life insurance corporations as they are not eligible for this deduction. For all other corporations, enter the cumulative total of amount J for the province of Ontario from Part 9 of Schedule 21 on line 550.

** **Calculation of the Ontario allocation factor (OAF):**

If the provincial or territorial jurisdiction entered on line 750 of the T2 return is "Ontario," enter "1" on line F.

If the provincial or territorial jurisdiction entered on line 750 of the T2 return is "multiple," complete the following calculation, and enter the result on line F:

$\frac{\text{Ontario taxable income ****}}{\text{Taxable income *****}}$ ____________ = ____________

Ontario allocation factor . . . . 1.00000 F

**** Enter the amount allocated to Ontario from column F in Part 1 of Schedule 5. If the taxable income is nil, calculate the amount in column F as if the taxable income were $1,000.

*****Enter the taxable income amount from line 360 or amount Z of the T2 return, whichever applies. If the taxable income is nil, enter "1,000."

Part 4 – Calculation of CMT credit carryforward

CMT credit carryforward at the end of the previous tax year *		15,582		G
Deduct:				
CMT credit expired *	600			
CMT credit carryforward at the beginning of the current tax year * (see note below)		15,582 ▶ 620	15,582	
Add:				
CMT credit carryforward balances transferred on an amalgamation or the windup of a subsidiary (see note below)	650			
CMT credit available for the tax year (amount on line 620 **plus** amount on line 650)			15,582	H
Deduct:				
CMT credit deducted in the current tax year (amount P from Part 5)			2,204	I
Subtotal (amount H **minus** amount I)			13,378	J
Add:				
Net CMT payable (amount E from Part 3)				
SAT payable (amount O from Part 6 of Schedule 512)				
Subtotal		▶		K
CMT credit carryforward at the end of the tax year (amount J **plus** amount K)	670		13,378	L

* For the first harmonized T2 return filed with a tax year that includes days in 2009:
- do not enter an amount on line G or line 600;
- for line 620, enter the amount from line 2336 of Ontario CT23 Schedule 101, *Corporate Minimum Tax (CMT)*, for the last tax year that ended in 2008.

For other tax years, enter on line G the amount from line 670 of Schedule 510 from the previous tax year.

Note: If you entered an amount on line 620 or line 650, complete Part 6.

Part 5 – Calculation of CMT credit deducted from Ontario corporate income tax payable

CMT credit available for the tax year (amount H from Part 4)			15,582	M
Ontario corporate income tax payable before CMT credit (amount F6 from Schedule 5)		2,204 1		
For a corporation that is not a life insurance corporation:				
CMT after foreign tax credit deduction (amount D from Part 3)	2			
For a life insurance corporation:				
Gross CMT (line 540 from Part 3)	3			
Gross SAT (line 460 from Part 6 of Schedule 512)	4			
The **greater** of amounts 3 and 4	5			
Deduct: line 2 or line 5, whichever applies:		6		
Subtotal (if negative, enter "0")		2,204 ▶	2,204	N
Ontario corporate income tax payable before CMT credit (amount F6 from Schedule 5)		2,204		
Deduct:				
Total refundable tax credits excluding Ontario qualifying environmental trust tax credit (amount J6 **minus** line 450 from Schedule 5)				
Subtotal (if negative, enter "0")		2,204 ▶	2,204	O
CMT credit deducted in the current tax year (least of amounts M, N, and O)			2,204	P

Enter amount P on line 418 of Schedule 5 and on line I in Part 4 of this schedule.

Is the corporation claiming a CMT credit earned before an acquisition of control? 675 1 Yes ☐ 2 No ☒

If you answered **yes** to the question at line 675, the CMT credit deducted in the current tax year may be restricted. For information on how the deduction may be restricted, see subsections 53(6) and (7) of the Ontario Act.

Part 6 – Analysis of CMT credit available for carryforward by year of origin

Complete this part if:

- the tax year includes January 1, 2009; or
- the previous tax year-end is deemed to be December 31, 2008, under subsection 249(3) of the federal Act.

Year of origin	CMT credit balance *
10th previous tax year	680
9th previous tax year	681
8th previous tax year	682
7th previous tax year	683
6th previous tax year	684
5th previous tax year	685
4th previous tax year	686
3rd previous tax year	687
2nd previous tax year	688
1st previous tax year	689
Total **	

* CMT credit that was earned (by the corporation, predecessors of the corporation, and subsidiaries wound up into the corporation) in each of the previous 10 tax years and has not been deducted.

** Must equal the total of the amounts entered on lines 620 and 650 in Part 4.

Part 7 – Calculation of CMT loss carryforward

CMT loss carryforward at the end of the previous tax year * . . . . ______ Q

Deduct:

CMT loss expired * . . . . 700 ______

CMT loss carryforward at the beginning of the tax year * (see note below) . . . . ______ ▶ 720 ______

Add:

CMT loss transferred on an amalgamation under section 87 of the federal Act ** (see note below) . . . . 750 ______

CMT loss available (line 720 **plus** line 750) . . . . ______ R

Deduct:

CMT loss deducted against adjusted net income for the tax year (lesser of line 490 (if positive) and line C in Part 3) . . . . ______

Subtotal (if negative, enter "0") ______ S

Add:

Adjusted net loss for CMT purposes (amount from line 490 in Part 2, if **negative**) (enter as a positive amount) . . . . 760 ______

CMT loss carryforward balance at the end of the tax year (amount S **plus** line 760) . . . . 770 ______ T

* For the first harmonized T2 return filed with a tax year that includes days in 2009:

- do not enter an amount on line Q or line 700;
- for line 720, enter the amount from line 2214 of Ontario CT23 Schedule 101, *Corporate Minimum Tax (CMT)*, for the last tax year that ended in 2008.

For other tax years, enter on line Q the amount from line 770 of Schedule 510 from the previous tax year.

** Do not transfer a loss on a vertical amalgamation under subsection 87(2.11) of the federal Act or other amalgamation of a parent and its subsidiary.
Note: If you entered an amount on line 720 or line 750, complete Part 8.

Part 8 – Analysis of CMT loss available for carryforward by year of origin

Complete this part if:

– the tax year includes January 1, 2009; or
– the previous tax year-end is deemed to be December 31, 2008, under subsection 249(3) of the federal Act.

Year of origin	Balance earned in a tax year ending before March 23, 2007 *	Balance earned in a tax year ending after March 22, 2007 **
10th previous tax year	810	820
9th previous tax year	811	821
8th previous tax year	812	822
7th previous tax year	813	823
6th previous tax year	814	824
5th previous tax year	815	825
4th previous tax year	816	826
3rd previous tax year	817	827
2nd previous tax year	818	828
1st previous tax year		829
Total ***		

* Adjusted net loss for CMT purposes that was earned (by the corporation, by subsidiaries wound up into or amalgamated with the corporation before March 22, 2007, and by other predecessors of the corporation) in each of the previous 10 tax years that ended before March 23, 2007, and has not been deducted.

** Adjusted net loss for CMT purposes that was earned (by the corporation and its predecessors, but not by a subsidiary predecessor) in each of the previous 20 tax years that ended after March 22, 2007, and has not been deducted.

*** The total of these two columns must equal the total of the amounts entered on lines 720 and 750.

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SCHEDULE 511

ONTARIO CORPORATE MINIMUM TAX – TOTAL ASSETS AND REVENUE FOR ASSOCIATED CORPORATIONS

Name of corporation	Business Number	Tax year-end Year Month Day
Rideau St. Lawrence Distribution Inc.	86485 1993 RC0001	2010-12-31

- For use by corporations to report the total assets and total revenue of all the Canadian or foreign corporations with which the filing corporation was associated at any time during the tax year. These amounts are required to determine if the filing corporation is subject to corporate minimum tax.
- Total assets and total revenue include the associated corporation's share of any partnership(s)/joint venture(s) total assets and total revenue.
- Attach additional schedules if more space is required.
- File this schedule with the *T2 Corporation Income Tax Return.*

	Names of associated corporations 200	Business number (Canadian corporation only) (see Note 1) 300	Total assets* (see Note 2) 400	Total revenue** (see Note 2) 500
1	Rideau St. Lawrence Holdings	89170 9610 RC0001	3,430,311	0
2	Rideau St. Lawrence Utilities	89187 5817 RC0001	1,305,616	909,067
3	Rideau St. Lawrence Services	86485 1795 RC0001	41,298	6,000
		Total	450 4,777,225	550 915,067

Enter the total assets from line 450 on line 116 in Part 1 of Schedule 510, *Ontario Corporate Minimum Tax*.
Enter the total revenue from line 550 on line 146 in Part 1 of Schedule 510.

Note 1: Enter "NR" if a corporation is not registered.

Note 2: If the associated corporation does not have a tax year that ends in the filing corporation's current tax year but was associated with the filing corporation in the previous tax year of the filing corporation, enter the total revenue and total assets from the tax year of the associated corporation that ends in the previous tax year of the filing corporation.

* **Rules for total assets**

– Report total assets in accordance with generally accepted accounting principles, adjusted so that consolidation and equity methods are not used.
– Include the associated corporation's share of the total assets of partnership(s) and joint venture(s) but exclude the recorded asset(s) for the investment in partnerships and joint ventures.
– Exclude unrealized gains and losses on assets that are included in net income for accounting purposes but not in income for corporate income tax purposes.

** **Rules for total revenue**

– Report total revenue in accordance with generally accepted accounting principles, adjusted so that consolidation and equity methods are not used.
– If the associated corporation has 2 or more tax years ending in the filing corporation's tax year, **multiply** the sum of the total revenue for each of those tax years by 365 and **divide** by the total number of days in all of those tax years.
– If the associated corporation's tax year is less than 51 weeks and is the only tax year of the associated corporation that ends in the filing corporation's tax year, **multiply** the associated corporation's total revenue by 365 and **divide** by the number of days in the associated corporation's tax year.
– Include the associated corporation's share of the total revenue of partnerships and joint ventures.
– If the partnership or joint venture has 2 or more fiscal periods ending in the associated corporation's tax year, **multiply** the sum of the total revenue for each of the fiscal periods by 365 and **divide** by the total number of days in all the fiscal periods.

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SCHEDULE 516

CAPITAL DEDUCTION ELECTION OF ASSOCIATED GROUP FOR THE ALLOCATION OF NET DEDUCTION

Name of corporation	Business Number	Tax year-end Year Month Day
Rideau St. Lawrence Distribution Inc.	86485 1993 RC0001	2010-12-31

- Complete this schedule to allocate the associated group's net deduction for the capital deduction election under subsection 83(2) of the *Taxation Act, 2007* (Ontario). The associated group includes the filing corporation (see line 190 of Part 2 of Schedule 515, *Ontario Capital Tax on Other than Financial Institutions*).
- If you need more space, attach more schedules.
- File this schedule with the *T2 Corporation Income Tax Return*.

	A Names of eligible corporations in the associated group 100	B Business Number of associated corporations (enter "NR" if a corporation is not registered) 200	C Ontario allocation factor (OAF)* (enter as a percentage) 300	D Total assets** 400	E Net deduction ($15 million x line 300) **multiplied by** line 400 / line 700 500	F Allocation of net deduction *** 600
1.	Rideau St. Lawrence Distribution Inc.	86485 1993 RC0001	100.000	8,209,823	15,000,000	15,000,000
2.	Rideau St. Lawrence Holdings	89170 9610 RC0001				
3.	Rideau St. Lawrence Utilities	89187 5817 RC0001				
4.	Rideau St. Lawrence Services	86485 1795 RC0001				

Total assets of associated group (total of amounts in column D) **700** 8,209,823

Total net deduction (total of amounts in column E) **800** 15,000,000

Total allocated net deduction (total of amounts in column F) (not to exceed amount on line 800) **900** 15,000,000

* OAF from the last tax year ending in the calendar year preceding the calendar year in which the filing corporation's tax year ends.

** Total assets of each corporation in the associated group as recorded in the books and records for the last tax year ending in the calendar year preceding the calendar year in which the filing corporation's tax year ends. If the corporation is not resident in Canada, enter the amount of its total assets situated in Canada.

*** Enter the amount from this column allocated to the filing corporation on line 300 of Schedule 515.

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SCHEDULE 546

CORPORATIONS INFORMATION ACT ANNUAL RETURN FOR ONTARIO CORPORATIONS

Name of corporation	Business Number	Tax year-end Year Month Day
Rideau St. Lawrence Distribution Inc.	86485 1993 RC0001	2010-12-31

- This schedule should be completed by a corporation that is incorporated, continued, or amalgamated in Ontario and subject to the Ontario *Business Corporations Act* (BCA) or Ontario *Corporations Act* (CA), except for registered charities under the federal *Income Tax Act*. This completed schedule serves as a *Corporations Information Act* Annual Return under the *Ontario Corporations Information Act*.
- Complete parts 1 to 4. Complete parts 5 to 7 only to report change(s) in the information recorded on the Ontario Ministry of Government Services (MGS) public record.
- This schedule must set out the required information for the corporation as of the date of delivery of this schedule.
- A completed Ontario *Corporations Information Act* Annual Return must be delivered within six months after the end of the corporation's tax year-end. The MGS considers this return to be delivered on the date that it is filed with the Canada Revenue Agency (CRA) together with the corporation's income tax return.
- It is the corporation's responsibility to ensure that the information shown on the MGS public record is accurate and up-to-date. To review the information shown for the corporation on the public record maintained by the MGS, obtain a Corporation Profile Report. Visit **www.ServiceOntario.ca** for more information.
- This schedule contains non-tax information collected under the authority of the Ontario *Corporations Information Act*. This information will be sent to the MGS for the purposes of recording the information on the public record maintained by the MGS.

Part 1 – Identification

100 Corporation's name (exactly as shown on the MGS public record)
Rideau St. Lawrence Distribution Inc.

Jurisdiction incorporated, continued, or amalgamated, whichever is the most recent	**110** Date of incorporation or amalgamation, whichever is the most recent — Year Month Day	**120** Ontario Corporation No.
Ontario	2000-10-17	1436681

Part 2 – Head or registered office address (P.O. box not acceptable as stand-alone address)

200 Care of (if applicable)

210 Street number	**220** Street name/Rural route/Lot and Concession number	**230** Suite number
985	Industrial Road	

240 Additional address information if applicable (line 220 must be completed first)
PO Box 699

250 Municipality (e.g., city, town)	**260** Province/state	**270** Country	**280** Postal/zip code
Prescott	ON	CA	K0E 1T0

Part 3 – Change identifier

Have there been any changes in any of the information most recently filed for the public record maintained by the MGS for the corporation with respect to names, addresses for service, and the date elected/appointed and, if applicable, the date the election/appointment ceased of the directors and five most senior officers, or with respect to the corporation's mailing address or language of preference? To review the information shown for the corporation on the public record maintained by the MGS, obtain a Corporation Profile Report. For more information, visit **www.ServiceOntario.ca**.

300 [1] If there have been no changes, enter **1** in this box and then go to "Part 4 – Certification."
If there are changes, enter **2** in this box and complete the applicable parts on the next page, and then go to "Part 4 – Certification."

Part 4 – Certification

I certify that all information given in this *Corporations Information Act* Annual Return is true, correct, and complete.

450 BECKSTEAD (Last name) **451** ALLAN (First name)

454 ____________ (Middle name(s))

460 [2] Please enter one of the following numbers in this box for the above-named person: **1** for director, **2** for officer, or **3** for other individual having knowledge of the affairs of the corporation. If you are a director and officer, enter **1** or **2**.

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

Complete the applicable parts to report changes in the information recorded on the MGS public record.

Part 5 – Mailing address

500 ☐ Please enter one of the following numbers in this box:

1 - Show no mailing address on the MGS public record.
2 - The corporation's mailing address is the same as the head or registered office address in Part 2 of this schedule.
3 - The corporation's complete mailing address is as follows:

510 Care of (if applicable)		
520 Street number	**530** Street name/Rural route/Lot and Concession number	**540** Suite number
550 Additional address information if applicable (line 530 must be completed first)		

560 Municipality (e.g., city, town)	**570** Province/state	**580** Country	**590** Postal/zip code

Part 6 – Language of preference

600 ☐ Indicate your language of preference by entering **1** for English or **2** for French. This is the language of preference recorded on the MGS public record for communications with the corporation. It may be different from line 990 on the T2 return.

Corporate Taxpayer Summary

Corporate information

Corporation's name: Rideau St. Lawrence Distribution Inc.

Taxation Year: 2010-01-01 to 2010-12-31

Jurisdiction: Ontario

BC	AB	SK	MB	ON	QC	NB	NS	NO	PE	NL	XO	YT	NT	NU	OC
☐	☐	☐	☐	X	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐

Corporation is associated: Y

Corporation is related: Y

Number of associated corporations: 3

Type of corporation: Canadian-Controlled Private Corporation

Total amount due (refund) federal and provincial*: -19,931

* The amounts displayed on lines "Total amount due (refund) federal and provincial" are all listed in the help. Press F1 to consult the context-sensative help.

Summary of federal information

Net income		44,102
Taxable income		44,102
Donations		
Calculation of income from an active business carried on in Canada		44,102
Dividends paid		130,000
Dividends paid – Regular	130,000	
Dividends paid – Eligible		
Balance of the low rate income pool at the end of the previous year		
Balance of the low rate income pool at the end of the year		
Balance of the general rate income pool at the end of the previous year		
Balance of the general rate income pool at the end of the year		
Part I tax (base amount)		16,759

Credits against part I tax		Summary of tax		Refunds/credits	
Small business deduction	7,497	Part I	4,852	ITC refund	
M&P deduction		Part IV		Dividends refund	
Foreign tax credit		Part III.1		Instalments	24,783
Investment tax credits		Other*		Surtax credit	
Abatement/Other*	4,410	Provincial or territorial tax		Other*	
				Balance due/refund (–)	-19,931

* The amounts displayed on lines "Other" are all listed in the Help. Press F1 to consult the context-sensitive help.

Summary of federal carryforward/carryback information

Carryforward balances

Unused surtax credit (Schedule 37): 6,071

Summary of provincial information – provincial income tax payable

	Ontario	Québec (CO-17)	Alberta (AT1)
Net income	44,102		
Taxable income	44,102		
% Allocation	100.00		
Attributed taxable income	44,102		
Surtax		N/A	N/A
Tax payable before deduction*	5,730		
Deductions and credits	5,730		
Net tax payable			
Attributed taxable capital	6,396,960		N/A
Capital tax payable**			N/A
Total tax payable***			
Instalments and refundable credits			
Balance due/Refund (-)			

* For Québec, this includes special taxes and logging operations.

** For Québec, this includes compensation tax and registration fee.

*** For Ontario, this includes the corporate minimum tax, the Crown royalties' additional tax, the transitional tax debit, the recaptured research and development tax credit and the special additional tax debit on life insurance corporations. The Balance due/Refund is included in the federal Balance due/refund.

Summary of provincial carryforward amounts

Other carryforward amounts

Ontario

Corporate minimum tax credit that can be carried forward over 20 years – Schedule 510	6,686
Corporate minimum tax credit that can be carried forward over 10 years – Schedule 510	6,692

Summary – taxable capital

Federal

Corporate name	Taxable capital used to calculate the business limit reduction (T2, line 415)	Taxable capital used to calculate the SR&ED expenditure limit for a CCPC (Schedules 31 and 49)	Taxable capital used to calculate line 233 of the T2 return	Taxable capital used to calculate line 234 of the T2 return
Rideau St. Lawrence Distribution Inc.	6,564,476	6,564,476	6,396,960	6,396,960
Rideau St. Lawrence Holdings				
Rideau St. Lawrence Utilities	421,485	421,485	534,856	534,856
Rideau St. Lawrence Services				
Total	6,985,961	6,985,961	6,931,816	6,931,816

Québec

Corporate name	Paid-up capital used to calculate the deduction relating to income-averaging for forest producers (CO-726.30)	Paid-up capital used to calculate the exemption for small and medium-sized manufacturing businesses (CO-737.18.18)	Paid-up capital used to calculate the Québec business limit reduction (CO-771 and CO-771.1.3)	Paid-up capital used to calculate the tax credit for investment (CO-1029.8.36.IN)	Paid-up capital used to calculate the 1 million deduction (CO-1137.A and CO-1137.E)
Total					

Ontario

Corporate name	Taxable capital used to calculate the capital deduction – Ontario capital tax on financial institutions (Schedule 514)	Taxable capital used to calculate the capital deduction – Ontario capital tax on other than financial institutions (Schedule 515)	Specified capital used to calculate the expenditure limit – Ontario innovation tax credit (Schedule 566)
Rideau St. Lawrence Distribution Inc.		6,396,960	
Rideau St. Lawrence Holdings			
Rideau St. Lawrence Utilities		534,856	
Rideau St. Lawrence Services			
Total		6,931,816	

Other provinces

Corporate name	Capital used to calculate the Newfoundland and Labrador capital deduction on financial institutions (Schedule 306)	Taxable capital used to calculate the Nova Scotia capital deduction on large corporations (Schedule 343)	Net paid up capital – BC capital tax on financial institutions (FIN 689)	BC paid up capital – BC capital tax on financial institutions (FIN 689)
Total				

Five-Year Comparative Summary

	Current year	1st prior year	2nd prior year	3rd prior year	4th prior year
Federal information (T2)					
Taxation year end	**2010-12-31**	**2009-12-31**	**2008-12-31**	**2007-12-31**	**2006-12-31**
Net income	44,102	167,047	165,299	229,841	152,518
Taxable income	44,102	167,047	165,299	229,841	152,518
Active business income	44,102	167,047	165,299	229,841	152,518
Dividends paid	130,000	120,000	106,320	86,000	103,200
Dividends paid – Regular	130,000				
Dividends paid – Eligible					
LRIP – end of the previous year					
LRIP – end of the year					
GRIP – end of the previous year					
GRIP – end of the year					
Donations					
Balance due/refund (-)	-19,931	306	18,183	30,155	-10,148

Federal taxes					
Part I before surtax	4,852	16,375	18,183	87,340	57,957
Surtax				2,574	1,708
Part I.3					
Part IV					
Part I & Surtax	4,852	16,375	18,183	30,155	20,010
Part III.1					
Other*					

* The amounts displayed on lines "Other" are all listed in the help. Press F1 to consult the context-sensative help.

Credits against part I tax					
Small business deduction	7,497	28,398	28,101	36,775	24,403
M&P deduction					
Foreign tax credit					
Political contribution					
Investment tax credit		2,000			
Abatement/other*	4,410	16,705	16,530	22,984	15,252

* The amounts displayed on lines "Other" are all listed in the help. Press F1 to consult the context-sensative help.

Refunds/credits					
ITC refund					
Dividend refund					
Instalments	24,783	28,400			30,158
Surtax credit					
Other*					

* The amounts displayed on lines "Other" are all listed in the help. Press F1 to consult the context-sensative help.

Ontario

Taxation year end	2010-12-31	2009-12-31	2008-12-31	2007-12-31	2006-12-31
Net income	44,102		165,299		
Taxable income	44,102		165,299		
% Allocation	100.00	100.00	100.00		
Attributed taxable income	44,102		165,299	229,841	152,518
Surtax					
Income tax payable before deduction	5,730	23,387	23,142	32,178	21,353
Income tax deductions /credits	5,730	14,199	17,438	19,536	12,964
Net income tax payable		9,188	5,704	9,163	5,899
Taxable capital	6,396,960	6,544,611	4,787,588	5,265,055	5,244,941
Capital tax payable					
Total tax payable*		15,454	6,124	9,163	5,899
Instalments and refundable credits		3,123	30,154	25,935	
Balance due/refund**		12,331	-24,030	-16,772	5,899

* For taxation years ending before January 1, 2009, this includes the corporate minimum tax and the premium tax. For taxation years ending after December 31, 2008, this includes the corporate minimum tax, the Crown royalties' additional tax, the transitional tax debit, the recaptured research and development tax credit and the special additional tax debit on life insurance corporations.

** For taxation years ending after December 31, 2008, the Balance due/Refund is included in the federal Balance due/refund.

Exhibit 5	Cost of Capital and Capital Structure
Schedule	**Contents of Schedule**
1.0	OVERVIEW
	Capital Structure:

1.0 OVERVIEW

The purpose of this evidence is to summarize the method and cost of financing capital requirements for the 2012 test year.

Capital Structure:

The Board – approved 2008 Capital Structure and Cost of Capital (EB-2007-0762) was a deemed capital structure of 49.3% Long-term Debt with a return of 4.99%, 4.0% Short-term Debt with a return of 4.47%, and 46.7% equity with a return of 8.57 %. This provided an overall return of 6.64%.

As directed in the Board decision EB-2007-0762, and “Report to the Board on Cost of Capital and 2nd Generation Incentive Regulation of Ontario’s Electricity Distributors”, RSL managed the transition to a deemed capital structure of 60.0% debt 40.0% equity over two years, starting in 2008. RSL’s current deemed capital structure is 60.0% debt 40.0% equity.

RSL has prepared this rate application with a deemed capital structure of 56% Long Term Debt, 4% Short Term Debt, and 40% Equity to comply with the Report of the Board on Cost of Capital for Ontario Regulated Utilities, issued December 11, 2009 and any subsequent updates.

Deemed Capital Structure for 2008 to 2011 is shown in Table 5.1 below.

Deemed Capital Structure for 2012 is shown in Table 5.2.

TABLE 5.1

Deemed Capital Structure for 2008

Description	$	% of Rate Base	Rate of Return	Return
Long Term Debt	2,571,517	49.30%	4.99%	128,319
Unfunded Short Term Debt	208,642	4.00%	4.47%	9,326
Total Debt	2,780,159	53.30%		137,645
Common Share Equity	2,435,899	46.70%	8.57%	208,757
Total equity	2,435,899	46.70%		208,757
Total Rate Base	5,216,059	100.00%	6.64%	346,402

Deemed Capital Structure for 2009

Description	$	% of Rate Base	Rate of Return	Return
Long Term Debt	2,937,707	52.70%	4.99%	146,592
Unfunded Short Term Debt	222,976	4.00%	4.47%	9,967
Total Debt	3,160,683	56.70%		156,559
Common Share Equity	2,413,714	43.30%	8.57%	206,855
Total equity	2,413,714	43.30%		206,855
Total Rate Base	5,574,397	100.00%	6.52%	363,414

Deemed Capital Structure for 2010

Description	$	% of Rate Base	Rate of Return	Return
Long Term Debt	3,500,456	56.00%	4.99%	174,673
Unfunded Short Term Debt	250,033	4.00%	4.47%	11,176
Total Debt	3,750,488	60.00%		185,849
Common Share Equity	2,500,325	40.00%	8.57%	214,278
Total equity	2,500,325	40.00%		214,278
Total Rate Base	6,250,814	100.00%	6.40%	400,127

Deemed Capital Structure for 2011

Description	$	% of Rate Base	Rate of Return	Return
Long Term Debt	3,918,885	56.00%	4.99%	195,552
Unfunded Short Term Debt	279,920	4.00%	4.47%	12,512
Total Debt	4,198,805	60.00%		208,065
Common Share Equity	2,799,203	40.00%	8.57%	239,892
Total equity	2,799,203	40.00%		239,892
Total Rate Base	6,998,008	100.00%	6.40%	447,957

Table 5.2

Deemed Capital Structure for 2012

Description	$	% of Rate Base	Rate of Return	Return
Long Term Debt	4,044,128	56.00%	4.02%	162,415
Unfunded Short Term Debt	288,866	4.00%	2.08%	6,008
Total Debt	4,332,994	60.00%		168,423
Common Share Equity	2,888,663	40.00%	9.42%	272,112
Total equity	2,888,663	40.00%		272,112
Total Rate Base	7,221,657	100.00%	6.10%	440,535

Return on Equity:

RSL is requesting a return on equity (“ROE”) for the 2012 Test year of 9.42% in accordance with the Cost of Capital Parameter Updates for 2012 Cost of Service Applications issued by the Board on November 12, 2011. RSL understands that the Board will be finalizing the ROE for 2012 rates based on January 2012 market interest rate information. RSL’s use of an ROE of 9.42% is without prejudice to any revised ROE that may be adopted by the OEB in early 2012.

Cost of Debt:

Long Term Debt:

RSL is requesting a return on Long Term Debt for the 2012 Test Year of 4.02%. RSL has a weighted average debt rate of 4.02% on its current Long Term Loans. Details of the loans are provided below on Table 5.6.

Short Term Debt:

RSL is requesting a return on Short Term Debt for the 2012 Test year of 2.08%. RSL understands that the OEB will be finalizing the return on short term debt for 2012 rates based on January 2012 market interest rate information. RSL’s use of a Return on Short Term Debt of 2.08% is without prejudice to any revised ROE that may be adopted by the OEB in early 2012.

Rate Base and Rate of Return:

RSL’s rate base, deemed debt/equity ratios, deemed rate of return, actual debt/equity ratios and actual rates of returns for 2008 Board Approved, 2008 Actual, 2009 Actual, 2011 Bridge Year Forecast, and 2012 Test Year Forecast are shown below in Tables 5.3 to 5.5.

Table 5.6 lists the Debt / Capital Cost Structure for RSL for 2008 Actual, 2009 Actual, 2011 Bridge Year Forecast, and 2012 Test Year Forecast.

Table 5.3 – Capital Structure and Rate Base Calculation for 2008 & 2009.

2008		
Description	**Deemed Portion**	**Effective Rate**
Long-Term Debt	49.30%	4.99%
Short-Tern Debt	4.00%	4.47%
Return On Equity	46.70%	8.57%
Weighted Debt Rate		4.95%
Regulated Rate of Return		6.64%

2009		
Description	**Deemed Portion**	**Effective Rate**
Long-Term Debt	52.70%	4.99%
Short-Tern Debt	4.00%	4.47%
Return On Equity	43.30%	8.57%
Weighted Debt Rate		4.95%
Regulated Rate of Return		6.52%

WORKING CAPITAL ALLOWANCE FOR 2008	
Distribution Expenses	**$**
Distribution Expenses - Operation	189,498
Distribution Expenses - Maintenance	268,548
Billing and Collecting	395,414
Community Relations	486
Administrative and General Expenses	629,125
Taxes Other than Income Taxes	21,292
Less: Capital Taxes within 6105	
Total Eligible Distribution Expenses	**1,504,363**
Power Supply Expenses	8,771,341
Total Working Capital Expenses	10,275,704
Working Capital Allowance rate of 15%	1,541,356

WORKING CAPITAL ALLOWANCE FOR 2009	
Distribution Expenses	
Distribution Expenses - Operation	232,774
Distribution Expenses - Maintenance	292,592
Billing and Collecting	429,851
Community Relations	9,220
Administrative and General Expenses	653,416
Taxes Other than Income Taxes	20,755
Less: Capital Taxes within 6105	0.00
Total Eligible Distribution Expenses	**1,638,607**
Power Supply Expenses	8,978,754
Total Working Capital Expenses	10,617,362
Working Capital Allowance rate of 15%	1,592,604

RATE BASE CALCULATION FOR 2008	
Fixed Assets Opening Balance 2008	3,500,926
Fixed Assets Closing Balance 2008	3,848,480
Average Fixed Asset Balance for 2008	3,674,703
Working Capital Allowance	1,541,356
Rate Base	5,216,059
Regulated Rate of Return	6.64%
Regulated Return on Capital	346,402
Deemed Interest Expense	137,645
Deemed Return on Equity	208,757

RATE BASE CALCULATION FOR 2009	
Fixed Assets Opening Balance 2009	3,848,480
Fixed Assets Closing Balance 2009	4,115,106
Average Fixed Asset Balance for 2009	3,981,793
Working Capital Allowance	1,592,604
Rate Base	5,574,397
Regulated Rate of Return	6.52%
Regulated Return on Capital	363,414
Deemed Interest Expense	156,559
Deemed Return on Equity	206,855

Table 5.4 – Capital Structure and Rate Base Calculation for 2010 and 2011

2010			2011		
Description	**Deemed Portion**	**Effective Rate**	**Description**	**Deemed Portion**	**Effective Rate**
Long-Term Debt	56.00%	4.99%	Long-Term Debt	56.00%	4.99%
Short-Tern Debt	4.00%	4.47%	Short-Tern Debt	4.00%	4.47%
Return On Equity	40.00%	8.57%	Return On Equity	40.00%	8.57%
Weighted Debt Rate		4.96%	**Weighted Debt Rate**		4.96%
Regulated Rate of Return		6.40%	**Regulated Rate of Return**		6.40%

WORKING CAPITAL ALLOWANCE FOR 2010		WORKING CAPITAL ALLOWANCE FOR 2011	
Distribution Expenses		**Distribution Expenses**	
Distribution Expenses - Operation	178,302	Distribution Expenses - Operation	310,045
Distribution Expenses - Maintenance	346,408	Distribution Expenses - Maintenance	401,700
Billing and Collecting	422,655	Billing and Collecting	422,000
Community Relations	450	Community Relations	3,500
Administrative and General Expenses	695,208	Administrative and General Expenses	669,264
Taxes Other than Income Taxes	21,558	Taxes Other than Income Taxes	22,400
Less: Capital Taxes within 6105	-	Less: Capital Taxes within 6105	
Total Eligible Distribution Expenses	**1,664,583**	**Total Eligible Distribution Expenses**	**1,828,909**
Power Supply Expenses	9,131,849	Power Supply Expenses	9,835,045
Total Working Capital Expenses	10,796,432	**Total Working Capital Expenses**	11,663,954
Working Capital Allowance rate of 15%	1,619,465	Working Capital Allowance rate of 15%	1,749,593

RATE BASE CALCULATION FOR 2010		RATE BASE CALCULATION FOR 2011	
Fixed Assets Opening Balance 2010	4,115,106	Fixed Assets Opening Balance 2011	5,147,592
Fixed Assets Closing Balance 2010	5,147,592	Fixed Assets Closing Balance 2011	5,349,238
Average Fixed Asset Balance - 2010	4,631,349	**Average Fixed Asset Balance for 2011**	5,248,415
Working Capital Allowance	1,619,465	Working Capital Allowance	1,749,593
Rate Base	6,250,814	**Rate Base**	6,998,008
Regulated Rate of Return	6.40%	Regulated Rate of Return	6.40%
Regulated Return on Capital	400,127	**Regulated Return on Capital**	447,957
Deemed Interest Expense	185,849	Deemed Interest Expense	208,065
Deemed Return on Equity	214,278	Deemed Return on Equity	239,892

Table 5.5 – Capital Structure and Rate Base Calculation for 2012

2012		
Description	**Deemed Portion**	**Effective Rate**
Long-Term Debt	56.00%	4.02%
Short-Tern Debt	4.00%	2.08%
Return On Equity	40.00%	9.42%
Weighted Debt Rate		3.89%
Regulated Rate of Return		6.10%

WORKING CAPITAL ALLOWANCE FOR 2012	
Distribution Expenses	
Distribution Expenses - Operation	309,662
Distribution Expenses - Maintenance	411,374
Billing and Collecting	391,300
Community Relations	3,500
Administrative and General Expenses	775,892
Taxes Other than Income Taxes	23,300
Less: Capital Taxes within 6105	
Total Eligible Distribution Expenses	**1,915,028**
Power Supply Expenses	10,499,095
Total Working Capital Expenses	12,414,122
Working Capital Allowance rate of 15%	1,862,118

RATE BASE CALCULATION FOR 2012	
Fixed Assets Opening Balance 2012	5,349,238
Fixed Assets Closing Balance 2012	5,369,839
Average Fixed Asset Balance for 2012	5,359,538
Working Capital Allowance	1,862,118
Rate Base	7,221,657
Regulated Rate of Return	6.10%
Regulated Return on Capital	440,535
Deemed Interest Expense	168,423
Deemed Return on Equity	272,112

Table 5.6

Debt & Capital Cost Structure

Weighted Debt Cost

Description	Debt Holder	Affliated with LDC?	Date of Issuance		Principal	Term (Years)	Rate%	Year Applied to	Interest Cost
Promissory Note	Various	Y	August	2001	1,570,256	Various	4.99%	2008	78,356
Altec Line Truck	Bank of Montreal		December	2009	245,000	8	3.00%	2009	7,350
Smart Meter	Bank of Montreal		July	2009	833,403	Demand	3.00%	2009	25,002
Promissory Note	Township of Edwardsburgh/Cardinal	Y	August	2001	225,000	Demand	4.99%	2009	11,228
Promissory Note	Township of South Dundas	Y	August	2001	938,352	Demand	4.99%	2009	46,824
Equity	Bank of Montreal		August	2001	188,470	10	4.99%	2009	9,405
Altec Line Truck	Bank of Montreal		December	2009	229,688	8	3.00%	2010	6,891
Smart Meter	Bank of Montreal		July	2010	812,568	10	3.00%	2010	24,377
Promissory Note	Township of Edwardsburgh/Cardinal	Y	August	2001	225,000	Demand	4.99%	2010	11,228
Promissory Note	Township of South Dundas	Y	August	2001	938,352	Demand	4.99%	2010	46,824
Equity	Bank of Montreal		August	2001	70,940	10	4.99%	2010	3,540
Altec Line Truck	Bank of Montreal		December	2009	199,063	8	3.00%	2011	5,972
Smart Meter	Bank of Montreal		July	2010	932,129	10	3.00%	2011	27,964
Promissory Note	Township of Edwardsburgh/Cardinal	Y	August	2001	225,000	Demand	4.99%	2011	11,228
Promissory Note	Township of South Dundas	Y	August	2001	938,352	Demand	4.99%	2011	46,824
Posi Plus	Bank of Montreal		September	2011	278,142	8	3.80%	2011	10,569
Altec Line Truck	Bank of Montreal		December	2009	168,438	8	3.00%	2012	5,053
Smart Meter	Bank of Montreal		July	2010	877,841	10	3.00%	2012	26,335
Promissory Note	Township of Edwardsburgh/Cardinal	Y	August	2001	225,000	Demand	4.99%	2012	11,228
Promissory Note	Township of South Dundas	Y	August	2001	938,352	Demand	4.99%	2012	46,824
Smart Meter	Bank of Montreal		August	2001	100,000	10	3.87%	2012	3,870
Posi Plus	Bank of Montreal		September	2011	256,069	8	3.80%	2012	9,731

2008 Total Long Term Debt	1,570,256	Total Interest Cost for 2008	78,356
		Weighted Debt Cost Rate for 2008	4.99%
2009 Total Long Term Debt	2,430,225	Total Interest Cost for 2009	99,808
		Weighted Debt Cost Rate for 2009	4.11%
2010 Total Long Term Debt	2,276,548	Total Interest Cost for 2010	92,859
		Weighted Debt Cost Rate for 2010	4.08%
2011 Total Long Term Debt	2,572,686	Total Interest Cost for 2011	102,556
		Weighted Debt Cost Rate for 2011	3.99%
2012 Total Long Term Debt	2,565,700	Total Interest Cost for 2012	103,040
		Weighted Debt Cost Rate for 2012	4.02%

Exhibit 6 — Calculation of Revenue Deficiency or Sufficiency

1.0 OVERVIEW

RSL's 2012 revenue deficiency is $ 570,329.

This deficiency is calculated as the difference between the 2012 Test Year Revenue Requirement of $2,735,672, and the Forecast 2012 Test Year Revenue Requirement of $2,165,343, as calculated using RSL's 2011 approved distribution rates .

Table 6.1 on the following page provides the revenue deficiency calculations for the 2012 Test Year at Existing 2011 Board-approved rates and the 2012 Test Year Revenue Requirement.

Table 6.1 Revenue Deficiency - MIFRS

Revenue Deficiency Determination			
Description	**2011 Bridge Actual**	**2012 Test Existing Rates**	**2012 Test - Required Revenue**
Revenue			
Revenue Deficiency			**570,329**
Distribution Revenue	1,951,876	1,957,800	1,957,800
Other Operating Revenue (Net)	171,953	207,543	207,543
Total Revenue	**2,123,829**	**2,165,343**	**2,735,672**
Costs and Expenses			
Administrative & General, Billing & Collecting	1,094,764	1,170,692	1,170,692
Operation & Maintenance	711,745	721,036	721,036
Depreciation & Amortization	334,223	340,980	340,980
Property Taxes	22,400	23,300	23,300
Capital Taxes	0	0	0
Deemed Interest	208,065	168,423	168,423
Total Costs and Expenses	**2,371,198**	**2,424,431**	**2,424,431**
Less OCT Included Above	0	0	0
Total Costs and Expenses Net of OCT	**2,371,198**	**2,424,431**	**2,424,431**
Utility Income Before Income Taxes	**-247,369**	**-259,088**	**311,241**
Income Taxes:			
Corporate Income Taxes	-46,251	-49,272	39,129
Total Income Taxes	**-46,251**	**-49,272**	**39,129**
Utility Net Income	**-201,118**	**-209,816**	**272,112**
Capital Tax Expense Calculation:			
Total Rate Base	6,998,008	7,221,657	7,221,657
Exemption	15,000,000	15,000,000	15,000,000
Deemed Taxable Capital	**-8,001,992**	**-7,778,343**	**-7,778,343**
Ontario Capital Tax	0	0	0
Income Tax Expense Calculation:			
Accounting Income	-247,369	-259,088	311,241
Tax Adjustments to Accounting Income	-51,023	-58,797	-58,797
Taxable Income	**-298,392**	**-317,885**	**252,443**
Income Tax Expense	-46,251	-49,272	39,129
Tax Rate Refecting Tax Credits	15.50%	15.50%	15.50%
Actual Return on Rate Base:			
Rate Base	6,998,008	7,221,657	7,221,657
Interest Expense	208,065	168,423	168,423
Net Income	-201,118	-209,816	272,112
Total Actual Return on Rate Base	**6,947**	**-41,393**	**440,535**
Actual Return on Rate Base	0.10%	-0.57%	6.10%
Required Return on Rate Base:			
Rate Base	6,998,008	7,221,657	7,221,657
Return Rates:			
Return on Debt (Weighted)	4.96%	3.89%	3.89%
Return on Equity	8.57%	8.57%	8.57%
Deemed Interest Expense	208,065	168,423	168,423
Return On Equity	239,892	272,112	272,112
Total Return	**447,957**	**440,535**	**440,535**
Expected Return on Rate Base	6.40%	6.10%	6.10%
Revenue Deficiency After Tax	**441,010**	**481,928**	**0**
Revenue Deficiency Before Tax	**521,905**	**570,329**	**0**

Revenue Requirement:

RSL's Revenue Requirement consists of the following:

- Administrative & General, Billing & Collecting Expense
- Operation & Maintenance Expense
- Depreciation Expense
- Property Taxes
- PILS
- Deemed Interest & Return on Equity

RSL's revenue requirement is primarily received through electricity distribution rates and offset by revenue from Board Approved specific service charges, late payment charges, interest, and other operating income.

2.0 COST DRIVERS FOR REVENUE DEFICIENCY

RSL notes there are several factors that contribute to the Revenue Deficiency of $ 570,329 for the Test Year. The list below highlights significant items that contribute to this deficiency.

Labour and Payroll Costs:

Between 2008 and 2011, no incremental additions were made to the staff complement approved as part of our 2008 COS. For 2012 RSL plans to add a Regulatory Analyst, and have included this cost in our account 5655 Regulatory Expenses. All costs for the Rate Application have increased from 2008, resulting in a Test Year Forecast increase of about $100,000.

RSL has also experienced increased benefit costs, and negotiated contract wage increases that were in excess of the increase allowed through the IRM process.

Further details can be found in Exhibit 4.

Depreciation:

The addition of $1,294,090 in smart meter assets has added 25% to the Rate base of RSL, and increased depreciation expense of $110,122. The Smart Meters have also increased RSL's Revenue Requirement by almost $265,000.

In 2011, RSL replaced the third and last of its line trucks. All units replaced, had been in service with RSL or its former PUC's for at least 20 years. All units had been fully depreciated, except for the Altec unit added in 2008, for which only a half years depreciation expense was included in our Approved Rates. As a result, depreciation expense for our line trucks has increased by over $50,000 from our 2008 COS.

Modified IFRS:

RSL adopted the Typical Useful Life from the Kinectrics study, and this resulted in a depreciation decrease for 2012 of $71,406, plus $22,073 for ¼ of the 2011 reduction ($88,291) when restating in MIFRS format, compared to what it would have been under CGAAP. Table 6.2 below provides a comparison of the depreciation rates that were used for CGAAP, and the rates that have been used for 2012 Rate Application in MIFRS format.

Overall, the 2012 Test Year Depreciation Expense has a net increase over 2008 of $111,984, even after the reduction for moving to the TUL.

RSL did not include administration costs in Capital, so there was no cost change/driver for the move to MIFRS.

Table 6.2

CGAAP vs. Kinectrics TUL Depreciation Comparison for 2012

CCA Class	OEB	Description	Exclude Fully Amort	Opening Balance	Additions	Disposals	Closing Balance	Years CGAAP	TUL MIFRS	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value
N/A	1610	Intangible Assets		0			0			0			0	0
N/A	1805	Land		84,205			84,205	n/a	n/a	0			0	84,205
CEC	1806	Land Rights		0			0			0			0	0
47	1808	Buildings and Fixtures		82,287	7,690		89,977	50	50	8,294	1,723		10,017	79,961
13	1810	Leasehold Improvements		0			0			0	-		0	0
47	1820	1820 - Wholesale meters, normally incl below		326,992	15,000		341,992	25	25	64,899	13,380		78,279	263,713
47	1820	Distribution Station Equipment - Normally Primary belo		397,892	20,000		417,892	25	45	138,810	9,064		147,874	270,018
47	1860	Smart Meters		1,294,090			1,294,090	model	model	220,715	110,121		330,836	963,253
47	1830	Poles, Towers and Fixtures		502,092	72,310		574,402	25	45	94,688	11,961		106,649	467,753
47	1835	Overhead Conductors and Devices		1,839,430	50,000		1,889,430	25	60	659,734	31,074		690,808	1,198,622
47	1840	Underground Conduit		36,862			36,862	25	50	10,414	737		11,151	25,712
47	1845	Underground Conductors and Devices		797,248	20,000		817,248	25	40	293,470	20,181		313,651	503,597
47	1850	Line Transformers		1,031,223	60,000		1,091,223	25	45	295,255	23,583		318,838	772,385
47	1855	Services		281,637	20,000		301,637	25	60	49,116	4,861		53,977	247,660
47	1860	Meters		176,155	40,000		216,155	25	25	30,866	7,846		38,712	177,443
N/A	1865	Other Installations on Customer's Premises		0			0			0			0	0
N/A	1905	Land		0			0			0			0	0
CEC	1906	Land Rights		0			0			0			0	0
47	1908	Buildings and Fixtures		0			0			0			0	0
13	1910	Leasehold Improvements		8,796			8,796	10	10	3,079	880		3,959	4,838
8	1915	Office Furniture and Equipment		0			0			0			0	0
10	1920	Computer Equipment - Hardware	(92,556)	163,688	20,000		183,688	5	5	127,137	16,226		143,363	40,325
12	1925	Computer Software	(11,546)	164,827	50,000		214,827	5	5	92,250	35,656		127,906	86,921
10	1930	Transportation Equipment		627,095			627,095	8	8	130,420	78,387		208,807	418,289
8	1935	Stores Equipment		0			0			0	-		0	0
8	1940	Tools, Shop and Garage Equipment	(75,572)	137,984	10,000		147,984	10	10	111,146	6,741		117,887	30,097
8	1945	Measurement and Testing Equipment		0			0			0	-		0	0
8	1950	Power Operated Equipment		0			0			0	-		0	0
8	1955	Communication Equipment		0			0			0	-		0	0
8	1960	Miscellaneous Equipment		0			0			0	-		0	0
47	1990	Other Tangible Property		0			0		Average	0	-		0	0
47	1995	Contributions and Grants		(360,988)			(360,988)	25	45	(88,013)	- 8,022		(96,035)	(264,953)
	2005	Property under Capital Lease		0			0			0			0	0
		Total before Work in Process	**(179,675)**	**7,591,516**	**385,000**	**0**	**7,976,516**			**2,242,278**	**364,399**	**0**	**2,606,677**	**5,369,839**
WIP		Work in Process		0			0			0			0	0
		Total after Work in Process	**(179,675)**	**7,591,516**	**385,000**	**0**	**7,976,516**			**2,242,278**	**364,399**	**0**	**2,606,677**	**5,369,839**

OM&A:

OM&A includes the costs for a Regulatory Analyst, for the 2012 COS Rate Application, and for increased Regulatory Reporting. Also, costs in account 5065 have increased in the amount of $82,473 for the incremental Smart Meter OM&A costs.

MDMR costs have not been included in this application, and will be submitted for recovery once the OEB advises the process to follow in submitting an application to recover MDMR costs.

Revenue Requirement Comparison – MIFRS vs. CGAAP

As required by the Canadian Accounting Standards Board (AcSB) Canadian Generally Accepted Accounting Principles (CGAAP) will be replaced by IFRS for rate-regulated enterprises effective January 1, 2012.

The Board issued EB-2008-0408 on June 13, 2011 as an Addendum to the Report of the Board for Implementing MIFRS. As part of the transition to MIFRS, RSL is required to restate 2011 results in MIFRS, and record the difference in a variance account. RSL's variance in restating 2011 in MIFRS format is a reduction in depreciation expense of $88,291.

Table 6.3 below shows a Revenue Deficiency under CGAAP of $693,989, as compared to the Revenue Deficiency under MIFRS of $570,329. The main driver for this Revenue Deficiency in 2012 is the reduction of $115,841 in depreciation expense for 2012.

Table 6.3

Revenue Deficiency – CGAAP

Description	2011 Bridge Actual	2012 Test Existing Rates	2012 Test - Required Revenue
Revenue			
Revenue Deficiency			**693,988.77**
Distribution Revenue	1,975,016	1,957,800	1,957,800
Other Operating Revenue (Net)	171,953	207,543	207,543
Total Revenue	**2,146,969**	**2,165,343**	**2,859,332**
Costs and Expenses			
Administrative & General, Billing & Collecting	1,094,764	1,170,692	1,170,692
Operation & Maintenance	711,745	721,036	721,036
Depreciation & Amortization	422,514	456,821	456,821
Property Taxes	22,400	23,300	23,300
Capital Taxes	0	0	0
Deemed Interest	167,669	165,286	165,286
Total Costs and Expenses	**2,419,092**	**2,537,136**	**2,537,136**
Less OCT Included Above	0	0	0
Total Costs and Expenses Net of OCT	**2,419,092**	**2,537,136**	**2,537,136**
Utility Income Before Income Taxes	**-272,123**	**-371,793**	**322,196**
Income Taxes:			
Corporate Income Taxes	-36,403	-52,416	55,152
Total Income Taxes	**-36,403**	**-52,416**	**55,152**
Utility Net Income	**-235,721**	**-319,377**	**267,044**
Capital Tax Expense Calculation:			
Total Rate Base	6,953,863	7,087,155	7,087,155
Exemption	15,000,000	15,000,000	15,000,000
Deemed Taxable Capital	**-8,046,137**	**-7,912,845**	**-7,912,845**
Ontario Capital Tax	0	0	0
Income Tax Expense Calculation:			
Accounting Income	-272,123	-371,793	322,196
Tax Adjustments to Accounting Income	37,268	33,625	33,625
Taxable Income	**-234,856**	**-338,168**	**355,821**
Income Tax Expense	-36,403	-52,416	55,152
Tax Rate Refecting Tax Credits	15.50%	15.50%	15.50%
Actual Return on Rate Base:			
Rate Base	6,953,863	7,087,155	7,087,155
Interest Expense	167,669	165,286	165,286
Net Income	-235,721	-319,377	267,044
Total Actual Return on Rate Base	**-68,052**	**-154,090**	**432,330**
Actual Return on Rate Base	-0.98%	-2.17%	6.10%
Required Return on Rate Base:			
Rate Base	6,953,863	7,087,155	7,087,155
Return Rates:			
Return on Debt (Weighted)	4.02%	3.89%	3.89%
Return on Equity	8.57%	8.57%	8.57%
Deemed Interest Expense	167,669	165,286	165,286
Return On Equity	238,378	267,044	267,044
Total Return	**406,047**	**432,330**	**432,330**
Expected Return on Rate Base	5.84%	6.10%	6.10%
Revenue Deficiency After Tax	**474,099**	**586,421**	**-0**
Revenue Deficiency Before Tax	**561,064**	**693,989**	**-0**

<u>Exhibit 7</u> <u>Cost Allocation</u>

Schedule	Contents of Schedule
1.0	COST ALLOCATION OVERVIEW
2.0	INITIAL COST ALLOCATION STUDY RESULTS
3.0	2012 UPDATED COST ALLOCATION STUDY RESULTS

1.0 COST ALLOCATION OVERVIEW

Introduction:

On September 29, 2006, the OEB issued its original directions on Cost Allocation Methodology for Electricity Distributors (the "Directions"). On November 15, 2006, the Board issued the original Cost Allocation Information Filing Guidelines for Electricity Distributors ("the Guidelines"), the Cost Allocation Model (the "Model") and User Instructions (the "Instructions") for the Model. RSL prepared and filed its 2008 cost allocation information filing consistent with RSL's understanding of the Directions, the Guidelines, the revised Model and the Instructions.

One of the main objectives of the filing was to provide information on any apparent cross-subsidization among a distributor's rate classifications. It was felt that this would give an indication of cross-subsidization from one class to another and this information would be useful as a tool in future rate applications.

RSL has used the Board-approved Cost Allocation model and methodology and updated the values from the Hydro One Run 3 load forecast using 2011 and 2012 weather normalized forecasted data information.

2.0 INITIAL COST ALLOCATION STUDY RESULTS

The results of the original Cost Allocation Model, was used by RSL to support its 2008 OEB-approved distribution rates. Consistent with the Guidelines, RSL's assets were broken out into primary and secondary distribution functions. The breakout of assets, capital contributions, depreciation, accumulated depreciation, customer data and load data by primary, line transformer and secondary categories were developed from the best data available to RSL, its engineering records, and its customer and financial information systems.

As noted above, the results of a cost allocation study are typically presented in the form of revenue to cost ratios. The ratio is shown by rate classification and is the percentage of distribution revenue collected by rate classification compared to the costs allocated to the classification. The percentage identifies the rate classifications that are being subsidized and those that are over-contributing. A percentage of less than 100% means the rate classification is under-contributing and is being subsidized by other classes of customers. A percentage of greater than 100% indicates the rate classification is over-contributing and is subsidizing other classes of customers.

The following Table 7.1 outlines the revenue to cost ratios submitted with RSL's 2008 Cost of Service Rate Application.

In the Board's decision, on RSL's 2008 Rate Application EB-2007-0762, RSL was instructed to increase the Street Light revenue to cost ratio to 56% in 2008, and to 70% in 2009.

The Street Light revenue to cost ratio was increased in 2008, and then to the 70% in 2009, as required in the Board's decision.

Table 7.1

Revenue to Cost Ratios - 2008 Cost Allocation Filing

		1	2	3	7	8	9
	Total	Residential	GS < 50KW	GS > 50KW	Street Lighting	Sentinel Lighting	Unmetered Scattered Load
Distribution Revenue (sale)	$1,563,507	$909,886	$207,579	$389,654	$39,300	$1,513	$15,575
Miscellaneous Revenue (mi)	$162,559	$99,452	$38,375	$21,474	$1,051	$86	$2,121
Total Revenue	$1,726,066	$1,009,338	$245,954	$411,128	$40,351	$1,599	$17,696
Expenses							
Distribution Costs (di)	$366,237	$194,311	$67,617	$70,151	$31,999	$1,096	$1,062
Customer Related Costs (cu)	$372,106	$228,778	$101,407	$31,236	$5,250	$139	$5,296
General and Administration (ad)	$485,368	$276,786	$110,364	$68,456	$24,897	$827	$4,038
Depreciation and Amortization (dep)	$156,359	$81,216	$30,561	$32,575	$11,224	$385	$397
PILs (INPUT)	$29,643	$15,247	$5,819	$6,415	$2,022	$69	$71
Interest	$96,324	$49,545	$18,907	$20,844	$6,571	$226	$231
Total Expenses	$1,506,036	$845,884	$334,675	$229,677	$81,963	$2,742	$11,095
Direct Allocation	$0	$0	$0	$0	$0	$0	$0
Allocated Net Income (NI)	$220,030	$113,175	$43,189	$47,614	$15,010	$516	$527
Revenue Requirement (includes NI)	$1,726,066	$959,059	$377,864	$277,290	$96,974	$3,258	$11,622
	Revenue Requirement Input equals Output						
Rate Base Calculation							
Net Assets							
Distribution Plant - Gross	$3,926,040	$2,025,750	$767,273	$838,676	$275,311	$9,456	$9,574
General Plant - Gross	$142,228	$73,352	$27,831	$30,412	$9,944	$342	$347
Accumulated Depreciation	($518,349)	($268,282)	($100,461)	($110,027)	($37,049)	($1,270)	($1,259)
Capital Contribution	($162,847)	($88,521)	($29,861)	($26,339)	($16,994)	($582)	($549)
Total Net Plant	$3,387,072	$1,742,299	$664,781	$732,722	$231,212	$7,946	$8,112
Directly Allocated Net Fixed Assets	$0	$0	$0	$0	$0	$0	$0
Cost of Power (COP)	$8,669,874	$3,042,708	$1,565,163	$3,946,204	$90,954	$3,476	$21,368
OM&A Expenses	$1,223,710	$699,875	$279,388	$169,842	$62,146	$2,062	$10,396
Directly Allocated Expenses	$0	$0	$0	$0	$0	$0	$0
Subtotal	$9,893,584	$3,742,584	$1,844,551	$4,116,046	$153,100	$5,538	$31,764
Working Capital	$1,484,038	$561,388	$276,683	$617,407	$22,965	$831	$4,765
Total Rate Base	$4,871,109	$2,303,687	$941,464	$1,350,129	$254,177	$8,777	$12,877
	Rate Base Input equals Output						
Equity Component of Rate Base	$2,435,555	$1,151,843	$470,732	$675,064	$127,088	$4,388	$6,439
Net Income on Allocated Assets	$220,030	$163,454	($88,721)	$181,451	($41,612)	($1,143)	$6,601
Net Income on Direct Allocation Assets	$0	$0	$0	$0	$0	$0	$0
Net Income	$220,030	$163,454	($88,721)	$181,451	($41,612)	($1,143)	$6,601
RATIOS ANALYSIS							
REVENUE TO EXPENSES %	100.00%	105.24%	65.09%	148.27%	41.61%	49.08%	152.26%
EXISTING REVENUE MINUS ALLOCATED COSTS	($0)	$50,279	($131,910)	$133,838	($56,622)	($1,659)	$6,074
RETURN ON EQUITY COMPONENT OF RATE BASE	9.03%	14.19%	-18.85%	26.88%	-32.74%	-26.04%	102.52%

3.0 2012 UPDATED COST ALLOCATION STUDY RESULTS

On August 5, 2011 the Board issued its revised cost allocation model, to reflect the changes required to implement the revisions to the Board policy as set out in the “Report of the Board: Review of Electricity Distribution Cost Allocation Policy, issued on March 31, 2011. On August 5, 2011 the Board issued a revised cost allocation model that reflects changes required to implement the revisions to the Board’s policy as set out in the “Report of the Board: Review of Electricity Distribution Coast Allocation Policy (EB-2010-0219).

RSL used the above guidelines in completing the updated Board-approved Cost Allocation Model in entering RSL’s 2012 data.

RSL populated the information on Sheet I3, Trial Balance Data with the 2012 forecasted data based on the 2011 and 2012 average and input the Target Net Income, PILs, Deemed interest on long term debt, specific service charges information and the targeted revenue requirement and rate base.

On Sheet I4, Break-out of Assets, RSL updated the allocation of the accounts based on 2012 values.

In Sheet I5.1, Miscellaneous data, RSL updated the deemed equity component of rate base and the monthly service charges.

In Sheet I5.2, Weighting Factors, RSL has used the default weighting factors for the Cost Allocation Informational Filing, and RSL believes that these are appropriate as RSL does not have utility specific weighting factors available for this rate application.

In Sheet I6.1 Revenue has been populated with the 2012 Test year forecast data.

RSL inserted sheet “Meter Capital Cost Analysis” in the model to provide an updated allocation including the smart meters, and excluding the stranded meters. The weighting factor used for meters, was based on the average cost for residential ($92.32 or 68% of the total smart meter costs) and for commercial ($252.40 per meter, or 32% of the total meter cost). For the rest of the project costs (supporting networks, systems and servers etc.) the costs were allocated based on customer count, or 86.7% residential, and 13.3% commercial. This provided an overall smart meter project cost of 75.9% for residential meters, and 24.1% for commercial meters. The smart meter Capital project cost of $1,294,090 was split in the cost allocation model based on these percentages - $982,520 to residential, and $311,570 to commercial accounts. The legacy Industrial meter NBV of $216,155 was all assigned to the Industrial class.

The updated and allocated capital meter cost determined above, was entered on Sheet I7.1 and the meter reading information on I7.2.

On sheet I8, Demand data is based on the output of our load forecast model. The load profile from the 2004 data received from Hydro One, Run 3 and the weather normalized 2012 forecast data was used to calculate the 1 NCP, 4 NCP, 12 NCP, 1 CP, 4 CP and the 12CP demand data. No direct allocations were used.

The revenue to cost ratios for the 2012 updated study is provided in Table 7.5 below;

Table 7.2

Cost Allocation – 2012 Load Data at Existing Rates (I-6.1)

Total kWhs from Load Forecast	104,537,301
Total kWs from Load Forecast	130,796
Deficiency from RRWF	- 570,329
Miscellaneous Revenue	207,543

	ID	Total	1 Residential	2 General Service Less than 50 kW	3 General Service 50 to 4,999 kW	7 Street Lighting	8 Sentinel Lighting	9 Unmetered Scattered Load
Billing Data								
Forecast kWh	CEN	104,537,301	44,584,446	19,806,495	38,166,401	1,441,722	108,277	429,961
Forecast kW	CDEM	130,796			126,652	3,843	301	
Forecast kW, included in CDEM, of customers receiving line transformer allowance		62,908			62,908			
Optional - Forecast kWh, included in CEN, from customers that receive a line transformation allowance on a kWh basis. In most cases this will not be applicable and will be left blank.		-						
KWh excluding KWh from Wholesale Market Participants	CEN EWMP	104,537,301	44,584,446	19,806,495	38,166,401	1,441,722	108,277	429,961
kWh - 30 year weather normalized amount	Click here to	-	-	-	-	-	-	-
Existing Monthly Charge			$10.28	$24.34	$281.39	$2.29	$1.24	$7.41
Existing Distribution kWh Rate			$0.0117	$0.0074				$0.0340
Existing Distribution kW Rate					$1.2473	$8.7393	$9.0716	
Existing TFOA Rate			$0.60	$0.60	$0.60	$0.60	$0.60	$0.60
Additional Charges								
Distribution Revenue from Rates		$1,995,545	$1,140,450	$371,470	$379,497	$80,544	$3,846	$19,737
Transformer Ownership Allowance		$37,745	$0	$0	$37,745	$0	$0	$0
Net Class Revenue	CREV	$1,957,800	$1,140,450	$371,470	$341,752	$80,544	$3,846	$19,737

Table 7.3

Demand Data Worksheet (I-8)

CP TEST RESULTS	4 CP
NCP TEST RESULTS	4 NCP

Co-incident Peak	Indicator
1 CP	CP 1
4 CP	CP 4
12 CP	CP 12

Non-co-incident Peak	Indicator
1 NCP	NCP 1
4 NCP	NCP 4
12 NCP	NCP 12

			1	2	3	7	8	9
Customer Classes		Total	Residential	General Service Less than 50 kW	General Service 50 to 4,999 kW	Street Lighting	Sentinel Lighting	Unmetered Scattered Load
CO-INCIDENT PEAK								
1 CP								
Transformation CP	TCP1	20,771	9,474	2,163	8,735	332	25	43
Bulk Delivery CP	BCP1	20,771	9,474	2,163	8,735	332	25	43
Total Sytem CP	DCP1	20,771	9,474	2,163	8,735	332	25	43
4 CP								
Transformation CP	TCP4	76,463	35,927	11,117	28,063	1,078	81	197
Bulk Delivery CP	BCP4	76,463	35,927	11,117	28,063	1,078	81	197
Total Sytem CP	DCP4	76,463	35,927	11,117	28,063	1,078	81	197
12 CP								
Transformation CP	TCP12	194,297	88,121	32,015	71,701	1,742	131	587
Bulk Delivery CP	BCP12	194,297	88,121	32,015	71,701	1,742	131	587
Total Sytem CP	DCP12	194,297	88,121	32,015	71,701	1,742	131	587
NON CO_INCIDENT PEAK								
1 NCP								
Classification NCP from Load Data Provider	DNCP1	24,950	11,598	3,862	9,078	332	25	55
Primary NCP	PNCP1	24,950	11,598	3,862	9,078	332	25	55
Line Transformer NCP	LTNCP1	22,874	11,598	3,862	7,002	332	25	55
Secondary NCP	SNCP1	24,950	11,598	3,862	9,078	332	25	55
4 NCP								
Classification NCP from Load Data Provider	DNCP4	95,459	45,059	14,598	34,161	1,327	100	214
Primary NCP	PNCP4	95,459	45,059	14,598	34,161	1,327	100	214
Line Transformer NCP	LTNCP4	87,649	45,059	14,598	26,350	1,327	100	214
Secondary NCP	SNCP4	95,459	45,059	14,598	34,161	1,327	100	214
12 NCP								
Classification NCP from Load Data Provider	DNCP12	239,784	107,314	40,893	86,709	3,982	299	587
Primary NCP	PNCP12	239,784	107,314	40,893	86,709	3,982	299	587
Line Transformer NCP	LTNCP12	219,958	107,314	40,893	66,883	3,982	299	587
Secondary NCP	SNCP12	239,784	107,314	40,893	86,709	3,982	299	587

Table 7.4

Revenue to Cost Ratios from RSL's Updated 2012 Cost Allocation Model

		1	2	3	7	8	9
	Total	Residential	General Service Less than 50 kW	General Service 50 to 4,999 kW	Street Lighting	Sentinel Lighting	Unmetered Scattered Load
Distribution Revenue at Existing Rates	$1,957,800	$1,140,450	$371,470	$341,752	$80,544	$3,846	$19,737
Miscellaneous Revenue (mi)	$207,543	$119,411	$36,535	$35,433	$12,922	$588	$2,654
	Miscellaneous Revenue Input equals Output						
Total Revenue at Existing Rates	$2,165,343	**$1,259,861**	**$408,005**	**$377,186**	**$93,466**	**$4,434**	**$22,391**
Factor required to recover deficiency (1 + D)	1.2913						
Distribution Revenue at Status Quo Rates	$2,528,129	$1,472,676	$479,683	$441,309	$104,007	$4,967	$25,487
Miscellaneous Revenue (mi)	$207,543	$119,411	$36,535	$35,433	$12,922	$588	$2,654
Total Revenue at Status Quo Rates	$2,735,672	**$1,592,087**	**$516,218**	**$476,742**	**$116,929**	**$5,555**	**$28,141**
Expenses							
Distribution Costs (di)	$603,563	$312,633	$87,707	$145,316	$53,248	$2,339	$2,319
Customer Related Costs (cu)	$508,773	$323,406	$110,166	$59,661	$1,081	$168	$14,291
General and Administration (ad)	$802,692	$457,694	$141,730	$150,488	$39,764	$1,828	$11,189
Depreciation and Amortization (dep)	$340,980	$183,258	$50,916	$80,326	$24,305	$1,070	$1,104
PILs (INPUT)	$39,129	$21,610	$6,346	$8,798	$2,176	$97	$103
Interest	$168,423	$93,017	$27,313	$37,868	$9,367	$416	$442
Total Expenses	$2,463,560	**$1,391,618**	**$424,179**	**$482,456**	**$129,942**	**$5,917**	**$29,447**
Direct Allocation	$0	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
Allocated Net Income (NI)	$272,112	$150,282	$44,129	$61,181	$15,134	$671	$714
Revenue Requirement (includes NI)	$2,735,672	$1,541,901	$468,308	$543,638	$145,077	$6,588	$30,161
	Revenue Requirement Input equals Output						
Rate Base Calculation							
Net Assets							
Distribution Plant - Gross	$7,002,613	$3,818,683	$1,095,054	$1,606,406	$442,450	$19,556	$20,464
General Plant - Gross	$1,142,390	$630,415	$184,231	$254,942	$66,739	$2,957	$3,106
Accumulated Depreciation	($2,424,477)	($1,292,969)	($358,130)	($587,282)	($170,707)	($7,519)	($7,871)
Capital Contribution	($360,988)	($196,548)	($52,793)	($70,519)	($37,908)	($1,664)	($1,557)
Total Net Plant	$5,359,538	**$2,959,582**	**$868,363**	**$1,203,548**	**$300,573**	**$13,331**	**$14,142**
Directly Allocated Net Fixed Assets	$0	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
Cost of Power (COP)	$10,499,095	$4,477,792	$1,989,245	$3,833,203	$144,798	$10,875	$43,183
OM&A Expenses	$1,915,028	$1,093,733	$339,603	$355,464	$94,094	$4,335	$27,798
Directly Allocated Expenses	$0	$0	$0	$0	$0	$0	$0
Subtotal	*$12,414,122*	***$5,571,525***	***$2,328,848***	***$4,188,667***	***$238,892***	***$15,210***	***$70,981***
Working Capital	$1,862,118	**$835,729**	**$349,327**	**$628,300**	**$35,834**	**$2,281**	**$10,647**
Total Rate Base	$7,221,656	**$3,795,310**	**$1,217,690**	**$1,831,848**	**$336,407**	**$15,612**	**$24,789**
	Rate Base Input equals Output						
Equity Component of Rate Base	$2,888,663	**$1,518,124**	**$487,076**	**$732,739**	**$134,563**	**$6,245**	**$9,916**
Net Income on Allocated Assets	$272,112	**$200,469**	**$92,039**	**($5,715)**	**($13,013)**	**($362)**	**($1,306)**
Net Income on Direct Allocation Assets	$0	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
Net Income	$272,112	**$200,469**	**$92,039**	**($5,715)**	**($13,013)**	**($362)**	**($1,306)**
RATIOS ANALYSIS							
REVENUE TO EXPENSES STATUS QUO%	100.00%	**103.25%**	**110.23%**	**87.69%**	**80.60%**	**84.31%**	**93.30%**
EXISTING REVENUE MINUS ALLOCATED COSTS	($570,329)	($282,039)	($60,303)	($166,452)	($51,611)	($2,154)	($7,769)
	Deficiency Input equals Output						
STATUS QUO REVENUE MINUS ALLOCATED COSTS	$0	$50,186	$47,911	($66,896)	($28,148)	($1,034)	($2,019)
RETURN ON EQUITY COMPONENT OF RATE BASE	9.42%	13.21%	18.90%	-0.78%	-9.67%	-5.80%	-13.17%

Table 7.5

Minimum and Maximum Monthly Fixed Charge per CA Model (O-2)

	1	2	3	7	8	9
Summary	Residential	General Service Less than 50 kW	General Service 50 to 4,999 kW	Street Lighting	Sentinel Lighting	Unmetered Scattered Load
Customer Unit Cost per month - Avoided Cost	$6.16	$13.53	$81.13	$0.03	$0.16	$20.51
Customer Unit Cost per month - Directly Related	$10.09	$22.34	$135.18	$0.07	$0.30	$34.44
Customer Unit Cost per month - Minimum System with PLCC Adjustment	$16.67	$31.24	$180.38	$7.03	$7.26	$39.94
Existing Approved Fixed Charge	$10.28	$24.34	$281.39	$2.29	$1.24	$7.41

Proposed Adjustment to Cost Allocation:

On November 28, 2007, the OEB issued its “Report on Application of Cost Allocation for Electricity Distributors” (the “Cost Allocation Report”). In the Cost Allocation Report, the OEB established what it considered to be the appropriate ranges of revenue to cost ratios which are summarized in Table 7.3 below. In 2011 the Board changed some of those ranges such as the Sentinel Light and GS > 50kW customer classes which have been taken into consideration in the Table 7.6. Table 7.6 also provides RSL’s proposed 2012 revenue to cost ratios.

RSL is proposing in this application to re-align its revenue to cost ratios by adjusting the allocations of revenue among rate classes in order to reduce some of the cross-subsidization that is occurring, and as a means to reduce the bill impact on Residential customers. The proposed re-alignment moves the Residential, and the GS > 50kW classes closer to 100. Residential has a 1.25% decrease, while GS > 50kW has a 3.56% increase from that proposed by the Cost Allocation Model.

The reduction to the Residential class, brings the revenue to cost ratio closer to 100%, and reduces the bill impact for the change requested in our 2012 COS Rate Application.

Table 7.6

RSL's Proposed Revenue to Cost Ratios

			Board Target	
	Updated OEB Cost Allocation Model	**Proposed Revenue to Cost Ratios**	**Low**	**High**
Residential	103.25	102.00	85	115
GS < 50kW	110.23	110.23	80	120
GS > 50kW	87.69	91.25	80	120
Sentinel Lighting	84.31	84.31	80	120
Street Lighting	80.60	80.60	70	120
USL	93.30	93.30	80	120

Table 7.7 outlines the revenue splits required to achieve the proposed revenue to cost ratios:

Table 7.7

Revenue Split by Rate Class to Achieve Proposed R/C Ratios	
Customer Class	Revenue Requirement %
Residential	57.49%
GS < 50kW	18.97%
GS > 50kW	18.22%
Sentinel Lighting	0.20%
Street Lighting	4.11%
USL	1.01%

Cost Allocation Summary:

The discussion and tables above support RSL's proposed reallocation of distribution revenues across customer classes in accordance with Board directions - moving toward revenue to cost ratios of 100% and to reduce cross-subsidization.

RSL submits that the proposed reallocation of distribution revenue is fair and reasonable and customer class revenues will more closely reflect the actual costs of providing distribution service to that class.

Exhibit 8 — Rate Design

Schedule	Contents of Schedule
1.0	RATE DESIGN OVERVIEW
1.1	Fixed/Variable Proportion:
2.0	RETAIL TRANSMISSION SERVICE RATES (RTSR)
3.0	RETAIL SERVICE CHARGES
4.0	WHOLESALE MARKET SERVICE CHARGES
5.0	SPECIFIC SERVICE CHARGES
6.0	LOW VOLTAGE CHARGES
7.0	DETERMINATION OF LOSS ADJUSTMENT FACTORS
8.0	RATE SCHEDULES
9.0	BILL IMPACT INFORMATION
10.0	RATE MITIGATION

1.0 RATE DESIGN OVERVIEW

This Exhibit documents the calculation of RSL's proposed distribution rates by rate class for the 2012 test year, based on rate design as proposed in this Exhibit.

RSL has determined its total 2012 service revenue requirement to be $ $2,735,672 The total revenue offsets in the amount of $ $207,543 reduce RSL's total service revenue requirement to a base revenue requirement to $ $2,528,129 which is used to determine the proposed distribution rates. The base revenue requirement is derived from RSL's 2012 capital and operating forecasts, weather normalized usage, forecasted customer counts, and RSL's regulated return on rate base. The revenue requirements are summarized below in Table 8.1:

RSL is proposing to retain its existing rate structure – no changes requested.

Table 8.1

Calculation of Base Revenue Requirement

OM&A Expenses	1,915,028
Amortization Expenses	340,980
Total Distribution Expenses	**2,256,008**
Regulated Return On Capital	440,535
PILs	39,129
Service Revenue Requirement	**2,735,672**
Less: Revenue Offsets	207,543
Base Revenue Requirement	2,528,129

The outstanding base revenue requirement is allocated to the various rate classes using the following proposed apportionment of revenue as outlined in Exhibit 7 – Cost Allocation.

Table 8.2

Proposed Apportionment of Revenue to Rate Classes

Customer Class	Revenue Requirement %
Residential	57.49%
GS < 50kW	18.97%
GS > 50kW	18.22%
Sentinel Lighting	0.20%
Street Lighting	4.11%
USL	1.01%

The following Table 8.3 outlines the results of this allocation.

Table 8.3

Allocation of Outstanding Base Revenue Requirement

Customer Class	Proposed Revenue
Residential	1,453,328
GS < 50kW	479,683
GS > 50kW	460,657
Sentinel Lighting	4,967
Street Lighting	104,007
USL	25,487
Total	**2,528,129**

1.1 Fixed/Variable Proportion:

Determination of Monthly Fixed/Volumetric Charges:

RSL's current OEB-approved monthly fixed charges and volumetric charges are provided in Table 8.4 and Table 8.5 below:

Table 8.4

Rideau St. Lawrence Distribution Inc. Current Monthly Fixed Charges

Rate Class	Current Monthly Fixed Charge	Customer / Connection
Residential	$ 10.28	Customer
GS < 50kW	$ 24.34	Customer
GS > 50kW	$ 281.39	Customer
Sentinel Lighting	$ 1.24	Connection
Street Lighting	$ 2.29	Connection
USL	$ 7.41	Customer

Table 8.5

Rideau St. Lawrence Distribution Inc. Current Volumetric Charges

Rate Class	Current Variable Charge		kW / kWh
Residential	$	0.0117	kWh
GS < 50kW	$	0.0074	kWh
GS > 50kW	$	1.2473	kW
Sentinel Lighting	$	9.0716	kW
Street Lighting	$	8.7393	kW
USL	$	0.0340	kWh

Table 8.6 below provides the existing Fixed/Variable splits for each of the customer classes.

Table 8.6

Existing Fixed and Variable Splits

Customer Class	Current Volumetric Split	Current Fixed Charge Spilt
Residential	45.74%	54.26%
GS < 50 kW	39.46%	60.54%
GS 50 - 4,999 kW	35.18%	64.82%
Sentinel Lights	70.99%	29.01%
Street Lighting	41.70%	58.30%
USL	74.07%	25.93%

RSL submits that it is appropriate for 2012 to maintain the same fixed/variable proportions assumed in the current rates for all customer classifications.

Proposed Fixed Charges:

Table 8.7 below provides the proposed fixed distribution charges based on the proposed fixed revenue proportion:

Table 8.7

Proposed Monthly Distribution Fixed Service Charge

Customer Class	Total Base Revenue Requirement	Fixed Revenue Proportion	2012 Test Year Customers	Proposed Fixed Charge
Residential	1,453,328	54.26%	5,016	$ 13.10
GS < 50kW	479,683	60.54%	770	$ 31.43
GS > 50kW	460,657	64.82%	66	$ 379.29
Sentinel Lighting	4,967	29.01%	75	$ 1.60
Street Lighting	104,007	58.30%	1,709	$ 2.96
USL	25,487	25.93%	58	$ 9.57
Total	**2,528,129**			

Proposed Volumetric Charges:

The variable distribution charge is calculated by dividing the variable distribution portion of the base revenue requirement by the appropriate 2012 Test Year usage, kWh or kW, as the class charge determinant.

The following Table 8.8 provides RSL's calculations of its proposed variable distribution charges for the 2012 Test Year assuming the same fixed/variable split used in designing the current approved rates.

Table 8.8

Variable Distribution Charge Calculation

Customer Class	Total Base Revenue Requirement	Variable Revenue Proportion	Transformer Allowance	2012 Volumes	Unit	Proposed Volumetric Charge
Residential	1,453,328	45.74%		44,584,446	**kWh**	$ 0.0149
GS < 50kW	479,683	39.46%		19,806,495	**kWh**	$ 0.0096
GS > 50kW	460,657	35.18%	37,745	126,652	**kW**	$ 1.5776
Sentinel Lighting	4,967	70.99%		301	**kW**	$ 11.7143
Street Lighting	104,007	41.70%		3,843	**kW**	$ 11.2852
USL	25,487	74.07%		429,961	**kWh**	$ 0.0439
Total	**2,528,129**					

2.0 RETAIL TRANSMISSION SERVICE RATES (RTSR)

RSL has completed the RTSR Workform Excel file provided by the OEB and has used the resulting rates for bill impact comparison purposes. The total calculated cost from the RTSR workform model for both Network and Connection has been used in the Cost of Power calculation and subsequent working capital calculation.

RSL is proposing the revised rates calculated by the model be used with an effective date of May 1, 2012.

RSL is aware that the proposed Retail Transmission rates should be subject to any modifications as a result of an expected OEB decision on Hydro One Networks' 2012 Uniform Transmission Rate Adjustment Application January 1, 2012.

The entire RTSR Workform Excel Model is included with this rate application.

The following table from the OEB RTSR workform model shows the revised Network and Connection rates.

Table 8.9

Retail Transmission Service Rates (RTSR)

Rate Class	Unit	Proposed RTSR Network	Proposed RTSR Connection
Residential	kWh	$ 0.0058	$ 0.0048
General Service Less Than 50 kW	kWh	$ 0.0053	$ 0.0044
General Service 50 to 4,999 kW	kW	$ 2.2037	$ 1.7658
General Service 50 to 4,999 kW – Interval Metered	kW	$ 2.4621	$ 1.9681
Unmetered Scattered Load	kWh	$ 0.0053	$ 0.0044
Sentinel Lighting	kW	$ 1.6704	$ 1.3936
Street Lighting	kW	$ 1.6620	$ 1.3652

3.0 RETAIL SERVICE CHARGES

Retail service charges refer to service provided by a distributor to retailers, or customers related to the supply of competitive electricity as set out in the Retail Settlement Code (RSC).

The current retail service rates and charges were established on a generic basis.

RSL maintains the appropriate Retail Service Costs Variance Accounts (RCVA) to record the difference between charges rendered to customers and retailers, and the direct incremental costs for the provision of these services.

RSL does not propose any changes to the existing rates.

4.0 WHOLESALE MARKET SERVICE CHARGES

The Wholesale Market Service Rate is designed to allow distributors to recover costs charged by the Independent Electricity System Operator ("IESO") for the operation of the IESO administered markets and the operation of the IESO-controlled grid. The Wholesale Market Service Rate is an energy based rate (per kWh). This rate only applies to those customers of a distributor who are not wholesale market participants.

The Board has determined that this rate should be consistent across LDCs and, as such, changes to this rate would normally be made on a generic basis.

In decision EB-2011-0405, the Board made the following statement on 2012 rates:

"Ontario Regulation 442/01 (Rural or Remote Electricity Rate Protection) (made under the Ontario Energy Board Act, 1998) requires the Ontario Energy Board (the "Board") to calculate the amount to be charged by the Independent Electricity System Operator ("IESO") with respect to Rural or Remote Electricity Rate Protection ("RRRP") for each kilowatt-hour of electricity that is withdrawn from the IESO-controlled grid.

The Board has determined that effective January 1, 2012, the RRRP charge to be collected by the IESO shall remain at the current level of 0.13 cents per kilowatt-hour.

The Board has further determined that effective May 1, 2012, the IESO's RRRP charge to be collected by the IESO shall be 0.11cents per kilowatt-hour."

RSL has included the revised RRRP rate of 0.11 cents per kwh in this rate application.

RSL is aware that the proposed Wholesale Market Service Charges should be subject to any modifications as a result of any OEB decisions on rate, to be effective on or after January 1, 2012.

5.0 SPECIFIC SERVICE CHARGES

RSL is not requesting any new specific service charges or a change to the level of any existing charge.

6.0 LOW VOLTAGE CHARGES

RSL is an embedded distributor with Hydro One and is subject to Low Voltage charges. RSL has forecasted the total Low Voltage charges for 2012 to be $181,008.

RSL allocated the low voltage costs by customer class based on the similar allocation of the retail transmission connection rates to develop percentage of allocation of the total Low Voltage charges for the customer classes.

Table 8.10

Low voltage Allocation $ by Customer Class

Customer Class	Retail Transmission Connection Rate ($)		Basis for Allocation ($)	Allocation Percentages	Low Voltage Allocated $
	per KWh	per kW			
Residential	0.0048		228,673	41.22%	74,619.97
GS < 50 kW	0.0044		94,661	17.07%	30,889.47
GS 50 - 4,999 kW		1.7658	223,644	40.32%	72,978.84
Sentinel Lights		1.3936	419	0.08%	136.88
Street Lighting		1.3652	5,246	0.95%	1,711.89
USL	0.0044		2,055	0.37%	670.55
TOTALS			**554,698**	**100%**	**181,008**

RSL then designed the rates based on the allocation percentages and revenue projection by each class as set out in the table below.

Table 8.11

Low Voltage Service Charges

Customer Class	LV Adj. Allocated	Calculated kWh	Calculated kW	Volumetric Rate Type	LV/ Adj. Rates/kWh	LV Adj. Rates/ kW
Residential	$74,620	44,584,446	0	kWh	0.0017	
GS < 50 kW	$30,889	19,806,495	0	kWh	0.0016	
GS 50 - 4,999 kW	$72,979		126,652	kW		0.5762
Sentinel Lights	$137		301	kW		0.4547
Street Lighting	$1,712		3,843	kW		0.4455
USL	$671	429,961	0	kWh	0.0016	
TOTALS	**$181,008**	**64,820,902**	**130,796**			

7.0 DETERMINATION OF LOSS ADJUSTMENT FACTORS

RSL is an embedded distributor with Hydro One as the host distributor.

Supply Facility Loss Factor:

The supply facility loss factor (the "SFLF") calculation is shown in Table 8.12 and represents the losses on supply to RSL. The SFLF is calculated on the measured quantities between the transformer stations and the wholesale meter points. The SFLF is used in the calculations of RSL's total loss factor.

Table 8.12

Supply Facilities Loss Factor

		2005	2006	2007	2008	2009	2010
Wholesale Purchased kWh (with Losses)		135,663,190	126,085,570	125,561,560	121,334,640	118,414,830	116,592,701
"Wholesale" kWh (IESO) **Qty at the Meter**		131,202,311	121,939,623	121,432,843	117,344,913	114,521,112	112,758,898
Supply Facility Loss Factor		**1.034**	**1.034**	**1.034**	**1.034**	**1.034**	**1.034**

Total & Distribution Loss Factor:

RSL has calculated the total and distribution loss factor based on the average wholesale and retail kWh for six year period, and then calculated it again for a five year period. The loss factor for the six year period, as shown below in table 8.13 is 1.0833%.

2007 appears to be an anomaly because of the high distribution loss factor – 1.5% greater than any other year in our history. The distribution loss factor based on the average wholesale and retail kWh for the years 2005, 2006, 2008, 2009, and 2010 is 1.0797% as shown in Table 8.13.

Table 8.13

Total & Distribution Loss Factor Calculations

		2005	2006	2007	2008	2009	2010	6 Year total
"Wholesale" kWh (IESO) **Qty at the Meter**		131,202,311	121,939,623	121,432,843	117,344,913	114,521,112	112,758,898	
Net "Wholesale" kWh (A)-(B)		131,202,311	121,939,623	121,432,843	117,344,913	114,521,112	112,758,898	719,199,701
Retail kWh (Distributor) **Qty at the Meter**		126,336,267	116,814,435	113,998,664	111,785,106	109,680,577	107,839,547	686,454,596
		-	-	-	-	-	-	
Net "Retail" kWh (D)-(E)		126,336,267	116,814,435	113,998,664	111,785,106	109,680,577	107,839,547	
								6 Yr Average
Distribution Loss Factor [(C)/(F)]		1.0385	1.0439	1.0652	1.0497	1.0441	1.0456	1.0477
Supply Facility Loss Factor		1.03400	1.03400	1.03400	1.03400	1.03400	1.03400	1.0340
Total Utility Loss Adjustment Factor	LAF							
		average of 2005-2010 years						
Supply Facility Loss Factor	1.0340							
Distribution Loss Factor	1.0442	**5 year average excluding 2007**						
Total Loss Factor						Total Loss Factor		
Secondary Metered Customer						Secondary Metered Customer		
Total Loss Factor - Secondary Metered Customer < 5,000kW	1.0797				Total Loss Factor - Secondary Metered Customer < 5,000kW			1.0833
Total Loss Factor - Secondary Metered Customer > 5,000kW	n/a							
Primary Metered Customer						Primary Metered Customer		
Total Loss Factor - Primary Metered Customer < 5,000kW	1.0689				Total Loss Factor - Primary Metered Customer < 5,000kW			1.0725
Total Loss Factor - Primary Metered Customer > 5,000kW	n/a							

Materiality Analysis on Distribution Losses:

RSL's total loss factor adjustment factor applied for is 1.0797%. This is the five year average for 2005 to 2010, excluding 2007 which was not a typical loss factor for RSL.

RSL excluded 2007 from our requested rate because it is not representative of our normal results. Our review of 2007 was not able to locate customer under billings or any other issues that might have caused the anomaly.

2008 and future years are back to historical levels. It was felt to be fairer and more accurate, if we excluded the anomaly.

RSL Distribution Loss factor for all years used to determine the applied for loss factor are under the 5.0%, pursuant to the filing guidelines.

8.0 RATE SCHEDULES

Other Electricity Charges:

RSL proposes to maintain rates for Wholesale Market Service, Rural Rate Protection Charge, and Standard Supply Service – Administrative Charge at those currently approved by the OEB. Both the Network Service and Line and Transformation Connection rates were revised in the 2011 IRM rate setting process to reflect the changes in the Uniform Transmission Rates.

RSL has completed the Board RTSR model and has included the results in the customer class bill impacts. RSL understands that the RTSR values may change, should revised rates be approved by the Board for Hydro One wholesale line transformation and connection charges, during the process of this Application.

Transformer Allowance:

Currently, RSL provides a Transformer Allowance to those customers that own their transformation facilities. RSL proposes to maintain the current approved transformer ownership allowance of $0.60 per kW. The Transformer Allowance is intended to reflect the costs to a distributor of providing step down transformation facilities to the customer's utilization voltage level. Since the distributor provides electricity at utilization voltage, the cost of this transformation is captured in and recovered through the distribution rates. The transformer allowance amount of $37,995 was determined by the projected forecast for those Industrial Customers who own their transformers. Therefore, when a customer provides its own step down transformation from primary to secondary, it should receive a credit of these costs already included in the distribution rates. The transformer allowance is recovered from the Industrial Class only.

Customer classes:

Residential:

This classification applies to an account taking electricity at 750 volts or less where the electricity is used exclusively in a separate metered living accommodation. Customers shall be residing in single-dwelling units that consist of a detached house or one unit of a semi-detached, duplex, triplex or quadruplex house, with a residential zoning. Separately metered dwellings within a town house complex or apartment building also qualify as residential customers.

General Service Less than 50 kW:

This classification applies to a non-residential account taking electricity at 750 volts or less whose average monthly maximum demand is less than, or is forecast to be less than, 50 kW.

General Service 50 to 4,999 kW:

This classification applies to a non-residential account whose average monthly maximum demand used for billing purposes is equal to or greater than, or is forecast to be equal to or greater than, 50 kW but less than 5,000 kW.

Street Lighting:

This classification applies to an account for roadway lighting with a Municipality, Regional Municipality, Ministry of Transportation and private roadway lighting, controlled by photo cells. The consumption for these customers will be based on the calculated connected load times the required lighting times established in the approved OEB street lighting load shape template.

Sentinel Lighting:

This classification refers to accounts that are an unmetered lighting load supplied to a sentinel light. Further servicing details are available in the distributor's Conditions of Service.

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 unmetered. Such 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

Proposed Distribution Rates:

The following Table 8.15 sets out RSL's proposed 2012 electricity distribution rates based on the foregoing calculations, including recovery of transformer allowance, low voltage charges, and a regulatory asset rate rider.

Table 8.15

Proposed 2012 Electricity Distribution Rates

RATES SCHEDULE (Part 1)

Schedule of Distribution Rates and Charges

Effective May 1, 2012

Customer Class	Item Description	Unit	Rate ($)
Residential			
	Monthly Service Charge	per month	13.10
	Distribution Volumetric Rate	per kWh	0.0149
	Low Voltage Rider	per kWh	0.0017
	LRAM Rate Rider	per kWh	0.0005
	Smart Meter Rate Adder	per month	0.8500
	Deferral and Variance Account Rider	per kWh	(0.0006)
GS < 50 kW			
	Monthly Service Charge	per month	31.43
	Distribution Volumetric Rate	per kWh	0.0096
	Low Voltage Rider	per kWh	0.0016
	LRAM Rate Rider	per kWh	0.0004
	Smart Meter Rate Rider	per month	1.5300
	Deferral and Variance Account Rider	per kWh	(0.0017)
GS 50 - 4,999 kW			
	Monthly Service Charge	per month	379.29
	Distribution Volumetric Rate	per kW	1.5776
	Low Voltage Rider	per kW	0.5762
	LRAM Rate Rider	per kWh	0.0203
	Smart Meter Rate Rider	per month	0.0000
	Deferral and Variance Account Rider	per kW	(0.6893)
Sentinel Lights			
	Monthly Service Charge	per month	1.60
	Distribution Volumetric Rate	per kW	11.7143
	Low Voltage Rider	per kW	0.4547
	LRAM Rate Rider	per kW	0.0000
	Deferral and Variance Account Rider	per kW	0.9301
Street Lighting			
	Monthly Service Charge	per month	2.96
	Distribution Volumetric Rate	per kW	11.2852
	Low Voltage Rider	per kW	0.4455
	LRAM Rate Rider	per kW	0.0000
	Deferral and Variance Account Rider	per kW	(0.8202)
USL			
	Monthly Service Charge	per month	9.57
	Distribution Volumetric Rate	per kWh	0.0439
	Low Voltage Rider	per kWh	0.0016
	LRAM Rate Rider	per kWh	0.0000
	Deferral and Variance Account Rider	per kWh	0.0000

Reconciliation of Rate Class Revenue:

Table 8.16 shows the 2012 Test year Distribution Revenue Reconciliation.

Table 8.16

2012 Test Year Distribution Revenue Reconciliation

Rate Class	Number of Customers/Connections			Test Year Consumption		Proposed Rates			Revenues at Proposed Rates	Service Revenue Requirement	Transformer Allowance Credit	Total	Difference
	Start of Test Year	End of Test Year	Average	kWh	kW	Monthly Service Charge	Volumetric						
							kWh	kW					
Residential	5,011	5,021	5,016	44,584,446		$ 13.10	$ 0.0149		$ 1,452,823	$ 1,453,328		$ 1,453,328	$ 504
GS < 50 kW	770	770	770	19,768,209		$ 31.43	$ 0.0096		$ 480,188	$ 479,683		$ 479,683	-$ 505
GS > 50 to 4,999 kW	66	66	66		126,652	$ 379.29		$ 1.5776	$ 500,203	$ 460,657	$ 37,745	$ 498,402	-$ 1,802
Large Use			-						$ -			$ -	$ -
Streetlighting	1,707	1,711	1,709		3,843	$ 2.96		$ 11.2852	$ 104,011	$ 104,007		$ 104,007	-$ 4
Sentinel Lighting	75	75	75		301	$ 1.60		$ 11.7143	$ 4,970	$ 4,967		$ 4,967	-$ 3
Unmetered Scattered Load	58	58	58	429,961		$ 9.57	$ 0.0439		$ 25,535	$ 25,487		$ 25,487	-$ 48
Standby Power			-						$ -			$ -	$ -
Embedded Distributor			-						$ -			$ -	$ -
etc.			-						$ -			$ -	$ -
			-						$ -			$ -	$ -
			-						$ -			$ -	$ -
			-						$ -			$ -	$ -
Total									$ 2,567,731	$ 2,528,129	$ 37,745	$ 2,565,874	-$ 1,858

Rideau St. Lawrence Distribution Inc.
TARIFF OF RATES AND CHARGES
Existing Rates - Effective Date May 1, 2011

EB-2010-0113

RESIDENTIAL SERVICE CLASSIFICATION

This classification applies to an account taking electricity at 750 volts or less where the electricity is used exclusively in a separate metered living accommodation. Customers shall be residing in single-dwelling units that consist of a detached house or one unit of a semi-detached, duplex, triplex or quadruplex house, with a residential zoning.

Separately metered dwellings within a town house complex or apartment building also qualify as residential customers. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order 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 or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

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MONTHLY RATES AND CHARGES – Electricity Component

Rate Rider for Global Adjustment Sub-Account Disposition – effective until April 30, 2012 Applicable only for Non-RPP Customers	$/kWh	0.0092

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	10.28
Smart Meter Funding Adder – effective until April 30, 2012	$	2.50
Rate Rider for Recovery of Late Payment Penalty Litigation Costs – effective until April 30, 2012	$	0.18
Distribution Volumetric Rate	$/kWh	0.0117
Low Voltage Service Rate	$/kWh	0.0016
Rate Rider for Deferral/Variance Account Disposition (2011) – effective until April 30, 2012	$/kWh	(0.0034)
Rate Rider for Lost Revenue Adjustment Mechanism (LRAM) Recovery/Shared Savings Mechanism (SSM) Recovery – effective until April 30, 2012	$/kWh	0.0007
Retail Transmission Rate – Network Service Rate	$/kWh	0.0056
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0044

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Rideau St. Lawrence Distribution Inc.
TARIFF OF RATES AND CHARGES
Existing Rates - Effective Date May 1, 2011

EB-2010-0113

GENERAL SERVICE LESS THAN 50 kW SERVICE CLASSIFICATION

This classification applies to a non-residential account taking electricity at 750 volts or less whose average monthly maximum demand is less than, or is forecast to be less than, 50 kW. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order 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 or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

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MONTHLY RATES AND CHARGES – Electricity Component

Rate Rider for Global Adjustment Sub-Account Disposition – effective until April 30, 2012 Applicable only for Non-RPP Customers	$/kWh	0.0092

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	24.34
Smart Meter Funding Adder – effective until April 30, 2012	$	2.50
Rate Rider for Recovery of Late Payment Penalty Litigation Costs – effective until April 30, 2012	$	0.37
Distribution Volumetric Rate	$/kWh	0.0074
Low Voltage Service Rate	$/kWh	0.0015
Rate Rider for Deferral/Variance Account Disposition (2011) – effective until April 30, 2012	$/kWh	(0.0034)
Rate Rider for Lost Revenue Adjustment Mechanism (LRAM) Recovery/Shared Savings Mechanism (SSM) Recovery – effective until April 30, 2012	$/kWh	0.0002
Retail Transmission Rate – Network Service Rate	$/kWh	0.0051
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0041

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Rideau St. Lawrence Distribution Inc.
TARIFF OF RATES AND CHARGES
Existing Rates - Effective Date May 1, 2011

EB-2010-0113

GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION

This classification applies to a non-residential account whose average monthly maximum demand used for billing purposes is equal to or greater than, or is forecast to be equal to or greater than, 50 kW but less than 5,000 kW.

Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order 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 or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy Conservation and Renewable Energy Program, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES – Electricity Component

Rate Rider for Global Adjustment Sub-Account Disposition – effective until April 30, 2012 Applicable only for Non-RPP Customers	$/kWh	0.0092

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	281.39
Smart Meter Funding Adder – effective until April 30, 2012	$	2.50
Rate Rider for Recovery of Late Payment Penalty Litigation Costs – effective until April 30, 2012	$	4.15
Distribution Volumetric Rate	$/kW	1.2473
Low Voltage Service Rate	$/kW	0.6110
Rate Rider for Deferral/Variance Account Disposition (2011) – effective until April 30, 2012	$/kW	(1.1172)
Rate Rider for Lost Revenue Adjustment Mechanism (LRAM) Recovery/Shared Savings Mechanism (SSM) Recovery – effective until April 30, 2012	$/kW	0.1388
Retail Transmission Rate – Network Service Rate	$/kW	2.1207
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.6356
Retail Transmission Rate – Network Service Rate – Interval Metered	$/kW	2.3694
Retail Transmission Rate – Line and Transformation Connection Service Rate – Interval Metered	$/kW	1.8230

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Rideau St. Lawrence Distribution Inc.
TARIFF OF RATES AND CHARGES
Existing Rates - Effective Date May 1, 2011

EB-2010-0113

UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION

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 unmetered. Such 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. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order 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 or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy Conservation and Renewable Energy Program, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES – Electricity Component

Rate Rider for Global Adjustment Sub-Account Disposition – effective until April 30, 2012 Applicable only for Non-RPP Customers	$/kWh	0.0092

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge (per customer)	$	7.41
Rate Rider for Recovery of Late Payment Penalty Litigation Costs – effective until April 30, 2012	$	0.26
Distribution Volumetric Rate	$/kWh	0.0340
Low Voltage Service Rate	$/kWh	0.0015
Rate Rider for Deferral/Variance Account Disposition (2011) – effective until April 30, 2012	$/kWh	(0.0034)
Retail Transmission Rate – Network Service Rate	$/kWh	0.0051
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0041

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Rideau St. Lawrence Distribution Inc.
TARIFF OF RATES AND CHARGES
Existing Rates - Effective Date May 1, 2011

EB-2010-0113

SENTINEL LIGHTING SERVICE CLASSIFICATION

This classification refers to accounts that are an unmetered lighting load supplied to a sentinel light. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order 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 or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

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It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy Conservation and Renewable Energy Program, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES – Electricity Component

Rate Rider for Global Adjustment Sub-Account Disposition – effective until April 30, 2012 Applicable only for Non-RPP Customers	$/kWh	0.0092

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge (per connection)	$	1.24
Rate Rider for Recovery of Late Payment Penalty Litigation Costs – effective until April 30, 2012	$	0.04
Distribution Volumetric Rate	$/kW	9.0716
Low Voltage Service Rate	$/kW	0.4720
Rate Rider for Deferral/Variance Account Disposition (2011) – effective until April 30, 2012	$/kW	(3.3648)
Retail Transmission Rate – Network Service Rate	$/kW	1.6075
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.2908

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Rideau St. Lawrence Distribution Inc.
TARIFF OF RATES AND CHARGES
Existing Rates - Effective Date May 1, 2011

EB-2010-0113

STREET LIGHTING SERVICE CLASSIFICATION

This classification applies to an account for roadway lighting with a Municipality, Regional Municipality, Ministry of Transportation and private roadway lighting, controlled by photo cells. The consumption for these customers will be based on the calculated connected load times the required lighting times established in the approved OEB street lighting load shape template. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order 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 or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

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MONTHLY RATES AND CHARGES – Electricity Component

Rate Rider for Global Adjustment Sub-Account Disposition – effective until April 30, 2012 Applicable only for Non-RPP Customers	$/kWh	0.0092

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge (per connection)	$	2.29
Rate Rider for Recovery of Late Payment Penalty Litigation Costs – effective until April 30, 2012	$	0.04
Distribution Volumetric Rate	$/kW	8.7393
Low Voltage Service Rate	$/kW	0.4662
Rate Rider for Deferral/Variance Account Disposition (2011) – effective until April 30, 2012	$/kW	(1.2645)
Retail Transmission Rate – Network Service Rate	$/kW	1.5994
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.2645

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Rideau St. Lawrence Distribution Inc.
TARIFF OF RATES AND CHARGES
Existing Rates - Effective Date May 1, 2011

EB-2010-0113

microFIT GENERATOR SERVICE CLASSIFICATION

This classification applies to an electricity generation facility contracted under the Ontario Power Authority's microFIT program and connected to the distributor's distribution system. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order 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 or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

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MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	5.25

ALLOWANCES

Transformer Allowance for Ownership - per kW of billing demand/month	$/kW	(0.60)
Primary Metering Allowance for transformer losses – applied to measured demand and energy	%	(1.00)

Rideau St. Lawrence Distribution Inc.
TARIFF OF RATES AND CHARGES
Existing Rates - Effective Date May 1, 2011

EB-2010-0113

SPECIFIC SERVICE CHARGES

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No 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 or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy Conservation and Renewable Energy Program, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

Customer Administration		
Arrears certificate	$	15.00
Statement of account	$	15.00
Pulling post-dated cheques	$	15.00
Duplicate invoices for previous billing	$	15.00
Request for other billing information	$	15.00
Easement letter	$	15.00
Income tax letter	$	15.00
Notification charge	$	15.00
Account history	$	15.00
Credit reference/credit check (plus credit agency costs)	$	15.00
Returned cheque charge (plus bank charges)	$	15.00
Charge to certify cheque	$	15.00
Legal letter Charge	$	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	30.00
Meter dispute charge plus Measurement Canada fees (if meter found correct)	$	30.00
Special meter reads	$	30.00
Non-Payment of Account		
Late Payment - per month	%	1.50
Late Payment - per annum	%	19.56
Collection of account charge – no disconnection	$	30.00
Collection of account charge – no disconnection – after regular hours	$	165.00
Disconnect/Reconnect at meter - during regular hours	$	65.00
Disconnect/Reconnect at meter - after regular hours	$	185.00
Disconnect/Reconnect at pole - during regular hours	$	185.00
Disconnect/Reconnect at pole - after regular hours	$	415.00
Service call – customer owned equipment	$	30.00
Service call – after regular hours	$	165.00
Install/Remove load control device – during regular hours	$	65.00
Install/Remove load control device – after regular hours	$	185.00
Temporary service install and remove – overhead – no transformer	$	500.00
Temporary service install and remove – underground – no transformer	$	300.00
Temporary service install and remove – overhead – with transformer	$	1,000.00
Specific Charge for Access to the Power Poles – per pole/year	$	22.35

Rideau St. Lawrence Distribution Inc.
TARIFF OF RATES AND CHARGES
Existing Rates - Effective Date May 1, 2011

EB-2010-0113

RETAIL SERVICE CHARGES (if applicable)

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

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Retail Service Charges refer to services provided by a distributor to retailers or customers related to the supply of competitive electricity

One-time charge, per retailer, to establish the service agreement between the distributor and the retailer	$	100.00
Monthly Fixed Charge, per retailer	$	20.00
Monthly Variable Charge, per customer, per retailer	$/cust.	0.50
Distributor-consolidated billing charge, per customer, per retailer	$/cust.	0.30
Retailer-consolidated billing credit, per customer, per retailer	$/cust.	(0.30)
Service Transaction Requests (STR)		
Request fee, per request, applied to the requesting party	$	0.25
Processing fee, per request, applied to the requesting party	$	0.50
Request for customer information as outlined in Section 10.6.3 and Chapter 11 of the Retail Settlement Code directly to retailers and customers, if not delivered electronically through the Electronic Business Transaction (EBT) system, applied to the requesting party		
Up to twice a year no charge		
More than twice a year, per request (plus incremental delivery costs)	$	2.00

LOSS FACTORS

If the distributor is not capable of prorating changed loss factors jointly with distribution rates, the revised loss factors will be implemented upon the first subsequent billing for each billing cycle.

Total Loss Factor – Secondary Metered Customer < 5,000 kW	1.0764
Total Loss Factor – Secondary Metered Customer > 5,000 kW	N/A
Total Loss Factor – Primary Metered Customer < 5,000 kW	1.0657
Total Loss Factor – Primary Metered Customer > 5,000 kW	N/A

Rideau St. Lawrence Distribution Inc.
TARIFF OF RATES AND CHARGES
Proposed Rates - Effective Date May 1, 2012

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2011-0274

RESIDENTIAL SERVICE CLASSIFICATION

This classification applies to an account taking electricity at 750 volts or less where the electricity is used exclusively in a separate metered living accommodation. Customers shall be residing in single-dwelling units that consist of a detached house or one unit of a semi-detached, duplex, triplex or quadruplex house, with a residential zoning.

Separately metered dwellings within a town house complex or apartment building also qualify as residential customers. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order 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 or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

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MONTHLY RATES AND CHARGES – Electricity Component

Rate Rider for Global Adjustment Sub-Account Disposition – effective until April 30, 2013 Applicable only for Non-RPP Customers	$/kWh	(0.0005)

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	13.10
Smart Meter Disposition Rider – effective until April 30, 2013	$	0.85
Stranded Assets Rate Rider – effective until April 30, 2013	$	2.04
Distribution Volumetric Rate	$/kWh	0.0149
Low Voltage Service Rate	$/kWh	0.0017
Rate Rider for Deferral/Variance Account Disposition – effective until April 30, 2013	$/kWh	(0.0006)
Rate Rider for Lost Revenue Adjustment Mechanism (LRAM) Recovery – effective until April 30, 2013	$/kWh	0.0005
Retail Transmission Rate – Network Service Rate	$/kWh	0.0058
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0048

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Rideau St. Lawrence Distribution Inc.
TARIFF OF RATES AND CHARGES

Proposed Rates - Effective Date May 1, 2012

This schedule supersedes and replaces all previously
approved schedules of Rates, Charges and Loss Factors

EB-2011-0274

GENERAL SERVICE LESS THAN 50 kW SERVICE CLASSIFICATION

This classification applies to a non-residential account taking electricity at 750 volts or less whose average monthly maximum demand is less than, or is forecast to be less than, 50 kW. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order 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 or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy Conservation and Renewable Energy Program, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES – Electricity Component

Rate Rider for Global Adjustment Sub-Account Disposition – effective until April 30, 2013 Applicable only for Non-RPP Customers	$/kWh	(0.0004)

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	31.43
Smart Meter Disposition Rider – effective until April 30, 2013	$	1.53
Stranded Assets Rate Rider – effective until April 30, 2013	$	6.24
Distribution Volumetric Rate	$/kWh	0.0096
Low Voltage Service Rate	$/kWh	0.0016
Rate Rider for Deferral/Variance Account Disposition– effective until April 30, 2013	$/kWh	(0.0017)
Rate Rider for Lost Revenue Adjustment Mechanism (LRAM) Recovery – effective until April 30, 2013	$/kWh	0.0004
Retail Transmission Rate – Network Service Rate	$/kWh	0.0053
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0044

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Rideau St. Lawrence Distribution Inc.
TARIFF OF RATES AND CHARGES
Proposed Rates - Effective Date May 1, 2012

This schedule supersedes and replaces all previously
approved schedules of Rates, Charges and Loss Factors

EB-2011-0274

GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION

This classification applies to a non-residential account whose average monthly maximum demand used for billing purposes is equal to or greater than, or is forecast to be equal to or greater than, 50 kW but less than 5,000 kW.

Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order 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 or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy Conservation and Renewable Energy Program, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES – Electricity Component

Rate Rider for Global Adjustment Sub-Account Disposition – effective until April 30, 2013 Applicable only for Non-RPP Customers	$/kWh	(0.9469)

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	379.29
Smart Meter Funding Adder – effective until April 30, 2013	$	0.0000
Stranded Assets Rate Rider – effective until April 30, 2013	$	0.0000
Distribution Volumetric Rate	$/kW	1.5776
Low Voltage Service Rate	$/kW	0.5762
Rate Rider for Deferral/Variance Account Disposition– effective until April 30, 2013	$/kW	(0.6893)
Rate Rider for Lost Revenue Adjustment Mechanism (LRAM) Recovery – effective until April 30, 2013	$/kW	0.0203
Retail Transmission Rate – Network Service Rate	$/kW	2.2037
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.7658
Retail Transmission Rate – Network Service Rate – Interval Metered	$/kW	2.4621
Retail Transmission Rate – Line and Transformation Connection Service Rate – Interval Metered	$/kW	1.9681

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Rideau St. Lawrence Distribution Inc.
TARIFF OF RATES AND CHARGES
Proposed Rates - Effective Date May 1, 2012

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UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION

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 unmetered. Such 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. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order 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 or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy Conservation and Renewable Energy Program, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES – Electricity Component

Rate Rider for Global Adjustment Sub-Account Disposition – effective until April 30, 2013 Applicable only for Non-RPP Customers	$/kWh	0.0000

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge (per customer)	$	9.57
Distribution Volumetric Rate	$/kWh	0.0439
Low Voltage Service Rate	$/kWh	0.0016
Rate Rider for Deferral/Variance Account Disposition – effective until April 30, 2013	$/kWh	(0.0002)
Rate Rider for Lost Revenue Adjustment Mechanism (LRAM) Recovery – effective until April 30, 2013	$/kWh	0.0000
Retail Transmission Rate – Network Service Rate	$/kWh	0.0053
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0044

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Rideau St. Lawrence Distribution Inc.
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SENTINEL LIGHTING SERVICE CLASSIFICATION

This classification refers to accounts that are an unmetered lighting load supplied to a sentinel light. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

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Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy Conservation and Renewable Energy Program, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES – Electricity Component

Rate Rider for Global Adjustment Sub-Account Disposition – effective until April 30, 2013 Applicable only for Non-RPP Customers	$/kWh	0.0000

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge (per connection)	$	1.60
Stranded Assets Rate Rider – effective until April 30, 2013	$	0.0000
Distribution Volumetric Rate	$/kW	11.7143
Low Voltage Service Rate	$/kW	0.4547
Rate Rider for Deferral/Variance Account Disposition – effective until April 30, 2013	$/kW	0.9301
Retail Transmission Rate – Network Service Rate	$/kW	1.6704
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.3936

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Rideau St. Lawrence Distribution Inc.
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Proposed Rates - Effective Date May 1, 2012

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STREET LIGHTING SERVICE CLASSIFICATION

This classification applies to an account for roadway lighting with a Municipality, Regional Municipality, Ministry of Transportation and private roadway lighting, controlled by photo cells. The consumption for these customers will be based on the calculated connected load times the required lighting times established in the approved OEB street lighting load shape template. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order 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 or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

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It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy Conservation and Renewable Energy Program, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES – Electricity Component

Rate Rider for Global Adjustment Sub-Account Disposition – effective until April 30, 2013 Applicable only for Non-RPP Customers	$/kWh	(1.4035)

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge (per connection)	$	2.96
Distribution Volumetric Rate	$/kW	11.2852
Low Voltage Service Rate	$/kW	0.4455
Rate Rider for Deferral/Variance Account Disposition – effective until April 30, 2013	$/kW	(0.8202)
Retail Transmission Rate – Network Service Rate	$/kW	1.6620
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.3652

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Rideau St. Lawrence Distribution Inc.
TARIFF OF RATES AND CHARGES
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microFIT GENERATOR SERVICE CLASSIFICATION

This classification applies to an electricity generation facility contracted under the Ontario Power Authority's microFIT program and connected to the distributor's distribution system. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order 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 or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

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MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	5.25

ALLOWANCES

Transformer Allowance for Ownership - per kW of billing demand/month	$/kW	(0.60)
Primary Metering Allowance for transformer losses – applied to measured demand and energy	%	(1.00)

Rideau St. Lawrence Distribution Inc.
TARIFF OF RATES AND CHARGES
Proposed Rates - Effective Date May 1, 2012

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SPECIFIC SERVICE CHARGES

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No 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 or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy Conservation and Renewable Energy Program, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

Customer Administration		
Arrears certificate	$	15.00
Statement of account	$	15.00
Pulling post-dated cheques	$	15.00
Duplicate invoices for previous billing	$	15.00
Request for other billing information	$	15.00
Easement letter	$	15.00
Income tax letter	$	15.00
Notification charge	$	15.00
Account history	$	15.00
Credit reference/credit check (plus credit agency costs)	$	15.00
Returned cheque charge (plus bank charges)	$	15.00
Charge to certify cheque	$	15.00
Legal letter Charge	$	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	30.00
Meter dispute charge plus Measurement Canada fees (if meter found correct)	$	30.00
Special meter reads	$	30.00
Non-Payment of Account		
Late Payment - per month	%	1.50
Late Payment - per annum	%	19.56
Collection of account charge – no disconnection	$	30.00
Collection of account charge – no disconnection – after regular hours	$	165.00
Disconnect/Reconnect at meter - during regular hours	$	65.00
Disconnect/Reconnect at meter - after regular hours	$	185.00
Disconnect/Reconnect at pole - during regular hours	$	185.00
Disconnect/Reconnect at pole - after regular hours	$	415.00
Service call – customer owned equipment	$	30.00
Service call – after regular hours	$	165.00
Install/Remove load control device – during regular hours	$	65.00
Install/Remove load control device – after regular hours	$	185.00
Temporary service install and remove – overhead – no transformer	$	500.00
Temporary service install and remove – underground – no transformer	$	300.00
Temporary service install and remove – overhead – with transformer	$	1,000.00
Specific Charge for Access to the Power Poles – per pole/year	$	22.35

Rideau St. Lawrence Distribution Inc.
TARIFF OF RATES AND CHARGES
Proposed Rates - Effective Date May 1, 2012

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2011-0274

RETAIL SERVICE CHARGES (if applicable)

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order 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 or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy Conservation and Renewable Energy Program, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

Retail Service Charges refer to services provided by a distributor to retailers or customers related to the supply of competitive electricity

One-time charge, per retailer, to establish the service agreement between the distributor and the retailer	$	100.00
Monthly Fixed Charge, per retailer	$	20.00
Monthly Variable Charge, per customer, per retailer	$/cust.	0.50
Distributor-consolidated billing charge, per customer, per retailer	$/cust.	0.30
Retailer-consolidated billing credit, per customer, per retailer	$/cust.	(0.30)
Service Transaction Requests (STR)		
Request fee, per request, applied to the requesting party	$	0.25
Processing fee, per request, applied to the requesting party	$	0.50
Request for customer information as outlined in Section 10.6.3 and Chapter 11 of the Retail Settlement Code directly to retailers and customers, if not delivered electronically through the Electronic Business Transaction (EBT) system, applied to the requesting party		
Up to twice a year no charge		
More than twice a year, per request (plus incremental delivery costs)	$	2.00

LOSS FACTORS

If the distributor is not capable of prorating changed loss factors jointly with distribution rates, the revised loss factors will be implemented upon the first subsequent billing for each billing cycle.

Total Loss Factor – Secondary Metered Customer < 5,000 kW	1.0797
Total Loss Factor – Secondary Metered Customer > 5,000 kW	N/A
Total Loss Factor – Primary Metered Customer < 5,000 kW	1.0689
Total Loss Factor – Primary Metered Customer > 5,000 kW	N/A

9.0 BILL IMPACT INFORMATION

The Tables below present the results of the assessment of customer total bill impacts by customer rate class. Representative customers have been included for each customer class to display the bill impact for that class.

Impacts are derived using the current distribution rates and the proposed 2012 rates.

The total bill impacts are calculated for each rate class at various levels of consumption. The rate impacts are assessed on the basis of moving to the proposed distribution rates.

Table 8.16

BILL IMPACT INFORMATION BY CUSTOMER CLASS

RESIDENTIAL

		2011 BILL			2012 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Consumption	Monthly Service Charge			10.28			13.10	2.82	27.43%	10.40%
800 kWh	Distribution (kWh)	800	0.0117	9.36	800	0.0149	11.92	2.56	27.35%	9.46%
	Low Voltage Rider (kWh)	800	0.0016	1.28	800	0.0017	1.34	0.06	4.60%	1.06%
	Smart Meter & LPC Rider - monthly			2.68			0.85	(1.83)	(68.28%)	0.67%
	LRAM Rate Rider (kWh)	800	0.0007	0.56	800	0.0005	0.40	(0.16)	(28.57%)	0.32%
	Stranded Assets/Month			0.00			2.04	2.04	#DIV/0!	1.62%
	Late Payment (kWh)	1		0.00	1	0.0000	0.00	0.00	#DIV/0!	0.00%
	Deferrral & Variance Acct (kWh)	800	(0.0034)	(2.72)	800	(0.0006)	(0.44)	2.28	(83.81%)	(0.35%)
	Distribution Sub-Total			**21.44**			**29.21**	**7.77**	**36.23%**	**23.19%**
	Retail Transmisssion (kWh)	861	0.0100	8.61	864	0.010569	9.13	0.52	6.02%	7.25%
	Delivery Sub-Total			**30.05**			**38.34**	**8.29**	**27.58%**	**30.44%**
	Other Charges (kWh)	861	0.0135	11.63	864	0.0133	11.49	(0.14)	(1.18%)	9.12%
	Cost of Power Commodity (kWh)	600	0.0680	40.80	600	0.0680	40.80	0.00	0.00%	32.39%
	Cost of Power Commodity (kWh)	261	0.0790	20.63	264	0.0790	20.84	0.21	1.02%	16.54%
	SPC (kWh)	861	0.0004	0.32	864		0.00	(0.32)	(100.00%)	0.00%
	Total Bill Before Taxes			**103.43**			**111.46**	**8.36**	**8.08%**	**88.50%**
	HST		13.00%	13.45		13.00%	14.49	1.05	7.77%	11.50%
	Total Bill			**116.87**			**125.95**	**9.40**	**8.05%**	**100.00%**

GENERAL SERVICE < 50 kW

		2011 BILL			2012 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Consumption	Monthly Service Charge			24.34			31.43	7.09	29.13%	10.20%
2,000 kWh	Distribution (kWh)	2,000	0.0074	14.80	2,000	0.0096	19.20	4.40	29.73%	6.23%
	Low Voltage Rider (kWh)	2,000	0.0015	3.00	2,000	0.0016	3.12	0.12	3.97%	1.01%
	Smart Meter & LPC Rider - monthly			2.87			1.53	(1.34)	(46.69%)	0.50%
	LRAM Rate Rider (kWh)	2,000	0.0002	0.40	2,000	0.0004	0.80	0.40	100.00%	0.26%
	Stranded Assets/Month			0.00			6.24	6.24	#DIV/0!	2.03%
	Late Payment (kWh)	1	0.3700	0.37	1	0.0000	0.00	(0.37)	(100.00%)	0.00%
	Deferrral & Variance Acct (kWh)	2,000	(0.0034)	(6.80)	2,000	(0.0017)	(3.40)	3.40	(50.06%)	(1.10%)
	Distribution Sub-Total			**38.98**			**58.92**	**19.94**	**51.16%**	**19.13%**
	Retail Transmisssion (kWh)	2,153	0.0092	19.81	2,159	0.009726	21.00	1.20	6.04%	6.82%
	Delivery Sub-Total			**58.79**			**79.93**	**21.14**	**35.96%**	**25.94%**
	Other Charges (kWh)	2,153	0.0135	29.06	2,159	0.0133	28.72	(0.34)	(1.18%)	9.32%
	Cost of Power Commodity (kWh)	600	0.0680	40.80	600	0.0680	40.80	0.00	0.00%	13.24%
	Cost of Power Commodity (kWh)	1,553	0.0790	122.67	1,559	0.0790	123.20	0.52	0.43%	39.99%
	SPC (kWh)	2,153	0.0000	0.00	2,153	0.0000	0.00	0.00	#DIV/0!	0.00%
	Total Bill Before Taxes			**251.32**			**272.64**	**$21.32**	**8.48%**	**88.50%**
	HST		13.00%	32.67		13.00%	35.44	2.77	8.48%	11.50%
	Total Bill			**283.99**			**308.09**	**$24.09**	**8.48%**	**100.00%**

GENERAL SERVICE > 50 kW

		2011 BILL			2012 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
Consumption	Monthly Service Charge			281.39			379.29	97.90	34.79%	2.03%
166,000 kWh	Distribution (kW)	290	1.2473	361.72	290	1.5776	457.50	95.79	26.48%	2.45%
290 kW	Low Voltage Rider (kW)	290	0.611	177.19	290	0.5762	167.10	(10.09)	(5.69%)	0.89%
	Smart Meter & LPC Rider - monthly			6.65			0.00	(6.65)	(100.00%)	0.00%
	LRAM Rate Rider (kWh)	290		0.00	290	0.0203	5.89	5.89	#DIV/0!	0.03%
	Smart Meter Entity ($/Month)			0.00			0.00	0.00	#DIV/0!	0.00%
	Late Payment (kWh)	166,000	0.0000	0.00	166,000	0.0000	0.00	0.00	#DIV/0!	0.00%
	Deferrral & Variance Acct (kW)	290	(1.1172)	(323.99)	290	(0.6893)	(199.90)	124.09	(38.30%)	(1.07%)
	Distribution Sub-Total			**502.96**			**809.89**	**306.93**	**61.02%**	**4.34%**
	Retail Transmisssion (kW)	290	3.7563	1,089.33	290	3.969517	1,151.16	61.83	5.68%	6.16%
	Delivery Sub-Total			**1,592.29**			**1,961.05**	**368.76**	**23.16%**	**10.50%**
	Other Charges (kWh)	178,682	0.0135	2,412.21	179,233	0.0133	2,383.80	(28.41)	(1.18%)	12.76%
	Cost of Power Commodity (kWh)	178,682	0.0680	12,150.40	179,233	0.0680	12,187.86	37.45	0.31%	65.24%
	SPC (kWh)	178,682	0.0000	0.00	178,682	0.0000	0.00	0.00	#DIV/0!	0.00%
	Total Bill Before Taxes			**16,154.90**			**16,532.70**	**377.80**	**2.34%**	**88.50%**
	HST		13.00%	2,100.14		13.00%	2,149.25	49.11	2.34%	11.50%
	Total Bill			**18,255.04**			**18,681.96**	**426.92**	**2.34%**	**100.00%**

Street Lighting

		2011 BILL			2012 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
Billing Determinants	Monthly Service Charge	684	2.2900	1,566.36	684	2.9571	2,022.66	456.30	29.13%	19.94%
684 Conne	Distribution (kW)	140	8.7393	1,223.50	140	11.2852	1,579.93	356.43	29.13%	15.57%
57,000.00 kWh	Low Voltage Rider (kW)	140	0.4662	65.27	140	0.4455	62.37	(2.90)	(4.44%)	0.61%
140.00 kW	LRAM Rate Rider (kWh)	140		0.00	140	0.0000	0.00	0.00	#DIV/0!	0.00%
	Late Payment per month	684	0.0400	27.36	684	0.0000	0.00	(27.36)	(100.00%)	0.00%
	Deferrral & Variance Acct (kW)	140	(1.2645)	-177.03	140	(0.8202)	(114.82)	62.21	(35.14%)	(1.13%)
	Distribution Sub-Total			**2,705.46**			**3,550.13**	**844.67**	**31.22%**	**35.00%**
	Retail Transmisssion (kW)	140	2.8639	400.95	140	3.02717	423.80	22.86	5.70%	4.18%
	Delivery Sub-Total			**3,106.41**			**3,973.93**	**867.53**	**27.93%**	**39.17%**
	Other Charges (kWh)	61,355	0.0135	828.29	61,544	0.0133	818.53	(9.76)	(1.18%)	8.07%
	Cost of Power Commodity (kWh)	61,355	0.0680	4,172.13	61,544	0.0680	4,184.99	12.86	0.31%	41.25%
	SPC (kWh)	61,355	0.0000	0.00	61,355	0.0000	0.00	0.00	#DIV/0!	0.00%
	Total Bill Before Taxes			**8,106.82**			**8,977.46**	**870.63**	**10.74%**	**88.50%**
	HST		13.00%	1,053.89		13.00%	1,167.07	113.18	10.74%	11.50%
	Total Bill			**9,160.71**			**10,144.52**	**983.82**	**10.74%**	**100.00%**

Sentinel Lighting

Billing Determinants			2011 BILL			2012 BILL			IMPACT		
			Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
		Monthly Service Charge	2	1.2400	2.48	2	1.6012	3.20	0.72	29.13%	8.17%
2	Conne	Distribution (kW)	1	9.0716	5.99	1	11.7143	7.73	1.74	29.13%	19.73%
237	kWh	Low Voltage Rider (kW)	1	0.472	0.31	1	0.4547	0.30	(0.01)	(3.66%)	0.77%
0.7	kW	LRAM Rate Rider (kWh)	1		0.00	1	0.0000	0.00	0.00	#DIV/0!	0.00%
		Late Payment per month	2	0.0400	0.08	2	0.0000	0.00	(0.08)	(100.00%)	0.00%
		Deferrral & Variance Acct (kW)	1	(3.3648)	-2.22	1	0.9301	0.61	2.83	(127.64%)	1.57%
		Distribution Sub-Total			**6.64**			**11.85**	**5.21**	**78.48%**	**30.24%**
		Retail Transmisssion (kW)	1	2.8983	1.91	1	3.063981	2.02	0.11	5.72%	5.16%
		Delivery Sub-Total			**8.55**			**13.87**	**5.32**	**62.21%**	**35.40%**
		Other Charges (kWh)	255	0.0135	3.44	256	0.0133	3.40	(0.04)	(1.18%)	8.69%
		Cost of Power Commodity (kWh)	255	0.0680	17.35	256	0.0680	17.40	0.05	0.31%	44.41%
		SPC (kWh)	255	0.0000	0.00	255	0.0000	0.00	0.00	#DIV/0!	0.00%
		Total Bill Before Taxes			**29.34**			**34.67**	**5.33**	**18.17%**	**88.50%**
		HST		13.00%	3.81		13.00%	4.51	0.69	18.17%	11.50%
		Total Bill			**33.16**			**39.18**	**6.03**	**18.17%**	**100.00%**

Unmetered Scattered

Consumption 744 kWh

	2011 BILL			2012 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
Monthly Service Charge			7.41			9.57	2.16	29.13%	7.28%
Distribution (kWh)	744	0.0340	25.30	744	0.0439	32.66	7.37	29.12%	24.84%
Low Voltage Rider (kWh)	744	0.0015	1.12	744	0.0016	1.16	0.04	3.97%	0.88%
LRAM Rate Rider (kWh)	744	0.0000	0.00	744	0.0000	0.00	0.00	#DIV/0!	0.00%
Late Payment per month	1	0.2600	0.26	744	0.0000	0.00	(0.26)	(100.00%)	0.00%
Deferrral & Variance Acct (kWh)	744	(0.0034)	(2.53)	744	(0.0002)	(0.15)	2.38	(93.94%)	(0.12%)
Distribution Sub-Total			**31.55**			**43.24**	**11.68**	**37.03%**	**32.88%**
Retail Transmisssion (kWh)	801	0.0092	7.37	803	0.009726	7.81	0.45	6.04%	5.94%
Delivery Sub-Total			**38.92**			**51.05**	**12.13**	**31.17%**	**38.83%**
Other Charges (kWh)	801	0.0135	10.81	803	0.0133	10.68	(0.13)	(1.18%)	8.13%
Cost of Power Commodity (kWh)	801	0.0680	54.46	803	0.0680	54.63	0.17	0.31%	41.54%
SPC (kWh)	801	0.0000	0.00	801	0.0000	0.00	0.00	#DIV/0!	0.00%
Total Bill Before Taxes			**104.19**			**116.36**	**11.73**	**11.25%**	**88.50%**
HST		13.00%	13.54		13.00%	15.13	1.58	11.68%	11.50%
Total Bill			**117.73**			**131.49**	**13.31**	**11.30%**	**100.00%**

10.0 RATE MITIGATION

RSL submits that the bill impacts of its proposed 2012 electricity distribution rates are not so significant as to warrant any further mitigation measures.

Residential, GS<50kW, and GS>50kW bill impacts are all under 9%.

The bill Impacts for Street lights, Sentinel Lights, and Scattered Loads all exceed the 10% materiality factor.

Table 8.17, provides a representative bill impact for each class of RSL customers.

While the percentage increase exceeds the materiality, the dollar increase on representative bills is not significant - $6.03 for Sentinel Lights, and $13.31 for Unmetered Scattered Load.

Street Lighting - 2012 OEB Cost Allocation Model has increased the revenue to cost ratio to 80.60% - well within the Board Target Range of Low 70, High 120. The Bill Impact for Street Lighting is 10.74% as shown below, and in the Bill Impact section.

Table 8.17

Customer Class Bill Impact

Class	Consumption	Current Bill	Proposed Bill	Bill Impact	Bill Impact
		2011 Approved Rates	2012 Proposed Rates	$	%
Residential	800 kWh	$116.87	$125.95	$9.40	8.05%
GS <50kW	2,000 kWh	$283.99	$308.09	$24.09	8.48%
GS >50 kW	290 kW	$18,255.04	$18,681.96	$426.92	2.34%
Street Lighting	140 kW	$9,160.71	$10,144.52	$983.82	10.74%
Sentinel Lights	0.7 kW	$33.16	$39.18	$6.03	18.17%
Scattered Load	744 kWh	$117.73	$131.49	$13.31	11.30%

<u>Exhibit 9</u> <u>Deferral and Variance Accounts</u>

1.0 OVERVIEW

The information contained in this exhibit includes the status and description of RSL's deferral and variance accounts, the proposed disposition of certain account balances, and the rate riders required for recovery or refund of the account balances.

Previous Deferral / Variance Accounts Final Dispositions:

2011 IRM EB-2010-0113:

On April 6, 2011, the Ontario Energy Board's Decision and Order EB-2010-0113, approved disposition of Group 1 account balances as of December 31, 2009, over a one year period, commencing May 1, 2011. While the net total of the Group 1 accounts did not meet the materiality factor as outlined in the EDDVAR report, the RSVA Power, and the RSVA Power Global Adjustment Sub-account when considered on a stand-alone basis, each meet that factor.

Because of the magnitude of the RSVA Power Global Adjustment Sub-account, the Board approved the clearing of all Group 1 December 31, 2009 balances on a final basis as it was in the public interest and could have created intergenerational inequities (allocated to only non RPP customer) if not cleared on a timely basis.

In June of 2011, the amounts shown in Table 9.1 were cleared into account 1595.

Table 9.1

2011 IRM - Group 1 Amounts Approved for Final Disposition

Account Description	Account Number	Principal Amounts A	Interest Amounts B	Total Claim C = A + B
LV Variance Account	1550	45,017	(737)	44,280
RSVA - Wholesale Market Service Charge	1580	37,071	3,268	40,339
RSVA - Retail Transmission Network Charge	1584	75,490	2,203	77,693
RSVA - Retail Transmission Connection Charge	1586	68,229	10,640	78,869
RSVA - Power (Excluding Global Adjustment)	1588	148,150	(15,620)	132,531
RSVA - Power (Global Adjustment Sub-account)	1588	(402,883)	(6,186)	(409,069)
Recovery of Regulatory Asset Balances	1590	(195)	653	458
Balance of Disposition and recovery of Regulatory Balances Account (2008)	1595	0	0	0
Disposition and recovery of Regulatory Balances Account	1595	29,121	5,779	34,900
	Total	0	0	0

2010 IRM EB-2009-0248:

On April 6, 2010 the Ontario Energy Board's Decision and Order EB-2009-0248, approved disposition of Group 1 account balances as of December 31, 2008, over a one year period, commencing May 1, 2010. In implementing this decision, RSL agreed to allocate the Global Adjustment Sub-account rate rider to non-RPP customers.

Table 9.2 below, shows the balances approved on a final basis, and transferred to account 1595 in May of 2010.

Table 9.2

2010 IRM - Group 1 Amounts Approved for Final Disposition

Account Description	Account Number	Principal Amounts A	Interest Amounts B	Total Claim C = A + B
LV Variance Account	1550	(121,410)	(6,034)	(127,444)
RSVA - Wholesale Market Service Charge	1580	244,152	5,203	249,355
RSVA - Retail Transmission Network Charge	1584	102,290	7,071	109,360
RSVA - Retail Transmission Connection Charge	1586	107,116	16,402	123,519
RSVA - Power (Excluding Global Adjustment)	1588	(389,187)	(52,915)	(442,102)
RSVA - Power (Global Adjustment Sub-account)	1588	(246,991)	3,831	(243,160)
Recovery of Regulatory Asset Balances	1590	447,796	(352,672)	95,124
Disposition and recovery of Regulatory Balances Account	1595	(143,766)	379,114	235,348
	Total	0	0	0

2008 COS EB-2007-0762:

On May 6, 2008 the Ontario Energy Board's Decision and Order EB-2007-0762, approved disposition of Deferral and Variance Accounts 1508 and 1550.

The amounts shown below in Table 9.3 were approved to be recovered over a two year period, commencing June 13, 2008.

Table 9.3

2008 Deferral and Variance Approved Disposition

Account Description	Account	Principal	Interest	Total Claim
Other Regulatory Assets	1508	$12,362	$1,414	$13,776
Low voltage Variance	1550	$46,697	$2,850	$49,547
Disposition and recovery	1595	($59,059)	($4,264)	($63,323)

2.0 STATUS OF DEFERRAL AND VARIANCE ACCOUNTS

This Schedule contains descriptions of Deferral and Variance Accounts (“DVAs”) currently used by RSL. The balances as at December 31, 2010, and the requested recovery amounts, are summarized in Table 9.4 – following the descriptions of each account.

The Board prescribed interest rates are used to calculate the carrying charges and the interest is recorded in a sub-account, for all Deferral and Variance Accounts.

Group 1 Accounts:

1550 Low Voltage (LV) Variance Account

This account is used to record the LV amounts charged by the host distributor to an embedded distributor, and the amount billed to customers based on approved LV rates in accordance with the APH.

For 2012 RSL is requesting disposition of the December 31, 2010 audited balance plus the forecast interest through April 30, 2012 for account 1550.

1580 Retail Settlement Variance Account - Wholesale Market Service Charges

This account is used to record the net of the amount charged by the IESO based on the settlement invoice for the operation of the IESO-administered markets and the operation of the IESO-controlled grid, and the amount billed to customers using the OEB-approved Wholesale Market Service Rate.

For 2012 RSL is requesting disposition of the December 31, 2010 audited balance plus the forecast interest through April 30, 2012 for account 1580.

1584 Retail Settlement Variance Account - Retail Transmission Network Charges

This account is used to record the net of the amount charged by the IESO and Hydro One Networks, based on the settlement invoice for transmission network services, and the amount billed to customers using the OEB-approved Transmission Network Charge.

For 2012 RSL is requesting disposition of the December 31, 2010 audited balance plus the forecast interest through April 30, 2012 for account 1584.

1586 Retail Settlement Variance Account - Retail Transmission Connection Charges

This account is used to record the net of the amount charged by the IESO and Hydro One Networks, based on the settlement invoice for transmission connection services, and the amount billed to customers using the OEB-approved Transmission Connection Charge.

For 2012 RSL is requesting disposition of the December 31, 2010 audited balance plus the forecast interest through April 30, 2012 for account 1586.

1588 Retail Settlement Variance Account – Power (excluding Global Adjustments).

This account is used to recover the net difference between the energy amount billed to customers and the energy charge to RSL using the settlement invoice from the Independent Electricity System Operator ("IESO"), net of the Global Adjustment. The variance between the Board-approved and actual line losses is reflected in Account 1588 for the applicable period.

For 2012 RSL is requesting disposition of the December 31, 2010 audited balance plus the forecast interest through April 30, 2012 for account 1588 – Power.

1588 Retail Settlement Variance Account - Power, Sub-account Global Adjustments

This account is used to recover the net difference between the provincial benefit amount billed to customers and the global adjustment charge to RSL using the settlement invoice from the IESO.

For 2012 RSL is requesting disposition of the December 31, 2010 audited balance plus the forecast interest through April 30, 2012 for account 1588 – GA.

1590 Recovery of Regulatory Asset Balances

This account includes the regulatory asset or liability balances authorized by the Board for recovery in rates or payments/credits made to customers.

For 2012 RSL is requesting disposition of the December 31, 2010 audited balance plus the forecast interest through April 30, 2012 for account 1590.

1595 Recovery of Regulatory Asset Balances

This account includes the regulatory asset or liability balances authorized by the Board for recovery in rates or payments/credits made to customers. As part of our conversion to our new Accounting/Financial System, separate sub-accounts have been created for each Board-approved recovery.

Sub-account 2008 for EB-2007-0762: RSL is requesting recovery of the residual balance in this sub-account, as the two year recovery period was completed as of April 30, 2010.

Sub-account 2010 for EB-2009-0248: RSL is not requesting recovery of the residual balance in this sub-account, as the two year recovery period was not completed as of December 31, 2010.

Sub-account 2010 for EB-2010-0113: RSL is not requesting recovery of the residual balance in this sub-account, as the two year recovery period was not completed as of December 31, 2010.

Group 2 Accounts:

1508 Other Regulatory Assets - Sub-account OEB Cost Assessments:

This account was used for calculating the incremental OEB Cost Assessment for the period January 1, 2004 to April 30, 2006 in excess of amounts previously included in rates (1999 OEB costs). In RSL's 2008 Cost of Service Application (EB-2007-0762) Board approval was received for the recovery of RSL's 2006 Audited December 31, 2006 balance, with estimated interest improvement being added until April 30, 2008. The balance in this account is the difference between the estimated and the actual interest improvement charges from January 1, 2007 until April 30, 2008.

For 2012 RSL is requesting disposition of the December 31, 2010 audited balance plus the forecast interest through April 30, 2012 for account 1508 – Sub Account OEB Cost Assessment.

1508 Other Regulatory Assets – Sub-account Incremental Capital Charges

This account is used to record the amount charged by Hydro One Networks Inc., based on the settlement invoice for Incremental Capital Charges.

For 2012 RSL is requesting disposition of the December 31, 2010 audited balance plus the forecast interest through April 30, 2012 for account 1508 Sub Account Incremental Capital.

1508 Other Regulatory Assets – Sub-Account IFRS Transition Costs:

RSL has established account 1508 – sub account IFRS Transition Costs in accordance with the Board Requirements. RSL is not seeking disposition of the December 31, 2010 audited balance in this application. In accordance with the Board's instructions, the balance in this sub-account will be included for review and disposition in a future rate application immediately after the IFRS transition period.

1508 Other Regulatory Assets: Sub Account Late Payment and Litigation Costs (LPP)

This account includes the costs arising from the settlement of the LPP class

action law suit, and sought for recovery from all ratepayers. For 2010 Year End, the LPP was accrued in Account 1521 in error. In 2011 the $18,391.97 cost to RSL for the LPP was transferred to the proper account 1508 – Sub account LPP.

RSL is not requesting recovery of the residual balance in this sub-account, as the recovery period was not completed as of December 31, 2010.

1518 Retail Cost Variance Account – Retail

This account is used to recover the net difference between the revenue recovered from Retailer Service Agreements and billing options, and the cost of managing the retailer contracts.

For 2012 RSL is requesting disposition of the December 31, 2010 audited balance plus the forecast interest through April 30, 2012 for account 1518.

1521 Special Purpose Charge (SPC) Assessment Variance Account

$45,192 for the SPC assessment was remitted to the Minister of Finance in July of 2010. A separate sub-account was setup to record the amounts recovered from customers.

As per OEB's letters dated April 9 and April 23, 2011, Rideau St Lawrence Distribution Inc. is recovering the SPC assessment over a one-year period.

Included in this account, in error, as part of our 2010 Year End Accrual, was the amount of $18,391.97 set up for the Late Payment Penalty class action costs. This cost was Board approved for recovery based on EB-2010-0295, and the Board Decision issued Feb. 22, 2011. In 2011 this cost was correctly transferred to a Sub-account of 1508.

Per section 8 of the SPC Regulation, RSL is required to, and is seeking disposition of the forecast SPC residual balance at April 30th, 2012.

1525 Miscellaneous Deferred Debits Account

Rideau St Lawrence Distribution Inc. established account 1525 Miscellaneous Deferred Debits Account to include the cost of issuing refund cheques/credits to electricity consumers in accordance with government legislation. As part of the Board's Decision and Order for Rideau St Lawrence Distribution Inc.'s 2006 EDR Application (EB-2005-0414), part of this account balance was disposed of.

1531 Renewable Connection Capital Deferral Account

This account includes the amounts paid for capital investments related to "renewable enabling improvements" as defined in the OEB Guidelines G-2009-0087 Deemed Conditions of License: Distribution System Planning, June 16, 2009.

RSL is not requesting recovery of the balance in this account, as there is no significant balance in the account as of December 31, 2010 - $351.27.

1532 Renewable Connection OM&A Deferral Account

This account includes the amounts paid for incremental operating, maintenance, amortization and administrative expenses directly related to "renewable enabling improvements" as defined in the OEB Guidelines G-2009-0087 "Deemed Conditions of License: Distribution System Planning",

June 16, 2009, to track costs associated with renewable connection OM&A.

RSL is not requesting recovery for this account, as there is no balance in the account as of December 31, 2010.

1548 Retail Cost Variance Account – Service Transaction Request (STR)

This account is used to recover the net differences in costs specifically related to the Retailer Service Transaction Requests (STR), compared to the revenue produced from the transaction.

For 2012 RSL is requesting disposition of the December 31, 2010 audited balance plus the forecast interest through April 30, 2012 for account 1548.

1555 Smart Meter Capital and Recovery Offset Variance

This account records the net of the amounts paid for direct capital costs related to the smart meter program, and the amounts charged to customers using the OEB approved smart meter rate adder.

1555 Sub-account Capital and Sub-account Recoveries:

RSL is following the Smart Meter Funding and Cost Recovery Guideline dated December 15, 2011 (G-2011-0001) and is requesting a rate rider to recover the true-up revenue requirement from 2006 to 2011.

1555 Sub-account Stranded Meters:

RSL did not move stranded meter costs into this sub account, but left those costs in a sub account of 1860, and is requesting disposition those costs in 2012. The Stranded Meter costs, will be moved into this account when approved, and have been removed from the Cost Allocation run.

1556 Smart Meter OM&A Variance

This account records the incremental operating, maintenance, amortization and administrative expenses directly related to smart meters.

The audited balances up to August 31, 2011 (Special Interim Audit), and the 2011 Forecast costs (September to December), have been included in the revenue requirement true-up calculation.

1562 Deferred Payments in Lieu of Taxes

This account records the amount resulting from the OEB-approved PILs methodology for determining the deferral account allowance and the PILs proxy amount determined for periods ending April 30, 2006.

The Board conducted a combined proceeding EB-2008-0381 in order to determine the accuracy of the final account balances with respect to 1562 Deferred Payments on Lieu of Taxes, for the period Oct. 1, 2001 to April 30, 2006, for certain 2008 and 2009 distribution rate applications before the Board.

Procedural Order No. 6 issued on October 26, 2009, clarified which parties were applicants in the proceeding, and which parties were intervenors only. The three

Applicants that submitted evidence, namely, ENWIN, Halton Hills, and Barrie became the only applicants for this phase of the proceeding. The following distributors were named as applicants in the Notice and Procedural Order No. 1, were not required to submit evidence, but were made intervenors in this proceeding: Hydro Ottawa Limited, Sioux Lookout Hydro Inc., Oshawa PUC Networks Inc., Wellington North Power Inc., Rideau St. Lawrence Distribution Inc., Newmarket-Tay Power Distribution Ltd.

RSL has filed for disposition of this account following the principals set out in the combined proceeding found in decision EB-2008-0381. RSL has provided the relevant information required for disposition of the account as Exhibit 10.

1582 Retail Settlement Variance Account - One-time Wholesale Market Service

This account is used to record the net of non-recurring amounts not included in the Wholesale Market Service Rate charged by the IESO based on the settlement invoice and the amount charged to customers for the same services using the OEB-approved rate.

For 2012 RSL is requesting disposition of the December 31, 2010 audited balance plus the forecast interest through April 30, 2012 for account 1582.

1592 Deferred Tax Variances for 1 2006 and Subsequent Years

This account is used to record the tax impact of differences that result from a legislative or regulatory change to the tax rates or rules assumed in the 2006 OEB Tax Model, differences that result from a change in, or a disclosure of, a new assessing or administrative policy that is published by federal or provincial tax authorities, or any differences in 2006 PILs that result in changes in a distributor’s “opening” 2006 balances for tax accounts due to changes arising from a tax re-assessment for specific time periods.

RSL has no balance in this sub account, and no disposition is requested for 2012.

1592 Harmonized Sales Tax (HST) Deferral Account

RSL requests leave to discontinue tracking HST/OVAT/ITC as at December 31, 2011. RSL is filing a Cost of Service Rate Application, and as explained in Chapter 2 of the Filing Requirements, once RSL rebases, the HST impacts would be included in rates going forward.

RSL also requests the Board allow that account 1592 remain open, pending Board approval to discontinue tracking costs, and until such time as RSL files its 2014 IRM rate application at which time RSL will apply to the Board for an order to clear any audited debit or credit balance remaining in account 1592 Sub account HST.

3.0 ACCOUNT BALANCES

Table 9.4 contains the account balances from the Audited Financial Statements, as at December 31, 2010, and reconciled to the 2010 year end balances for RRR filing 2.1.7 Trial Balance as filed with the OEB.

Table 9.4

Deferral and Variance Account Balances

		Balances as of December 31, 2010		
		Principal	Interest	Total
Group 1				
RSVA - Low Voltage	1550	-64,580	-807	-65,387
RSVA - Wholesale Market Service Charge	1580	-156,917	-981	-157,898
RSVA - Retail Transmission Network Charge	1584	-146,961	-1,107	-148,068
RSVA - Retail Transmission Connection Charge	1586	-91,977	-1,401	-93,378
RSVA - Power - (excluding GA)	1588	-230,253	4,729	-225,524
RSVA - Power - Global Adjustment	1588	27,764	-3,038	24,726
Recovery of Regulatory Assets Balances	1590	195	4,561	4,756
Recovery of Regulatory Assets Balances - 2008	1595	-96	5,610	5,514
Recovery of Regulatory Assets Balances - 2010	1595	-377,917	377,875	-42
	Sub-Totals	-1,040,743	7,567	-655,301
Group 2				
Other Regulatory Assets - OEB Cost Assessments	1508	0	-59	-59
Other Regulatory Assets - Deferred IFRS Transistion Costs	1508	22,216	102	22,318
Other Regulatory Assets - Incremental Capital Costs	1508	4,352	31	4,383
Retail Cost Variance Account - Retail	1518	-471	1,194	723
Special Purpose Charge	1521	61,787	203	61,990
Renewable Generation Connection - Capital	1531	351	0	351
Retail Cost Variance Account - STR	1548	84,589	4,527	89,115
Smart Meters Capital	1555	1,091,031	4,056	1,095,087
Smart Meters Revenue	1555	-217,495	-3,004	-220,500
Smart Meter Expenses	1556	72,579	1	72,580
RSVA One Time	1582	6,356	1,145	7,502
PILs	1562	23,429	16,153	39,582
Deferred PILS Contra	1563	-23,429	-16,153	-39,582
Tax Variance - RITC	1592	-11,644	0	-11,644
Tax Variance - RITC Contra	1593	11,644	0	11,644
	Sub-Totals	1,125,295	8,195	1,133,490
Grand total - as at December 31, 2010		84,552	15,762	478,189

Table 9.6 contains the total claim for each account balance from the 2010 Audited Financial Statements, less any dispositions ordered by the Board during 2011, plus an interest projection to April 30, 2012. Table 9.10 in Schedule 8.0, shows the allocator (per the Board in the EDDVAR Report) used to calculate the Rate Riders, and the resulting recovery by customer

class. RSL is requesting disposition of these variance account balances, following the guidelines in the Report of the Board using the default disposition period of one year.

Smart Meter Project Costs have been removed from Group 1 and Group 2 costs, and disposition of those costs will be requested later in this application as a stand-alone request, in Exhibit 11, using the Smart Meter models provided by the Board.

RSL has provided a continuity schedule of the accounts as Appendix A to this exhibit.

Explanation of Continuity Schedule Variances:

Two adjustments were made to the Audited 2010 Year End balances and the RRR 2.1.7 Trial Balance reported numbers, before requesting disposition of the balances shown below.

RSL had an error in its billing system setup in 2010 for the Rate Rider for Global Adjustment Sub-account disposition – effective May 1, 2011, and applicable only to non RPP customers. The result was that instead of RSVA GA money collected going to GL 1595, it was added back into the GA Cost of Power Sub account, and the cost was claimed back from the IESO on the monthly power bill. This error was discovered in February 2011 as part of our year end work and analysis. Our 2010 monthly Revenue GL posting was corrected in 2010 prior to our Year End close. However as we had already settled with the IESO for the January 2011 power bill, we were not able to give the money back until the February Power bill was settled with the IESO - $237,267.02 was included in the $258,190.05 added to our February 2011 Power bill in line 142.

Because we have already returned the over collected amount, we have entered this amount in cell BI29 in the 2012_EDVAR_Continuity Schedule, thus reducing the refund we would be providing for the GA Sub-account. In 2010 we should also have corrected the cost of power variance account for this same amount, but we did not. It was corrected when we posted the February 2011 power bill.

The other account being adjusted is to 1562 Deferred PILS. After the Board issued its decision on combined proceedings on EB-2008-0381 (PILS), RSL reviewed and adjusted its transactions to reflect the Board Decision. This resulted in a net increase of $13,767 in Principal, and an increase of $5,985 increase in Interest Improvement. These amounts were entered in the EDVAR Continuity Schedule in cells BI68 and BN68, resulting in an increased claim amount of $19,762. Details are shown in PILS Exhibit 10.

Table 9.5 shows the quarterly Interest Rates applied to calculate the carrying charges for each regulatory deferral and variance account.

Table 9.5

Prescribed Interest Rates for Deferral / Variance Accounts

Quarter by Year[1]	Approved Deferral and Variance Accounts	CWIP Account
	Prescribed Interest Rate	Prescribed Interest Rate
Apr 2012	**1.47**	**3.92**
Q1 2012	**1.47**	**3.92**
Q4 2011	**1.47**	**3.92**
Q3 2011	1.47	4.29
Q2 2011	1.47	4.29
Q1 2011	1.47	4.29
Q4 2010	1.2	4.01
Q3 2010	0.89	4.66
Q2 2010	0.55	4.34
Q1 2010	0.55	4.34
Q4 2009	0.55	4.66
Q3 2009	0.55	5.67
Q2 2009	1.00	6.61
Q1 2009	2.45	6.61
Q4 2008	3.35	5.43
Q3 2008	3.35	5.43
Q2 2008	4.08	5.18
Q1 2008	5.14	5.18
Q4 2007	5.14	5.18
Q3 2007	4.59	5.18
Q2 2007	4.59	4.72
Q1 2007	4.59	4.72
Q4 2006	4.59	4.72
Q3 2006	4.59	5.05
Q2 2006	4.14	4.68

4.0 DEFERRAL AND VARIANCE ACCOUNTS REQUESTED

RSL is requesting the following new deferral or variance accounts:

- An IFRS Property, Plant and Equipment Deferral and Variance Account
  RSL is requesting an Accounting Order to establish a Deferral and Variance account to track the difference relating to PP&E components of rate base as a result of transition to modified IFRS in 2012, and in restating 2011 in MIFRS for comparison.

- Account 1595 – Sub-account 2012
  Upon approval of disposition, RSL is requesting Board approval to establish account 1595 – Sub-account 2012 to track costs, revenues and interest for amounts disposed of in RSL's 2012 Cost of Service Application.

- Account 1595 – Sub-account 2012 Global Adjustment
  Upon approval of disposition, RSL is requesting Board approval to establish account 1595 – Sub-account 2012 to track costs, revenues and interest for amounts disposed of in RSL's 2012 Cost of Service Application.

RSL is requesting the continuation of the following existing deferral or variance accounts:
Group 1

- 1550 – Low Voltage Variance
- 1580 – RSVA-Wholesale Market Service Charge
- 1584 – RSVA-Retail Transmission Network Charge
- 1586 – RSVA-Retail Transmission Connection Charge
- 1588 – RSVA-Power and Sub-Account Global Adjustment
- 1595 – Disposition and Recovery of Regulatory Balances - Sub-Account 2008
- 1595 – Disposition and Recovery of Regulatory Balances - Sub-Account 2010

Group 2

- 1508 – Other Regulatory Assets - Sub-Account Deferred IFRS Transition Costs
- 1508 – Other Regulatory Assets - Sub-Account Other
- 1518 – Retail Cost Variance Account - Retail
- 1525 – Miscellaneous Deferred Debits
- 1531 - Renewable Generation Connection Capital Deferral Account
- 1532 - Renewable Generation Connection OM&A Deferral Account
- 1534 - Smart Grid Capital Deferral Account
- 1535 - Smart Grid OM&A Deferral Account
- 1548 - Retail Cost 1 Variance Account - STR
- 1582 - RSVA - One-time
- 2425 - Other Deferred Credits
- 1592 – PILs and Tax Variance for 2006 and Subsequent Years and Sub-account HST/OVAT Input Tax Credits (ITCs)

RSL also requests the continuation of the following accounts:

- Account 1521 – Special Purpose Charge Assessment - As per the Board's instructions, RSL is recovering the SPC assessment over a one-year period.
  If the Board approves our request for final disposition, based on the forecast residual balance, as detailed later in this Exhibit, RSL withdraws this request for the account continuation.

- Account 1508 - Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs: This account includes amounts paid for one-time administrative incremental International Financial Reporting Standards (IFRS) transition costs not included in rates, until the transition to IFRS has commenced. RSL will be implementing IFRS as at January 1, 2012 and as a result, continues to incur costs associated with IFRS transition.

In 2010, the OEB approved sub-account 1508 IFRS Transition Costs, to record incremental costs incurred in relation to the transition to International Financial Reporting Standards (IFRS). The July 28, 2009 Report of the Board EB-2008-0408, Transition to International Financial Reporting Standards, stated *"As required by the Canadian Accounting Standards Board, Canadian Generally Accepted Accounting Principles (CGAAP) for publically accountable enterprises will transition to IFRS effective January 1, 2011".*

It was expected by the Board that incremental transition costs incurred after the January 1, 2011 were expected to be minimal.

On July 20 and 22, 2010, the International Accounting Standards Board (IASB) held deliberations on rate-regulated activities and made the decision to continue with its project addressing the recognition, measurement and disclosure of regulatory assets and liabilities, and not to develop transitional guidance for use by first-time adopters.

The Canadian Accounting Standards Board (AcSB) discussed these developments and decided to amend the CICA Handbook to require that qualifying entities with rate-regulated activities adopt IFRS for the first time no later than fiscal periods beginning on or after January 1, 2012.

As a qualifying entity, Rideau St Lawrence Distribution Inc. will be in a position to implement IFRS on January 1, 2012. Rideau St Lawrence Distribution Inc. therefore requests the continuation of the IFRS Transition Cost sub-account 1508 until December 31, 2012.

5.0 DEFERRAL AND VARIANCE ACCOUNTS REQUESTED FOR DISPOSITION

Rideau St Lawrence Distribution Inc. is requesting disposition of the variance accounts noted below, according to the Report of the Board EB-2008-0046, which states that "at the time of rebasing, all Account balances should be disposed of unless otherwise justified by the distributor or as required by a specific Board decision or guideline".

Rideau St Lawrence Distribution Inc. has followed the guidelines in the Report of the Board and requests disposition over a one-year period. Rideau St Lawrence Distribution Inc. has provided an excel version of the continuity schedule with its application filing titled "2012_EDDVAR_Continuity_Schedule-COS_RSL".

Rideau St Lawrence Distribution Inc. is requesting the disposition of following Group 1 and Group 2 Accounts shown in Table 9.6. These amounts are comprised of the audited balances as of December 31, 2010 less the 2010 IRM approved disposition, and the adjustments for the Global Adjustment Sub account and PILS (as explained earlier in this Exhibit), plus the forecasted interest through April 30, 2012.

Table 9.6

Deferral and Variance Account Balances requested for Disposition

Account Description	Account Number	Principal Amounts as of Dec-31 2010	Interest to Dec 31-10	Interest Jan-1 to Dec 31-11	Interest Jan 1-11 to Apr 30-12	Total Claim
RSVA - Low Voltage	1550	$ (19,563)	$ (1,544)	$ (288)	$ (96)	$ (21,490)
RSVA - Wholesale Market Service Charge	1580	$ (119,846)	$ 2,287	$ (1,762)	$ (587)	$ (119,908)
RSVA - Retail Transmission Network Charge	1584	$ (71,471)	$ 1,096	$ (1,051)	$ (350)	$ (71,776)
RSVA - Retail Transmission Connection Charge	1586	$ (23,748)	$ 9,239	$ (349)	$ (116)	$ (14,974)
RSVA - Power - (excluding GA)	1588	$ (82,103)	$ (10,891)	$ (1,207)	$ (402)	$ (94,604)
RSVA - Power - Global Adjustment	1588	$ (143,852)	$ (9,224)	$ (2,115)	$ (705)	$ (155,896)
Recovery of Regulatory Assets Balances	1590	$ -	$ 5,214	$ -	$ -	$ 5,214
Recovery of Regulatory Assets Balances	1595	$ (96)	$ 5,610	$ (1)	$ (0)	$ 5,512
Sub-Totals		$ (460,680)	$ 1,788	$ (6,772)	$ (2,257)	$ (467,921)
Other Regulatory Assets - OEB Cost Assessments	1508	$ (0)	$ (59)	$ (0)	$ (0)	$ (59)
Other Regulatory Assets - Deferred IFRS Transistion	1508					$ -
Other Regulatory Assets - Incremental Capital Costs	1508	$ 4,352	$ 31	$ 64	$ 21	$ 4,469
Retail Cost Variance Account - Retail	1518	$ (471)	$ 1,194	$ (7)	$ (2)	$ 714
Retail Cost Variance Account - STR	1548	$ 84,589	$ 4,527	$ 1,243	$ 414	$ 90,773
Smart Meters Revenue and Capital	1555					$ -
Smart Meters Revenue and Capital	1555					$ -
Smart Meter Expenses	1556					$ -
RSVA One Time	1582	$ 6,356	$ 1,145	$ 93	$ 31	$ 7,626
PILs	1562	$ 37,195	$ 22,139	$ 547	$ 182	$ 60,063
Tax Variance - RITC	1592		$ -	$ -	$ -	$ -
Sub-Totals		$ 132,021	$ 28,977	$ 1,941	$ 647	$ 163,585
Totals per column		$ (328,658)	$ 30,764	$ (4,831)	$ (1,610)	$ (304,336)

Deferred PILs Account 1562 details supporting the disposition claim are in Exhibit 10.

6.0 ACCOUNT 1521 – SPECIAL PURPOSE CHARGE (SPC):

RSL is requesting disposition of the forecast balance in this account, in agreement the Board letter addressed to all licensed electricity distributors, dated April 23, 2010.

The letter stated:

"In accordance with section 8 of the SPC Regulation, you are required to apply to the Board no later than April 15, 2012 for an order authorizing you to clear any debit or credit balance in "Sub-account 2010 SPC Variance". The Board expects that requests for disposition of the balance in "Sub-account 2010 SPC Variance" and "Sub-account 2010 SPC Assessment Carrying Charges" will be addressed as part of the proceedings to set rates for the 2012 rate year, except in cases where this approach would result in non-compliance with the timeline set out in section 8 of the SPC Regulation."

Table 9.7 shows the forecast SPC recovery shortfall with interest Improvement.

RSL is requesting disposition of this forecast shortfall. This amount is not material, and RSL proposes that the balance be transferred into 1595 for disposition at a later date, similar to the approach taken on EB-2009-0248, and EB-2010-0113 for the 50/50 sharing of changes in the tax level.

Table 9.7 Special Purpose Charge

Conservation and Renewable Energy Program Cost

Description	Paid in 2010	Recovered in 2010	Forecast for 2011	Forecast for 2012
SPC Assessment	45,192.00			
Billed Amounts	0.00	0.00	-37,047.60	-6,522.41
Carrying Charges	0.00	202.61	495.11	44.11
Total for Disposition	45,192.00	45,394.61	8,842.12	2,363.82

Comments:

Invoice for $45,192 paid to Ministry of Energy and Infrastructure in July 2010 .
Rates to bill the customer were not setup until effective Feb 15, 2011.

There will be a shortfall in billing recoveries, because of lower kWh usage.

	2011		2012	
	kwh	$$	kwh	$$
YTD Nov 2011 Billings	77,276,384	-28,816.80		
Forecast - Dec 2011	10,120,713	-3,775.03		
Forecast - Unbilled	11,945,755	-4,455.77		
Forecast - Jan - Feb 15			17,486,358	-6,522.41
		-37,047.60		

Forecast Source:	Dec 2011 using Dec 2010 billed kwhs
	Unbilled using 2010 Unbilled kwhs'
	2012 Fcst uses weather normal for Jan + 1/2 of Feb 2012

Table 9.8 is a copy of the SPC assessment paid to the Ministry of Energy and Infrastructure by RSL.

Table 9.8

Special Purpose Charge Assessment

Revised Invoice

Ministry of Energy and Infrastructure
Conservation and Renewable Energy Program Costs

Customer No./No du client	3706
Customer Site No./Nº d'emplacement du client	1061059
Invoice Date/Date de la facture	April 16, 2010
Invoice No./ Nº de la facture	50064
Due Date/ Date d'échéance	July 30, 2010
Payment Amount/ Montant remis	CAD $ 45,19[illegible]

To: Rideau St. Lawrence Distribution Inc.
985 Industrial Road, P.O. Box 699
Prescott, ON K0E 1T0
Attn: J. Walsh, President & CEO

Item Description:

Assessment for Ministry of Energy and Infrastructure Conservation and Renewable Energy Program Costs.
Quote part pour les coûts des programme de conservation et d'énergie renouvelable du ministère de l'énergie et de l'infrastructure.

Questions related to the remittance should be directed to the Non-Tax Revenue Management Branch Contact Centre at 1 877 535 0554 or fax (416) 326 5177. Les questions concernant la remise doivent être posées à l'InfoCentre de la Direction de la gestion des revenus non fiscaux au 1 877 535 0554 ou par télécopieur au 416 326-5177.

This assessment was calculated by the Ontario Energy Board, 2300 Yonge St. 27th Floor, P.O. Box 2319, Toronto, ON M4P 1E4 Questions related to the invoice should be directed to the Market Operations Hotline 416 440 7604. La présente quote part a été fixée par la Commission de l'énergie de l'Ontario, 2300, rue Yonge, 27e étage, case postale 2319, Toronto (Ontario) M4P 1E4. Les questions relatives à la facture doivent être posées au service de renseignements du service des opérations du marché : 416 440 7604.

Payments are to be made to the Minister of Finance not the Ontario Energy Board.
Les paiements doivent être faits au ministre des Finances et non à la Commission de l'énergie de l'Ontario.

Detach here/ Détacher ici

Ontario

Ministry of Finance/Ministère des Finances
Payment Processing Centre/Centre de traitement des paiements
33 King St. West/33 rue King Ouest
PO Box 646/CP 646
Oshawa, ON L1H 8X1

Customer No. / Nº du client	3706
Customer Site No./ Nº d'emplacement du client	1061059
Invoice No./ Nº de la facture	50064
Payment Amount / Montant remis	CAD $

Please detach and return this portion with your payment in the enclosed envelope. Make your cheque or money order payable to the Minister of Finance. Veuillez détacher et retourner cette partie avec votre paiement dans l'enveloppe-réponse. Libellez votre chèque ou votre mandat à l'ordre du ministre des Finances.

Rideau St. Lawrence Distribution Inc.
985 Industrial Road, P.O. Box 699
Prescott, ON K0E 1T0
Attn: J. Walsh, President & CEO

45 AR 50064

7.0 LOST REVENUE ADJUSTMENT MECHANISM ("LRAM"):

The Ontario Energy Board (OEB) introduced the LRAM/SSM processes outlined in the March 28, 2008 Guidelines for Electricity Distributor Conservation and Demand Management EB-2008-0037 ("CDM Guidelines") for rate-based applications to recover revenues lost to customer energy conservation, and to share in gains from effective CDM programs. Rideau delivered Ontario Power Authority (OPA) provincial programs from 2006 to 2010. CDM activities related to OPA-sponsored programs for 2006 through 2009 have already resulted in approval on EB-2010-0113 for foregone revenues of $53,268.56 for RSL.

RSL requested that Burman Energy Consultants Group Inc. (Burman Energy) prepare and critically assess an additional LRAM claim for program results to the end of 2010. Burman Energy used the most recently published OPA Final CDM Detailed Results, released November 15, 2011, to calculate the LRAM amounts claimed.

CDM activities in 2010 related to OPA-sponsored programs have resulted in foregone revenues of $31,149.47 for RSL as set out in the Burman Energy Report - Appendix 9A-D (LRAM Application RSL R1), and Appendix 9E LRAM Support.

Rideau seeks to remediate this lost revenue through Lost Revenue Adjustment Mechanism (LRAM). LRAM calculations are made from the energy savings data from measured CDM program results for OPA programming, which represent the potential for lost revenue to the LDC, and may be claimed under LRAM. The application for LRAM compensation is part of RSL's 2012 COS filing and is based on its 2010 OPA - CDM results.

Methodology:

LRAM was calculated as the product of demand/energy savings by customer class and the Board-approved variable distribution charge appropriate to each respective class (net of Regulatory Asset Recovery rate riders). OPA sponsored program kW/kWhs were deemed eligible for LRAM.

Results and Proposed Rider:

LRAM amounts were identified by rate class consistent with the CDM Guidelines for programs that impacted revenues from 2006 to 2010 for the OPA CDM programs. No forecast or other adjustment for the effects of CDM programs was made to the load quantities used in the preparation of RSL's rate cases in prior years. As set out in the CDM Guidelines, program net benefits are determined by the present value of the avoided electricity costs over the technology's/program's life minus the present value of program costs.

All results are net of free ridership. For all programs/projects, the most recently published OPA assumptions and measures list were used in LRAM calculations in accordance with OEB's direction letter, Conservation and Demand Management ("CDM") Input Assumptions Board File

No. EB-2008-0352, January 27, 2009 and consistent with the Decision and Order EB 2009-0192 for Horizon Utilities Corporation.

Table 9.9 provides the proposed LRAM rate rider calculation. RSL is proposing a one year volumetric rate rider based on the 2012 Test Year Annual Volumes as shown below.

Table 9.9

LRAM 2012 Proposed RateRider

Customer Rate Class	LRAM $	2012 Test Volumes		Proposed Rate	
		kwh	kW	kwh	kW
OPA Programs					
RESIDENTIAL	$20,898.88	44,584,446		0.0005	
GENERAL SERVICE <50KW	$7,676.75	19,806,495		0.0004	
GENERAL SERVICE >50KW	$2,573.83		126,652		0.0203
	$31,149.47				

8.0 DISPOSITION OF DEFERRAL AND VARIANCE ACCOUNTS

Allocators and Rate Riders:

Rideau St Lawrence Distribution Inc. submits the following Allocators in Table 9.10 used to assign the Group 1 and Group 2 balances to each rate class. Included in this Table is the resulting proposed Rate Rider.

Table 9.10

Deferral and Variance Accounts, Allocators, and Rate Riders

Deferral and Variance Accounts:	Amount	ALLOCATOR	Residential	GS < 50 KW	GS 50 - 4,999 kW	Street Lighting	Sentinel Lighting	Unmetered Scattered Load
1550	$ (21,490)	kWh	$ (9,165)	$ (4,072)	$ (7,846)	$ (296)	$ (22)	$ (88)
1580	$ (119,908)	kWh	$ (51,140)	$ (22,719)	$ (43,778)	$ (1,654)	$ (124)	$ (493)
1584	$ (71,776)	kWh	$ (30,612)	$ (13,599)	$ (26,205)	$ (990)	$ (74)	$ (295)
1586	$ (14,974)	kWh	$ (6,386)	$ (2,837)	$ (5,467)	$ (207)	$ (16)	$ (62)
1588 Excl GA	$ (94,604)	kWh	$ (40,348)	$ (17,924)	$ (34,540)	$ (1,305)	$ (98)	$ (389)
1588 - Global Adjustment	$ (155,896)	kwh - Non RPP	$ (21,682)	$ (8,891)	$ (119,930)	$ (5,393)	$ -	$ -
1590	$ 5,214	Proportion of Recovery	$ 1,993	$ 1,057	$ 2,087	$ 60	$ 4	$ 13
1595	$ 5,512	Proportion of Recovery	$ 2,572	$ 959	$ 1,923	$ 32	$ 8	$ 17
Subtotal - RSVA	$ (467,921)		$ (154,769)	$ (68,026)	$ (233,756)	$ (9,752)	$ (322)	$ (1,297)
1508	$ (59)	Dx Revenue	$ (34)	$ (11)	$ (11)	$ (2)	$ (0)	$ (1)
1508	$ -	Dx Revenue	$ -	$ -	$ -	$ -	$ -	$ -
1508	$ 4,469	Dx Revenue	$ 2,569	$ 848	$ 814	$ 184	$ 9	$ 45
1518	$ 714	# of Customers	$ 602	$ 92	$ 8	$ 1	$ 4	$ 7
1548	$ 90,773	# of Customers	$ 76,536	$ 11,748	$ 1,001	$ 92	$ 519	$ 878
1555	$ -							
1556	$ -							
1582	$ 7,626	kWh	$ 3,252	$ 1,445	$ 2,784	$ 105	$ 8	$ 31
1562	$ 60,063	kWh	$ 25,616	$ 11,380	$ 21,929	$ 828	$ 62	$ 247
1592	$ -	Dx Revenue	$ -	$ -	$ -	$ -	$ -	$ -
Subtotal - Non RSVA	$ 163,585		$ 108,541	$ 25,502	$ 26,525	$ 1,207	$ 602	$ 1,208
Total to be Recovered	$ (304,336)		$ (46,228)	$ (42,524)	$ (207,231)	$ (8,545)	$ 280	$ (89)
To be collected or refunded (Excl G A & Smart Meters)	$ (148,440)		$ (24,546)	$ (33,633)	$ (87,301)	$ (3,152)	$ 280	$ (89)
Number of years for Variable	1							
To be collected or refunded per year, Variable	$ (148,440)		$ (24,546)	$ (33,633)	$ (87,301)	$ (3,152)	$ 280	$ (89)

Class	Amount		Residential	GS < 50 KW	GS 50 - 999 kW	Street Lighting	Sentinel Lighting	Unmetered Scattered Load
Deferral and Variance Account Rate Riders, Variable (Excluding Global Adjustment)			$ (0.0006)	$ (0.0017)	$ (0.6893)	$ (0.8202)	$ 0.9301	$ (0.0002)
Billing Determinants			kWh	kWh	kW	kW	kW	kWh
Global Adjustment - to be collected or refunded	$ (155,896)		$ (21,682)	$ (8,891)	$ (119,930)	$ (5,393)	$ -	$ -
Number of years for Variable	1							
To be collected or refunded per year, Variable	$ (155,896)		$ (21,682)	$ (8,891)	$ (119,930)	$ (5,393)	$ -	$ -
Global Adjustment Rate Rider			$ (0.0005)	$ (0.0004)	$ (0.9469)	$ (1.4035)	$ -	$ -
Billing Determinants			kWh	kWh	kW	kW	kW	kWh

ATTACHMENT A

CDM Load Impacts by class and Program

ATTACHMENT A									
CDM Load Impacts by Class and Program									
		NET		GROSS		NET		GROSS	
Class	Year	2010		2010		2011		2011	
Program	Implemented	kWh	kW	kWh	kW	kWh	kW	kWh	kW
OPA Programs									
Residential									
Secondary Fridge Retirement Pilot	**2006**	6,154	1.39	6,838	1.55	6,154	1.39	6,838	1.55
Cool & Hot Savings Rebate	**2006 - 2007**	39,136	30.06	66,274	50.65	39,136	30.06	66,274	50.65
Every Kilowatt Counts	**2006 - 2007**	192,600	9.69	249,094	12.26	192,600	9.69	249,094	12.26
Great Refrigerator Roundup	**2007-2010**	289,910	41.11	568,301	83.54	289,755	40.38	567,941	81.85
Summer Savings	**2007**	7,199	9.07	59,995	75.59	7,199	9.07	59,995	75.59
Social Housing – Pilot	**2007**	13,045	1.53	13,045	1.53	13,045	1.53	13,045	1.53
Cool Savings Rebate Program	**2008-2010**	113,664	71.58	254,129	157.79	113,664	70.76	251,540	155.91
Every Kilowatt Counts Power Savings Event	**2008-2010**	205,064	14.32	506,781	35.60	202,551	14.24	506,660	35.60
peaksaver®	**2007-2010**	0	0.00	0	0.00	0	0.00	0	0.00
Summer Sweepstakes	**2008**	27,676	11.13	35,671	14.34	27,676	11.13	35,671	14.34
General Service<50kW									
High Performance New Construction	**2008-2010**	31,033	13.79	44,333	19.69	31,033	13.79	44,333	19.69
Power Savings Blitz	**2008-2010**	484,395	137.62	501,657	142.18	484,395	137.62	501,657	142.18
Multifamily Energy Efficiency Rebates	2010	3,272	0.28	4,442	0.36	3,272	0.28	4,442	0.36
General Service>50kW to 4,999kW									
Demand Response 1	**2006 -2010**								
Demand Response 2	**2009-2010**	111,266	95.19	111,266	95.19	0	0.00	0	0.00
Demand Response 3	**2008-2010**	3,944	201.34	3,944	201.34	0	0.00	0	0.00
Electricity Retrofit Incentive Program	**2007-2010**	351,150	55.92	568,695	90.76	351,150	55.92	568,695	90.76
Loblaw & York Region Demand Response	**2006-2010**	0	23.37	0	23.37	0	0.00	0	0.00

ATTACHMENT B

LRAM Amounts

ATTACHMENT B												
Foregone Revenue by Class and Program												
		2009		2010				2011				
Class Program	Year Implemented	kWh or kW	Rate per Unit	Load Unit	kWh or kW	Rate per Unit	Revenue	Load Unit	kWh or kW	Rate per Unit	Revenue	Total Revenue
OPA Programs												
Residential												
Secondary Fridge Retirement Pilot	2006	kWh	0.0117	6,154	kWh	0.0117	$72.01	6,154	kWh	0.0117	$72.01	$144.01
Cool & Hot Savings Rebate	2006 - 2007	kWh	0.0117	39,136	kWh	0.0117	$457.89	39,136	kWh	0.0117	$457.89	$915.79
Every Kilowatt Counts	2006 - 2007	kWh	0.0117	192,600	kWh	0.0117	$2,253.42	192,600	kWh	0.0117	$2,253.42	$4,506.84
Great Refrigerator Roundup	2007-2010	kWh	0.0117	289,910	kWh	0.0117	$3,391.95	289,755	kWh	0.0117	$3,390.13	$6,782.07
Summer Savings	2007	kWh	0.0117	7,199	kWh	0.0117	$84.23	7,199	kWh	0.0117	$84.23	$168.47
Social Housing – Pilot	2007	kWh	0.0117	13,045	kWh	0.0117	$152.63	13,045	kWh	0.0117	$152.63	$305.25
Cool Savings Rebate Program	2008-2010	kWh	0.0117	113,664	kWh	0.0117	$1,329.87	113,664	kWh	0.0117	$1,329.87	$2,659.75
Every Kilowatt Counts Power Savings Event	2008-2010	kWh	0.0117	205,064	kWh	0.0117	$2,399.25	202,551	kWh	0.0117	$2,369.84	$4,769.09
peaksaver®	2007-2010	kWh	0.0117	0	kWh	0.0117	$0.00	0	kWh	0.0117	$0.00	$0.00
Summer Sweepstakes	2008	kWh	0.0117	27,676	kWh	0.0117	$323.81	27,676	kWh	0.0117	$323.81	$647.61
												$20,898.88
GENERAL SERVICE Less Than 50kW												
High Performance New Construction	2008-2010	kWh	0.0074	31,033	kWh	0.0074	$229.64	31,033	kWh	0.0074	$229.64	$459.29
Power Savings Blitz	2008-2010	kWh	0.0074	484,395	kWh	0.0074	$3,584.52	484,395	kWh	0.0074	$3,584.52	$7,169.04
Multifamily Energy Efficiency Rebates	2010	kWh	0.0074	3,272	kWh	0.0074	$24.21	3,272	kWh	0.0074	$24.21	$48.43
												$7,676.75
General Service>50kW to 4,999kW												
Demand Response 1	2006 -2010	kW	1.2613	0.00	kW	1.2473	$0.00	0.00	kW	1.2473	$0.00	$0.00
Demand Response 2	2009-2010	kW	1.2613	95.19	kW	1.2473	$118.73	0.00	kW	1.2473	$148.09	$266.82
Demand Response 3	2008-2010	kW	1.2613	201.34	kW	1.2473	$251.13	0.00	kW	1.2473	$313.23	$564.35
Electricity Retrofit Incentive Program	2007-2010	kW	1.2613	55.92	kW	1.2473	$840.15	55.92	kW	1.2473	$837.02	$1,677.16
Electricity Resources Demand Response	2006-2010	kW	1.2613	23.37	kW	1.2473	$29.14	0.00	kW	1.2473	$36.35	$65.49
												$2,573.83
												$31,149.47

ATTACHMENT C

LRAM Totals

	LRAM 2012 Proposed RateRider				
Customer Rate Class	**LRAM $**	**2012 Test Volumes**		**Proposed Rate**	
		kwh	**kW**	**kwh**	**kW**
OPA Programs					
RESIDENTIAL	$20,898.88	44,584,446		0.0005	
GENERAL SERVICE <50KW	$7,676.75	19,806,495		0.0004	
GENERAL SERVICE >50KW	$2,573.83		126,652		0.0203
	$31,149.47				

ATTACHMENT D

OPA Assumptions for OPA Conservation & Demand Management Programs

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ATTACHMENT E

LRAM Support

Revised Invoice

Ministry of Energy and Infrastructure
Conservation and Renewable Energy Program Costs

Customer No./No du client **3706**
Customer Site No./ N° d'emplacement du client 1061066
Invoice Date/Date de la facture **April 16, 2010**
Invoice No./ N° de la facture 50064
Due Date/ Date d'échéance **July 30, 2010**
Payment Amount/ Montant remis **CAD $ 45,192**

To: Rideau St. Lawrence Distribution Inc.
985 Industrial Road, P.O. Box 699
Prescott, ON K0E 1T0
Attn: J. Walsh, President & CEO

Item Description:

Assessment for Ministry of Energy and Infrastructure Conservation and Renewable Energy Program Costs.
Quote-part pour les coûts des programme de conservation et d'énergie renouvelable du ministère de l'Énergie et de l'Infrastructure.

Questions related to the remittance should be directed to the Non-Tax Revenue Management Branch Contact Centre at 1-877-535-0554 or Fax (416) 326-5177. Les questions concernant la remise doivent être posées à l'InfoCentre de la Direction de la gestion des revenus non fiscaux au 1 877 535-0554 ou par télécopieur au 416 326-5177.

This assessment was calculated by the Ontario Energy Board, 2300 Yonge St. 27th Floor, P.O. Box 2319, Toronto, ON M4P 1E4.Questions related to the invoice should be directed to the Market Operations Hotline 416-440 -7604. La présente quote-part a été fixée par la Commission de l'énergie de l'Ontario, 2300, rue Yonge, 27e étage, case postale 2319, Toronto (Ontario) M4P 1E4. Les questions relatives à la facture doivent être posées au service de téléassistance du service Activités du marché : 416 440-7604.

Payments are to be made to the Minister of Finance not the Ontario Energy Board.
Les paiements doivent être faits au ministre des Finances et non à la Commission de l'énergie de l'Ontario.

Detach here/ Détacher ici

Ontario

Ministry of Finance/Ministère des Finances
Payment Processing Centre/Centre de traitement des paiements
33 King St. West/33 rue King Ouest
PO Box 647/CP 647
Oshawa, ON L1H 8X3

Customer No. / N° du client 3706
Customer Site No./ N° d'emplacement du client 1061066
Invoice No./ N° de la facture **50064**
Payment Amount / Montant remis **CAD $** .

Please detach and return this portion with your payment in the enclosed envelope. Make your cheque or money order payable to the Minister of Finance. Veuillez détacher et retourner cette partie avec votre remise dans l'enveloppe ci-jointe. Libellez votre chèque ou votre mandat à l'ordre du ministre des Finances.

Rideau St. Lawrence Distribution Inc.
985 Industrial Road, P.O. Box 699
Prescott, ON K0E 1T0
Attn: J. Walsh, President & CEO

45 AR 50064

98 Archibald Road, Kettleby, Ont. L0G 1J0 ● Phone: 1-877-662-5489 ● Fax: 905-939-4606 ● Email: info@burmanenergy.ca ● www.burmanenergy.ca

Attachment E

Rideau St. Lawrence Distribution

LRAM Support

November 24, 2011

Prepared by: Bart Burman, MBA, BA.Sc. P.Eng., President

Table of Contents

1. Introduction

With success in its CDM activities, Rideau St. Lawrence Distribution has lost revenues that need to be addressed as part of its 2012 rates submission to the Ontario Energy Board (OEB). This process will ensure that future CDM investments are sustainable in the long term by becoming a standard element in future rate filings.

The Ontario Energy Board (OEB) introduced a process outlined in the March 28, 2008 Guidelines for Electricity Distributor Conservation and Demand Management EB-2008-0037) ("CDM Guidelines") for rate-based applications to recover revenues lost to customer energy conservation, and to share in gains from effective CDM programs prior to the completion of Third Tranche CDM programs. The mechanism developed by the OEB to calculate lost revenue for savings is the Lost Revenue Adjustment Mechanism (LRAM).

2. Scope

Rideau St. Lawrence Distribution requested that Burman Energy Consultants Group Inc. (Burman Energy) prepare and critically assess an additional LRAM claim for program results to the end of 2010. The most recently published OPA Final 2010 CDM Detailed Results, released November 15, 2011, were used to calculate LRAM amounts.

Burman Energy committed to providing the following:

1. Review available suitability of published Rideau St. Lawrence Distribution data for determining appropriate input assumptions.

2. Prepare and finalize LRAM calculations and assumptions consistent with CDM Guidelines and suitable for inclusion in Rideau St. Lawrence Distribution' 2012 COS application, with supporting details.

3. Produce a report, recommendations, and support related to LRAM assessments/findings.

In performing the above tasks, Burman Energy's involvement is intended to constitute a third party review as specified in the OEB's CDM Guidelines.

3. LRAM Principles

The OEB issued GUIDELINES FOR ELECTRICITY DISTRIBUTOR CONSERVATION AND DEMAND MANAGEMENT, EB-2008-0037 were applied to the preparation of this LRAM application.

LRAM was calculated as the product of the demand/energy savings by customer class and the Board-approved variable distribution charge appropriate to each respective class (net of Regulatory Asset Recovery rate riders) for Rideau St. Lawrence Distribution.

The OPA published program evaluation reports were utilized where available in the validation of input assumptions.

4. Process

In calculating LRAM, Burman Energy:

1. Reviewed existing LRAM CDM Guidelines and precedents set through LDC submissions to the OEB, to identify the most prudent course for Rideau St. Lawrence Distribution LRAM.

2. Sought counsel within OEB staff to validate assumptions and processes to complete LRAM submission consistent with other LDC submissions.

3. Reviewed Rideau St. Lawrence Distribution' CDM program results and input assumptions.

4. Verified correct input assumptions were applied in LRAM calculations.

5. Prepared report and recommendations related to LRAM calculations consistent with OEB CDM Guidelines which are in the accompanying documentation.

5. Results

A review of Rideau St. Lawrence Distribution's CDM program supporting data verified that documentation exists to support the use of OPA program evaluations as the basis for LRAM calculations. Input assumptions and free ridership rates for 2006-2010 programs are identified in Attachment D

The accompanying table below summarizes the calculated amounts for LRAM for Rideau St. Lawrence Distribution's OPA programs. The calculation of the results, by program and customer class as applicable, are explained in the text below, and detailed in the appended attachment.

Rate Class	LRAM $
OPA Programs	
RESIDENTIAL	$20,898.88
GENERAL SERVICE <50KW	$7,676.75
GENERAL SERVICE >50KW	$2,573.83
	$31,149.47

6. Calculation of LRAM

OPA sponsored programs represent lost revenue through their successful implementation and are included in LRAM calculations.

LRAM amounts were identified by rate class consistent with the CDM Guidelines for programs that impacted revenues from 2006 to 2010 for OPA programs. No adjustments were made to incorporate impacts for any kW/kWh reductions assumed in current Board approved load forecasts.

The sum of all program LRAM calculations, including OPA sponsored programs is $31,149.47

Attachment A summarizes load impacts by class and program. Attachment B (Foregone Revenue By Class and Program) summarizes the CDM load impacts by program and rate class and the resultant revenue impacts.

The LRAM amounts arising from CDM programs in each respective rate class are allocated to that class for recovery.

7. Recommendations

Burman Energy recommends the following:

1. LRAM amounts arising from CDM programs in each rate class be allocated to that class for recovery.

2. Prepare adjustments to account for any kW/kWh savings amounts included in current load forecasts.

3. Rate impacts, proposed rate riders and respective terms to mitigate LRAM recovery be addressed by Rideau St. Lawrence Distribution

Exhibit 11 — Smart Meter Final Disposition

Schedule	**Contents of Schedule**
1.0	INTRODUCTION
2.0	STATUS OF IMPLEMENTATION OF SMART METERS
3.0	RECOVERY OF SMART METER FUNDING
4.0	PROJECT OVERVIEW
5.0	PROJECT SPECIFICS
5.1	AMI Selection:
5.2	Meter Deployment:
6.0	BUSINESS PROCESS REDESIGN
7.0	SYSTEM CHANGES
8.0	INTEGRATION WITH MDM/R
9.0	TRANSITION TO TIME OF USE PRICING
10.0	CUSTOMER EDUCATION
11.0	WEB PRESENTMENT
12.0	ANNUAL SECURITY AUDIT
13.0	COPIES OF AGREEMENTS
14.0	JUSTIFICATION FOR FUNCTIONALITY THAT EXCEEDS MINIMUM FUNCTIONALITY

1.0 INTRODUCTION

This application is filed by Rideau St. Lawrence Distribution Inc. (RSL), for cost recovery of the mandatory Smart Meter Project implementation of smart meters in the LDCs service area. The cost recovery is based on actual costs incurred to December 31, 2010, plus actual audited costs until August 31, 2011(External Auditors performed a Special Interim Audit for January 1 to August 31, 2011, on actual Smart Meter Capital and Smart Meter OM&A costs in accounts 1555 and 1556), and forecast costs from September 1, 2011 until December 31, 2011.

The application has been filed based on the December 15, 2011 “G-2011-0001 Guideline Smart Meter Funding and Cost Recovery – Final Disposition”, and RSL data has been input into the updated Smart Meter Model, version 2.17.

RSL is specifically requesting the following:

- Approval to include Smart Meter Gross Fixed Asset Capital costs as of December 31, 2011 of $1,294,090 into RLS’s 2012 Cost of Service Rate Base. Capital Cost details are provided in the completed Smart Meter Model attached to this Exhibit, and as part of this Exhibit, in Table 15.1.

- A Smart Meter Disposition Rate Rider (SMDR) of $0.85 per Residential customer, and %1.53 per GS <50kW, per month for a one (1) year period commencing May 1, 2012, to collect the net Deferred Revenue Requirement of $64,983.33. This rate rider is the true-up for the Smart Meter Projects costs incurred to December 31, 2011 ($499,649.82), less the forecast Revenues collected from 2006 until April 30th, 2012 ($434,666.49).

- Approval to recover Stranded Meter costs through a Rate Rider of $2.02 per Residential customer, and $6.24 per GS <50kW, per month, for a one (1) year period from May 1, 2012 until April 30, 2013.

Collaboration of LDCs:

RSL participated with LDCs within the Cornerstone Hydro Electric Concepts Association (CHEC) to implement smart meters in a cost effective manner. The collaborative initiative assisted LDCs in the development of project plans, RFPs and contract evaluations. As part of the collaborative effort CHEC LDCs entered into a professional services agreement with Util-Assist Inc., an Ontario consulting firm specializing in metering solutions and technologies, to assist with the development of the project plan, RFPs, evaluations, award of contract, project monitoring, problem solving and reporting. The cost benefit of the services agreement was reviewed and renewed in January of 2010. Review documents are included in Addendum 6 as confidential material.

CHEC is a not-for-profit member owned organization that provides value added services to their Local Distribution Companies (LDC) members. CHEC strives to reduce LDC costs through sharing of knowledge and information as well as providing savings through joint purchasing of goods and services with its members.

The twelve LDCs which form CHEC represent a customer base of approximately 100,000 customers. The existing members in CHEC include the following LDCs:

Centre Wellington Hydro
COLLUS Power
Innisfil Hydro
Lakefront Utilities
Lakeland Power Distribution
Midland Power Utility
Orangeville Hydro
Parry Sound Power
Rideau St. Lawrence Distribution
Wasaga Distribution
Wellington North Power
West Coast Huron Energy.

Cornerstone Hydro Electric Concepts Association (CHEC) is an incorporated body that is governed by a Board of Directors. The Board of Directors and Executive are voluntary positions from staff of the member Local Distribution Companies (collectively, “LDCs” or “Member LDC’s”). CHEC’s vision is “to be recognized as the premier LDC Cooperative in the province, by meeting or exceeding member expectations through the sharing of services, opportunities, knowledge and resources.” CHEC is built on sharing between LDCs through committees, staff and consultant positions, shared documents, specific working groups, combined projects and informal communications between members and staff.

The MDMR Project represents a project where LDCs working together achieve economies and successful implementation.

2.0 STATUS OF IMPLEMENTATION OF SMART METERS

RSL has installed a total of 5,775 Meters as of December 31, 2011, which represents 100% of Residential and GS < 50 kW meters. This application seeks the recovery of the revenue requirements in respect of these smart meters with a gross capital cost of $1,294,090.

Capital costs beyond minimum functionality are shown in Category 1.6.3. These costs are for web presentment, and CIS modifications for Time-of-Use (TOU) billing, totalling $20,800. RSL has included these cost in our recovery request, as they are mandatory items, and are not MDMR costs. RSL has not included any other costs for services that are above the “Minimum Spec”.

RSL has not included any in house labour costs in Capital or OM&A costs for this project.

3.0 RECOVERY OF SMART METER FUNDING

Since 2006 RSL has been collecting funds associated with smart meter implementation. The basis for the recovery is outlined below:

- In the 2006 Decision and Order (EB-2005-0414) in accordance to the Generic Decision which provided $0.30 per month, per residential customer, to be added to LUI's revenue requirement. A monthly fixed charge of $0.26 metered customer per month effective May 1, 2006, was billed and the proceeds were credited in OEB Account 1555, Smart Meter Capital and Recovery Offset Variance Account.

- In the 2007 Decision and Order (EB-2007-0575), RSL received approval to continue the $0.26 per metered customer per month smart metering funding charge for the 2007 IRM rate year.

- In the 2008 Decision and Order (EB-2007-0762), RSL received approval to continue the $0.26 per metered customer per month smart metering funding charge for the 2008 rate year, commencing June 13, 2008.

- In the 2009 Decision and Order (EB-2008-0210), RSL received approval to increase the smart meter funding adder to $1.00 per metered customer per month for the 2009 IRM Rate Year.

- In its 2010 IRM Decision and Order (EB-2009-0248), RSL received approval for the smart meter funding adder of $2.00 per metered customer per month.

- In its 2011 IRM Decision and Order (EB-2010-0095), RSL received approval from the Board for a smart meter funding adder of $2.50.

Table 3.0

Smart Meters Installed and Smart Meter Funding

Year	Smart Meters Installed			Percentage	Account 1555		Account 1556
	Residential	GS < 50 kW	Other [1]	of applicable customers converted	Funding Adder Revenues Collected	Capital Expenditures	Operating Expenses
				%	$	$	$
2006	-				-$ 12,004	$ 6,521	$ -
2007		-	-		-$ 17,977	$ 10,775	$ -
2008					-$ 17,822	$ 24,879	$ -
2009	4,532	660		90.00	-$ 52,241	$ 844,778	$ 3,199
2010	311	10		97.30	-$ 117,253	$ 276,758	$ 72,893
2011 and beyond (if required)	162	100		100.00	-$ 222,300		$ 6,270

4.0 PROJECT OVERVIEW

Addendum 1 is a project summary prepared by Util-Assist which outlines the various stages of the project and the due diligence undertaken at each step. The report, prepared on behalf of CHEC, outlines the details of each process, the RFPs undertaken, evaluations and the award of contracts.

CHEC LDCs recognized the benefits of collaboration early in the process through participation in the Ontario Utilities Smart Meter (OUSM) working group. Involvement in the OUSM group continued along with the engagement of Util Assist for specific project management. The details of the implementation project and the prudence reviews are outlined in Addendum 1 and include:

- Participation in Ministry of Energy and Infrastructure authorized London Hydro AMI RFP process (establishing best practice procurement procedures)
- ODS RFP and award of contracts
- WAN RFP and award of contracts
- Meter Disposal RFQ
- Installation Service Provider RFP and award of contracts.

The RFPs are included in the addendums.

Evaluations for each RFP are considered confidential material and have not been submitted with this Application.

RSL will provide additional information, on an as needed basis, subject to the Board Rules of Confidentiality.

5.0 PROJECT SPECIFICS

5.1 AMI Selection:

Based on the London Hydro AMI RFP process RSL was awarded Elster's Energy Axis AMI system as the preferred vendor by the Fairness Commissioner (refer to the Attestation Letter of the Fairness Commissioner attached as Addendum 2).

5.2 Meter Deployment:

Based on the RFP process and evaluation it was determined that Trilliant most closely met the requirements for the mass deployment of meters. Addendum 3 contains the RFP for the award of contract.

Shortly after Trilliant was selected as the winning proponent, Olameter acquired Trilliant resulting in Olameter providing the deployment services. The impact of this ownership change was evaluated and based on the existing relationship between Olameter and the LDCs and their performance in the industry, awarding the contract was deemed appropriate.

The mass deployment of meters started on July 6, 2009, and was scheduled to be completed by December 1, 2009. By the schedule date a total of 5,192 of 5,775 (90%), meters were installed.

The expected 10% shortfall was caused by a large number of inside services, requiring appointments, and by required transformer type meters that the installers were not qualified to install.

Operational Data Store (ODS) Functionality:

With the implementation of the AMI system a need was recognized for an application that supported full integration with the MDM/R and enabled staff to audit, validate, interact with and gain valuable business information from the wealth of meter data that was being collected. The AMI system, while fully capable of collecting meter read data and forwarding that raw data to the MDM/R, does not provide all of the functionality necessary to interpret and/or leverage the information it is providing in an educated and meaningful fashion.

An RFP was issued for an operational data store (ODS) in November 2008. Following the RFP process, shortlisted vendors delivered software demonstrations, leading to the selection of Kinetiq as the preferred vendor with their ODS application. Addendum 4 contains the RFP for the award of contract.

The primary requirements and features of the operational data store (ODS) are:

a) Dashboard of Field Issues Possibly Requiring Intervention - Dashboard visibility to the real-time performance of the smart meter system to provide field staff with visibility to troubleshooting priorities such as non-communicating meters, non-communicating tower gateways/collectors, etc.

b) AMI SLA Audit - Audit and reporting / real-time notification capabilities to monitor AMI performance and therefore ensure that data collection and submission service-level agreements (SLAs) with the centralized MDM/R are consistently met.

c) Read Re-submission - The ODS will provide a data repository to facilitate backfilling reads after a meter installation, front-filling reads after a meter removal, and replacing reads labeled as NVE (Needs Verification or Edit) by the IESO MDM/R system. The ODS will provide a mechanism for meter data editing and VEE (Validation, Estimation and Editing) processes (in keeping with the MDM/R specifications), such data can then be re-submitted to the MDM/R. Features such as “register read validation failure resolution” will be invaluable.

d) IESO MDM/R Report Integration / Issue Resolution Automation - The MDM/R produces a large volume of reports on a daily or regular basis each potentially containing large amounts of information. Kinetiq will load the MDM/R reports, and filter the information they provide in order to provide manageable, meaningful action items that can be prioritized, investigated and resolved.

e) Meter Event Monitoring - Dashboard visibility to report meter events and indicators such as outages, restorations, tampers, voltage changes, etc., many of which will afford the opportunity to improve the safety and reliability of the distribution system.

f) Revenue Protection – LDCs will be able to identify and respond to meter tampers which historically would have resulted in unidentified theft of power

g) Outage Reporting - Real-time outage information to facilitate faster response time, and therefore improved system reliability, a future benefit.

6.0 BUSINESS PROCESS REDESIGN

Throughout the latter half of 2010, the Util-Assist training team delivered a series of education sessions covering the MDM/R design specifications, meter read data, VEE and other billing processes, and the design of a testing/cutover strategy. LDCs have widely recognized that a number of business processes, including new account setup, meter installations, meter changes, move-in/move-out and final billing all require scrutiny and procedural modifications to ensure that MDM/R integrations are optimized. Actual business process redesign is an ongoing process leading up to and after cutover.

7.0 SYSTEM CHANGES

Modifications or additional modules to the existing Harris billing system were undertaken as part of the smart meter deployment and readiness for the implementation of time of use billing. It was fully expected that existing systems could be modified to accommodate as illustrated by the successful implementation of time of use billing in other LDCs. The required add-ons software modules and professional services for the existing system, to ensure the integration was completed in the defined regulatory timelines, were implemented.

8.0 INTEGRATION WITH MDM/R

To assist with the integration to the provincial Meter Data Management Repository (MDM/R) staff attended relevant IESO training sessions as well as further training sessions provided by Util-Assist.

Registration paperwork and integration project plan were filed with the IESO, and approved on September 6, 2010. AS2 connectivity software to facilitate data integration with the MDM/R was selected and installed in December 21, 2010, and connectivity testing was completed with the IESO on April 13, 2011.

The project plan called for Unit Testing to be executed in April 29, 2011, but due to delays, was completed on August 5, 2011, and System Integration (SIT) was completed on August 26, 2011, and Qualification Testing (QT) on October 21, 2011, in preparation for the planned cutover to live data transfer with the MDMR by December 31, 2011.

The ability to meet these targeted timelines was to a large extent contingent upon various software systems delivering the promised functionality and suppliers meeting their contractual obligations. Cutover to production was attained on October 21, 2011.

9.0 TRANSITION TO TIME OF USE PRICING

In mid-2010, the Ontario Government articulated an expectation that 1 million RPP customers would be billed using TOU pricing by the Summer of 2011, rising to 3.6 million customers by June 2012. On June 24, 2011, the Ontario Energy Board issued a proposed determination regarding mandated time-of-use pricing for regulated price plan customers (Board File No. EB-2011-0218), suggesting that distributor-specific TOU dates would be the most appropriate approach, as it allows for the deadline to logically follow MDM/R enrolment activities.

RSL's target date was December 31, 2011.

Rideau is currently completing the mandatory testing requirements for their entry to R7.2 of the MDMR. Tests have been submitted and verified complete by the MDMR for the 20 mandatory tests. Rideau had planned and pointed its systems to the R7.2 interface that is Measurement Canada complaint. On November 30th Rideau received communication from the IESO announcing a delay in the promotion of the R7.2 to the production environment, which would have allowed Rideau to bill TOU as per their plan. The original mid-January timeframe availability of Measurement Canada R7.2 compliant version, coincided with Rideau's planned TOU cutover plan.

At this time we are not aware that Measurement Canada has released LDC's from their obligations of ensuring compliance with their February 10, 2010 bulletin. Subsequent to that, on June 3rd a letter was sent to LDC's that reminding them of this obligation. The letter went on to say – "Where a contractor is currently in non-compliance with the above noted requirements, appropriate and corrective actions must be implemented such that full compliance is achieved by January 1, 2012".

Rideau is aware that meetings are taking place to arrive at the best solution to ensure that all metering technologies currently deployed in the province will be able to meet Measurements Canada's requirements. Our last update was that the IESO is targeting a solution to be implemented in March 2012, and that the Ministry of Energy will be providing updates to Measurement Canada.

Rideau is currently compliant with Measurement Canada requirements, as we are providing register reads, and are not planning to move to TOU billing using R7.0, as it is non-compliant with Measurement Canada.

Once the IESO has moved R7.2 into production, Rideau will request permission to move the TOU billing using R7.2.

The IESO, in their November 30th communication encouraged LDCs to continue testing in R7.2 thus reducing the time it would take to move to R7.2 once it is available.

10.0 CUSTOMER EDUCATION

RSL has mailed to their customers a “Welcome package” which included a letter of introduction, a brief explanation of TOU rates and a general statement about the expected change over to TOU billing dates. The package also included two brochures – Introducing Time-Of-Use Rates and Managing Your Electricity Costs; and removable decals displaying the TOU rates and the TOU Time periods. Packages were prepared for both our residential customers and our small business customers.

We intend to provide our customers with a second mail out package which will include a letter giving a more definitive date for the change to TOU billing and actual consumption data. It will provide them with two months of their actual historical consumption and will show a comparison for the electricity commodity charges – for charges which they have received under the RPP traditional pricing for and the RPP TOU pricing had it been in effect - with the variance for the month.

11.0 WEB PRESENTMENT

RSL has arranged to Web Presentment with a Third Party vendor, the ITM Group.

The web presentment piece is to be launched coincident with the TOU billing dates.

12.0 ANNUAL SECURITY AUDIT

With the mass deployment of AMI systems, security of the AMI network is critical to prevent utilities from becoming susceptible to new levels of potential security breaches and to ensure customer privacy and acceptance of the network. By installing network infrastructure in the field, there is now a requirement for additional security measures in order to ensure that utility data and equipment are kept secure from manipulation or other forms of control. As networks are deployed throughout the world, cyber security articles and reports with reports of the potential for smart-grid hacking are becoming commonplace in the media. The minimum Functional Specification for an Advanced Metering Infrastructure (AMI) released in July 2006 identified the need for security within the AMI network – Section 2.11 Security and Authentication: "The AMI shall have security features to prevent unauthorized access to the AMI and meter data and to ensure authentication to all AMI elements." Some of the privacy and network security infrastructure concerns that have been raised include:

- Monitoring a consumer's usage;
- Modifying one's own, or another consumer's usage;
- Interrupting the power of one or more consumers; and
- Tampering with demand side management tools which can be controlled through smart meters.

Since early 2009, Ontario utilities have been working with their smart meter providers to understand the security features of the networks, best practices for their deployment and new features that are being developed for future implementation within the smart meter networks. In November 2009 the Information and Privacy Commissioner of Ontario released the report Smart Privacy for the Smart Grid which identified areas of concern to be addressed in the area of smart meter and smart grid devices.

Going forward, annual security audit has been budgeted, as this is a prudent approach to satisfying the due diligence requirements for protection not only of the customer information, but also to ensure that access to the infrastructure is properly protected, thereby securing against unwanted modifications to data collection and/or load-control functionality. Security of the network and ensuring that customer data is protected at all times has resulted in the development of governance standards requiring extensive security measures such as NERC (North American Electric Reliability Corporation). The NERC reliability standards are developed by the electricity industry using a balanced, open, fair and inclusive process managed by the NERC Standards Committee.

For many Ontario LDCs, including RSL, completing a security audit at a NERC, NIST (Network Information Security & Technology) or comparable level would be a cost-prohibitive exercise. Therefore a consortium of Ontario Util-Assist LDC customers have worked together in the issuance of the November 2010 "Smart Meter Network Security Audit Services" Request for Proposal.

The objective of the RFP is to select an audit partner who would complete a security audit of the Elster Energy Axis AMI systems for consortium members withElster technology in place, and to the work with Elster towards the implementation of viable countermeasures to resolve all security concerns. The selected audit firm will first complete an in-depth security review at one participating utility that has the Elster solution. Once this review is complete, the audit firm would then review the technology at all remaining participating utilities to confirm that their Elster AMI systems are configured to the same standard as that declared as the standard for the group audit. Audits are anticipated to include end-to end from the meter to utility systems and home area network.

13.0 COPIES OF AGREEMENTS

The following agreements are confidential documents, and have not been filed with this Application:

- Advanced Metering Infrastructure Services Agreement between RSL and Elster Canadian Meter Company Inc.;
- Smart Meter Installation Agreement between RSL and Olameter Inc; and Operational Data Store Agreement between RSL and Kinetiq Inc.;
- RFP evaluations which include the pricing from each vendor.

RSL will provide additional information from these documents, on an as needed basis, subject to the Boards Rules of Confidentiality.

Elster Canadian Meter Company Inc., Olameter Inc. and Kinetiq Inc. are corporations which are engaged in competitive businesses. The disclosure of the terms of these agreements could reasonably be expected to prejudice the economic interests, competitive positions and cause undue financial interests of Elster Canadian Meter Company Inc., Kinetiq and Olameter respectively, since it would enable their competitors to ascertain the scope and pricing of services provided by these companies. The Board's Practice Direction on Confidential Filings (the "Practice Direction") recognizes that these are among the factors that the Board will take into consideration when addressing the confidentiality of filings. They are also addressed in section 17(1) of the Freedom of Information and Protection of Privacy Act ("FIPPA"), and the Practice Direction notes (at Appendix C of the Practice Direction) that third party information as described in subsection 17(1) of FIPPA is among the types of information previously assessed or maintained by the Board as confidential. Accordingly, RSL requests that these Agreements be kept confidential.

RSL is prepared to provide copies of the Agreements to parties' counsel and experts or consultants provided that they have executed the Board's form of Declaration and Undertaking with respect to confidentiality and that they comply with the Practice Direction, subject to RSL's right to object to the Board's acceptance of a Declaration and Undertaking from any person.

In keeping with the requirements of the Practice Direction, RSL is filing confidential unredacted versions of the Agreements under separate cover, in a sealed envelope marked "Confidential".

14.0 JUSTIFICATION FOR FUNCTIONALITY THAT EXCEEDS MINIMUM FUNCTIONALITY

The installed meters and systems do not exceed the minimum functionality as specified in O. Reg. 425/06, with the exception of 1.6.3 for web presentment, and for CIS modifications for TOU billing. The Capital Cost for the items exceeding the minimum functionality is $20,800.

15.0 COST INCURRED FOR FUNCTIONS WHICH SME HAS EXCLUSIVE AUTHORITY

There are no costs being sought for recovery, for items that are under the exclusive authority of the Smart meter Entity.

Cost Variance:

15.1 Capital Cost Analysis:

The Smart Meter total Capital Budget, as updated early in 2009, was $1,347,319 for the installation of 5,755 smart meters, and the supporting infrastructure.

The Actual Smart Meter Capital costs are $1,294,090 for 5,775 smart meters, and the supporting infrastructure.

The Capital Budget was developed from the London RFP process. By collaborating with the OUSM Group, by engaging a Project Manager (Util-Assist), and by assigning key personnel internally to the project, RSL was able to complete the Project on time, and under budget.

Capital costs by line item, compared to the Capital Budget, are provided below in Table 15.1

Table 15.1

Smart Meter Capital Costs

Smart Meter Installations		Actual Count	Budget Count
Actual/Planned number of Smart Meters installed during the Calendar Year			
Residential		5,005	4,980
General Service < 50 kW		770	775
Actual/Planned number of Smart Meters installed (Residential and GS < 50 kW only)		**5,775**	**5,755**
Percentage of Residential and GS < 50 kW Smart Meter Installations Completed		100.0%	
Smart Meter Capital Costs - Account 1555	**Asset Type**	**Capital Costs**	**Capital Budget**
1.1 ADVANCED METERING COMMUNICATION DEVICE (AMCD)	Asset type must be selected to enable		
1.1.1 Smart Meters *(may include new meters and modules, etc.)*	Smart Meter	$746,165	$737,436
1.1.2 Installation Costs *(may include socket kits, labour, vehicle, benefits, etc.)*	Smart Meter	$140,000	$123,692
1.1.3a Workforce Automation Hardware *(may include fieldwork handhelds, barcode hard*	Computer Hardware	$5,601	$5,939
1.1.3b Workforce Automation Software *(may include fieldwork handhelds, barcode hardw*	Computer Software	$3,344	$0
Total Advanced Metering Communications Devices (AMCD)		**$895,110**	**$867,067**
1.2 ADVANCED METERING REGIONAL COLLECTOR (AMRC) (includes LAN)	**Asset Type**		
1.2.1 Collectors	Smart Meter	$50,890	$60,494
1.2.2 Repeaters *(may include radio licence, etc.)*		$0	$0
1.2.3 Installation *(may include meter seals and rings, collector computer hardware, etc.)*		$0	$10,995
Total Advanced Metering Regional Collector (AMRC) (Includes LAN)		**$50,890**	**$71,490**
1.3 ADVANCED METERING CONTROL COMPUTER (AMCC)	**Asset Type**		
1.3.1 Computer Hardware	Computer Hardware	$15,567	$20,000
1.3.2 Computer Software	Computer Software	$82,373	$82,673
1.3.3 Computer Software Licences & Installation (includes hardware and software)		$0	$0
Total Advanced Metering Control Computer (AMCC)		**$97,940**	**$102,673**
1.4 WIDE AREA NETWORK (WAN)	**Asset Type**		
1.4.1 Activiation Fees	Computer Software	$33,754	$35,000
Total Wide Area Network (WAN)		**$33,754**	**$35,000**
1.5 OTHER AMI CAPITAL COSTS RELATED TO MINIMUM FUNCTIONALITY	**Asset Type**		
1.5.1 Customer Equipment *(including repair of damaged equipment)*		$0	$0
1.5.2 AMI Interface to CIS		$0	$11,146
1.5.3 Professional Fees	Smart Meter	$107,488	$121,380
1.5.4 Integration	Computer Software	$17,427	$29,070
1.5.5 Program Management	Smart Meter	$71,001	$64,638
1.5.6 Other AMI Capital	Smart Meter	-$320	$7,055
Total Other AMI Capital Costs Related to Minimum Functionality		**$195,597**	**$233,289**
Total Capital Costs Related to Minimum Functionality		**$1,273,290**	**$1,309,519**
1.6 CAPITAL COSTS BEYOND MINIMUM FUNCTIONALITY	**Asset Type**		
1.6.1 Technical capabilities that exceed those specified in O.Reg 425/06	Computer Software	$0	
1.6.2 Costs for other than residential and small general service cusotmers	Applications Software	$0	
1.6.3 TOU rate implementation, CIS system upgrades, web presentation,	Computer Software	$20,800	$37,800
Total Capital Costs Beyond Minimum Functionality		**$20,800**	**$37,800**
Total Smart Meter Capital Costs		**$1,294,090**	**$1,347,319**

15.2 Operations and Maintenance Cost Analysis:

The OM&A Budget for minimum functionality was set at $321,547, and covered deployment over a five year period – from 2008 to 2012.

RSL OM&A costs related to Minimum Functionality, for the Project to the end of 2012 Test year are $131,896.

RSL was one of the later organizations to start the Smart Meter Project. Time was spent at the front end by RSL Consultants, and by RSL investigating the requirements, and getting to know the products. As well, because RSL was later in the process, the systems were more stable, there was better documentations, and the process was went smoother. The net result was the project was able to be completed in a much shorter time frame, for substantially less cost. In addition, RSL has not charged any RSL staff labour to the Capital, or to the OM&A costs from the beginning in 2006, until December 31, 2011.

RSL spent 2009, 2010 and 2011 having the Smart Meters, the Collectors, and the Network installed.

RSL OM&A costs for the Smart meter Project, by line item, are shown below in Table 15.2

Table 15.2

Smart Meter Operations and Maintenance Costs (OM&A)

OM&A Expenses	To Date	Test	Total	Budget
2.1 ADVANCED METERING COMMUNICATION DEVICE (AMCD)	2011	2012	OM&A	OM&A
2.1.1 Maintenance *(may include meter reverification costs, etc.)*	$0	$904	$904	$0
2.1.2 Other *(please specifiy)*	$0	$0	$0	$0
Total Incremental AMCD OM&A Costs	$0	$904	$904	$0
2.2 ADVANCED METERING REGIONAL COLLECTOR (AMRC) (includes LAN)				
2.2.1 Maintenance	$97	$3,000	$3,097	$0
2.2.2 Other *(please specifiy)*	$0	$0	$0	$0
Total Incremental AMRC OM&A Costs	$97	$3,000	$3,097	$0
2.3 ADVANCED METERING CONTROL COMPUTER (AMCC)				
2.3.1 Hardware Maintenance *(may include server support, etc.)*	$0	$0	$0	$0
2.3.2 Software Maintenance *(may include maintenance support, etc.)*	$47,249	$13,478	$60,727	$76,251
2.3.2 Other *(please specifiy)*	$5,925	$0	$5,925	
Total Incremental AMCC OM&A Costs	$53,174	$13,478	$66,652	$76,251
2.4 WIDE AREA NETWORK (WAN)				
2.4.1 WAN Maintenance	$6,021	$3,000	$9,021	$18,711
2.4.2 Other *(please specifiy)*	$0	$0	$0	
Total Incremental AMRC OM&A Costs	$6,021	$3,000	$9,021	$18,711
2.5 OTHER AMI OM&A COSTS RELATED TO MINIMUM FUNCTIONALITY				
2.5.1 Business Process Redesign	$0	$0	$0	$0
2.5.2 Customer Communication (project communication, etc.)	$12,431	$0	$12,431	$26,105
2.5.3 Program Management	$0	$0	$0	$0
2.5.4 Change Management (may include training, etc.)	$1,980	$18,160	$20,140	$15,462
2.5.5 Administration Costs	$0	$11,561	$11,561	$64,930
2.5.6 Other AMI Expenses	$0	$8,090	$8,090	$90,720
2.0 Other - Utility Safety and Mtce, Unsafe Meter Base Repairs	$3,374			$29,368
Total Other AMI OM&A Costs Related to Minimum Functionality	$17,785	$37,811	$52,222	$226,585
TOTAL OM&A COSTS RELATED TO MINIMUM FUNCTIONALITY	$77,077	$58,193	$131,896	$321,547
2.6 OM&A COSTS RELATED TO BEYOND MINIMUM FUNCTIONALITY				
2.6.1 Costs related to technical capabilities in the smart meters or	$0	$0	$0	
2.6.2 Costs for deployment of smart meters to customers other than	$0	$0	$0	
2.6.3 Costs for TOU rate implementation, CIS system upgrades, web	$35,000	$24,280	$59,280	$88,893
Total OM&A Costs Beyond Minimum Functionality	$35,000	$24,280	$59,280	$88,893
Total Smart Meter OM&A Costs	$112,077	$82,473	$191,176	$410,440

15.3 Stranded Meter Costs:

RSL is seeking disposition of its stranded meter costs. RSL continues to recover these costs by including the net book value of stranded meters in its rate base until December 31, 2011, for rate-making purposes, as recommended by the Board in its Decision with Reasons in the Combined Proceeding. As of December 31, 2011, RSL had replaced 5,775 conventional meters with smart meters. The net book value of the stranded conventional meters at December 31, 2011 was $180,442.

Proceeds on the scrapped meters are captured in account 1555 as an offset to the costs in the deferral account, in accordance with the Board's Guideline 2011-0001 and the Board's December 15, 2011 letter to distributors on stranded meter costs related to the installation of smart meters, reproduced as Appendix B to the Guideline.

RSL has removed the Stranded Meter costs from rate base as of December 31, 2011, for RSL's 2012 COS Rate Application. There were no Capital additions to the Stranded Assets in 2011. Once the depreciation expense for 2011 was taken on the Stranded Meters, the NBV for Stranded Assets at December 31, 2011 is $180,441.57.

RSL's external Auditors conducted an Interim Audit on our actual Smart Meter Capital, OM&A costs in accounts 1555 and 1556 from January 1, 2011 until August 31, 2011, and the NBV of Stranded Assets. A copy of that Audit report is included as an attachment to this Exhibit. There are no other forecast changes or adjustments to the stranded meter costs for 2012.

Upon approval of the final rate order for 2012 COS, stranded asset costs will be transferred to 1555 "Sub-account Stranded Meter Costs" from account 1860, and the associated revenues collected from the separate stranded meter rate riders would be recorded in this sub-account to draw down the balance. No interest carrying charges will apply, until the effective date of the rate order. Once carrying charges are applied on the monthly opening principal balance, they will be recorded separately in the sub-account "1555 Approved Stranded Meter Costs Carrying Charges".

The Rate Rider is calculated by dividing the forecast 2011 NBV by the average number of metered accounts in the Test Year, by the one year recovery period.

The requested rate rider follows the Board Guidelines G-2011-0001 as updated December 15, 2011.

Table 15.3

Stranded Meter Costs

Year	Notes	Gross Asset Value	Accumulated Amortization	Contributed Capital (Net of Amortization)	Net Asset	Proceeds on Disposition	Residual Net Book Value
		(A)	(B)	(C)	(D) = (A) - (B) - (C)	(E)	(F) = (D) - (E)
2006		$ 272,799	$ 59,178		$ 213,621		$ 213,621
2007		$ 276,582	$ 70,165		$ 206,416		$ 206,416
2008		$ 276,582	$ 81,229		$ 195,353		$ 195,353
2009		$ 280,066	$ 92,362		$ 187,704		$ 187,704
2010		$ 295,772	$ 103,878		$ 191,893		$ 191,893
2011	(1)	$ 295,772	$ 115,330		$ 180,442		$ 180,442

Table 15.4
Customer Class Rate Rider

Stranded Meter Costs	Total Capital	Less	Stranded
	GL 1860	Industrial	Meters
Capital Cost	$431,826.37	-$136,054.86	$295,771.51
Accumulated Depreciation	$156,841.02	-$41,511.08	$115,329.94
Net Book Value	$274,985.35	-$94,543.78	$180,441.57
	Residential	Commercial	Total
Number of Customers - 2012	5,016	770	5,786
Stranded Assets - %	68.0%	32.0%	100.0%
Straned Assets - $	$122,763.21	$57,678.36	$180,441.57
Stranded Meter Rate Rider (SMRR)	**$2.04**	**$6.24**	

16.0 SMART METER DISPOSITION RATE RIDER (SMDR)

This rate rider will true-up the difference in the revenue requirement for smart meters installed from 2009 to 2011, less the amounts collected by the smart meter rate adder up to the end of April 30th 2012. The smart meter cost recovery rate rider is designed to recover a true-up value of $ 64,983.33 over a one year period.

The Smart Meter Disposition Rate Rider (SMDR) of $0.93 per metered customer per month for a one (1) year period commencing May 1, 2012, is to collect the net Deferred Revenue Requirement of $64,983.33. This rate rider is the true-up for the Smart Meter Projects costs incurred to December 31, 2011 ($499,649.82), less the forecast Revenues collected from 2006 until April 30th, 2012 ($434,666.49).

The Rate Rider Calculation is shown below in Table 16.0

Table 16.0

Smart Meter Disposition Rider (SMDR)

UPDATE WORKSHEET

	2006	2007	2008	2009	2010	2011	2012 and later	Total
Deferred and forecasted Smart Meter Incremental Revenue Requirement (from Sheet 5)	$ 499.11	$ 2,327.69	$ 4,743.68	$ 69,459.25	$ 158,688.91	$ 259,366.55	$ 264,063.00	$ 759,148.19
Interest on Deferred and forecasted OM&A and Amortization Expense (Sheet 8A/8B) (Check **one** of the boxes below)	$ 4.74	$ 34.77	$ 95.98	$ 257.74	$ 723.47	$ 3,447.92		$ 4,564.63
Sheet 8A (Interest calculated on monthly balances)								$ -
X Sheet 8B (Interest calculated on average annual balances)	$ 4.74	$ 34.77	$ 95.98	$ 257.74	$ 723.47	$ 3,447.92		$ 4,564.63
SMFA Revenues (from Sheet 8)	$ 10,468.80	$ 17,737.00	$ 17,837.48	$ 49,037.00	$ 107,462.40	$ 163,619.03	$ 58,381.52	$ 424,543.23
SMFA Interest (from Sheet 8)	$ 120.48	$ 883.85	$ 1,411.93	$ 622.62	$ 1,159.64	$ 4,023.26	$ 1,901.48	$ 10,123.26
Net Deferred Revenue Requirement	-$ 10,085.43	-$ 16,258.38	-$ 14,409.74	$ 20,057.36	$ 50,790.34	$ 95,172.18	$ 203,780.00	$ 329,046.33
Number of Metered Customers (average for 2012 test year)							5786	

Calculation of Smart Meter Disposition Rider (per metered customer per month)

Years for collection or refunding		1
Deferred Incremental Revenue Requirement from 2006 to December 31, 2011 plus Interest on OM&A and Amortization	$	499,649.82
SMFA Revenues collected from 2006 to 2012 test year (inclusive) Plus Simple Interest on SMFA Revenues	$	434,666.49
Net Deferred Revenue Requirement	$	64,983.33
SMDR May 1, 2012 to April 30, 2013	$	0.94
Check: Forecasted SMDR Revenues	$	65,266.08

Match

RSL proposes to recover the Smart Meter Disposition Rate Rider by customer class.

The average Smart Meter cost for a Residential customer was $92.32, and the average cost for a GS < 50 kW customer was $252.40.

Table 16.1

Smart Meter Actual Cost Recovery Rate Rider - SMDR Calculated by Rate Class			
	Total	Residential	GS < 50
Allocators			
LDC Average Smart Meter Unit Cost		$ 92.32	$ 252.40
Smart Meter Cost	$ 1,294,090	$ 982,520	$ 311,570
Allocation of Smart Meter Costs	100.0%	75.9%	24.1%
Number of meters installed	5,775	5,005	770
Allocation of Number of meters installed	100.0%	86.7%	13.3%
Total Return (deemed interest plus return on equity)	$ 165,408	$ 125,583	$ 39,824
Amortization	$ 220,715	$ 167,575	$ 53,140
OM&A	$ 108,703	$ 94,209	$ 14,494
Total Before PILs	$ 494,826	$ 387,368	$ 107,458
PILs	$ 4,824	$ 3,777	$ 1,048
Total Revenue Requirement 2006 to 2011	$ 499,650	$ 391,144	$ 108,506
	100.0%	78.3%	21.7%
Smart Meter Rate Adder Revenues	($424,543)		
Carrying Charge	($10,123)		
Smart Meter True-up	$ 64,983	$ 50,871	$ 14,112
Metered Customers	5,775	5,005	770
Recovery Period in Months	12	12	12
Rate Rider to Recover Smart Meter Costs 1 Yr	$ 0.94	$ 0.85	$ 1.53

The bill impact for Residential customers for 2012 is a net increase of $0.39. Proposed rates for Residential customers in 2012 are $2.04 for Stranded Assets plus $0.85 for the SMDR. In 2011 rates Residential customers were paying Smart meter Funding Adder of $2.50.

The bill impact for GS <50 kW customers for 2012 is a net increase of $5.27. Proposed rates for GS <50 kW customers in 2012 are $6.24 for Stranded Assets plus $1.53 for the SMDR. In 2011 rates GS <50 kW customers were paying Smart meter Funding Adder of $2.50.

17.0 CONCLUSION

Rideau St Lawrence Distribution Inc. respectfully submits that the costs necessary to fulfill its obligations under the provincially mandated Smart Meter initiative have been prudently incurred in accordance with Board guidelines; the proposed riders are just and reasonable, the associated customer bill impacts are minimal; and it is appropriate that the Board approve the proposed recovery riders for implementation effective May 1, 2012.

18.0 ADDENDUM

Addendum 1	Util Assist - CHEC Smart Meter Summary Report August 2011
Addendum 2	Attestation Letter of the Fairness Commissioner
Addendum 3	Meter Deployment RFP
Addendum 4	Operational Data Store RFP
Addendum 5	Wide Area Network RFP
Addendum 6	Audit Report on January to August 31, 2011 Actual costs.

util-assist

utility strategic operational assistance

Cornerstone Hydro Electric Concepts

August 15, 2011

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Executive Summary

In June of 2004, the Minister of Energy issued a Directive under Section 27.1 of the *Ontario Energy Board Act,* 1998 which required the Board to develop and, upon approval by the Minister of Energy, implement a plan to achieve the government's objectives for the deployment of smart electricity meters. In conjunction with the development of its implementation plan, the Directive also required the Board to examine the need for and effectiveness of time of use rates for non-commodity charges - in addition to season/time-based standard supply service commodity rates the Board is already in a position to establish - to complement the implementation of and maximize the benefits of smart meters.

The provincial Smart Meter Initiative would stem from this Directive and all Local Distribution Companies (LDCs) in Ontario would be heavily involved in creating a conservation culture in Ontario and making the Province a North American leader in energy efficiency. Key initiatives included the introduction of flexible, time-of-use pricing for electricity, and a targeted reduction in Ontario's energy consumption of 5%.

The provincial initiative mandated the installation of a smart electricity meter in every Ontario home by December 31, 2010, with the interim goal of 800,000 meters being deployed by December 31, 2007. The underlying premise behind the mandate to install these meters was to educate customers on their consumption habits and to implement new rate structures that encouraged load shifting and conservation of energy, thereby reducing the requirement for increased power generation capabilities.

This was an enormous undertaking for all LDCs; a project that took months of planning and carefully managed execution. To accommodate the needs of the Ministry of Energy and Infrastructure, CHEC members installed approximately 110,000 meters to fulfill their requirements for the mandate. Combined with the magnitude of the metering project, members also had the challenge of choosing technologies and installation service providers that could accommodate the stated requirements within their diverse LDC service territories.

Other Ontario Regulations that applied to the initiative include:

Reg. 425/06 Criteria and Requirements For Meters and Metering Equipment, Systems and Technology
Reg. 426/06 Smart Meter: Costs Recovery
Reg. 427/06 Smart Meters: Discretionary Metering Activity and Procurement Principles
Reg. 235/08 Amending Reg. 427/06 Smart Meters: Discretionary Metering Activity and Procurement Principles Functional Specification for an Advanced Metering Infrastructure – July 5, 2007

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Education and Preparation for the Initiative

As indicated above, the SMI required preparation and execution for the selection and deployment of new technology on an unprecedented scale. As this initiative was new to Ontario utilities, the CHEC group members recognized that there was much to be learned about the new AMI technologies to ensure that the operational efficiencies that become available through AMI would be realized as part of the initiative.

CHEC member utilities had achieved great success when working together on previous initiatives and elected for a collaborative approach to the education required for a successful Smart Meter Implementation. In so doing, utilities were involved with the Ontario Utility Smart Metering (OUSM) working group starting with its inception in March of 2005. Through this involvement, much was learned regarding prominent AMI systems and the technologies associated with back office integration of meter data, as well as the vendors associated with the installation of these products.

OUSM Working Group Participation

To satisfy the due diligence requirements of a project of this magnitude, an all-inclusive process was undertaken. In order to become educated on all aspects of the AMI initiative, CHEC members maintained involvement in the Ontario Utilities Smart Meter (OUSM), a working group that consisted of over 50 utility members that came together in an educational effort.

CHEC members supported the concept of the OUSM from the outset, embracing the collaborative approach to acquiring the required education for a successful Smart Meter Implementation. Through their involvement much was learned regarding all prominent AMI technologies available to the North American marketplace by:

1. Sharing information on the success of AMI pilots installed in utilities across the province

2. Reporting on the testing of different AMI technologies and components related to the AMI initiative which was completed in 2005.

    a. Standard Test Scripts were created and used for testing all AMI technologies, helping to provide comfort and back-up documentation to justify future vendor selection to a utility's board members and the OEB.

    b. The testing of products ensured an understanding not only of the functionality of the products *available* in this market, but also to understand the functionality that would be *required* of the different components of the Smart Meter system in order to accomplish the needs of the regulators. Acquiring insight into how different products delivered such components as time stamping of intervals, synchronization of register reads, network diagnostic components, etc, ensured that the chosen products could deliver the requirements of the regulators as well as accomplish the unique requirements of individual members.

c. The following AMI Systems were part of the testing completed by the OUSM and detailed reports are available on the Util-Assist Web Portal which provides test results and detailed information regarding functionality.

OUSM Tested AMI Systems

Elster	**Tantalus**	**EKA Systems**	**Trilliant**	**Cellnet**
Sensus	**Itron**	**SilverSpring**	**Quadlogic**	**SmartSynch**

By acting collaboratively with the OUSM, CHEC members were able to gain an understanding of the base functionality and advanced feature sets of these installed products, as well as the other prominent technologies available to the North American market.

CHEC Strategy

To cost-effectively plan for the deployment, and ensure due diligence was accommodated, CHEC members came together, and through a concerted effort, examined the benefits of a collaborative approach to planning, as well as procurement of AMI and Installation services. As part of this plan, the CHEC member utilities retained the services of Util-Assist Inc., an Ontario consulting firm who would provide guidance and direction to the group to assist in the preparation, deployment and back office integration for the SMI.

Satisfying CHEC's due diligence requirements entailed an all-encompassing process, accounting for:

1. Planning
2. Implementation
3. Testing, and
4. Complete Back Office Integration.

CHEC members worked together throughout the initiative, taking full advantage of the benefits that collaboration brings. The SMI project would touch every department in the utility and would touch every residential and small commercial customer in each LDC's service territory. All tasks had to be considered, from the selection and installation of the AMI infrastructure right down to the disposal of the redundant meters and ensuring that the recycling vendors were engaged so as to divert the meters from landfills. Benefits were found in on-going operational costs. By working together, the CHEC members drastically reduced the labour components associated with maintaining the health of the installed network, as well as the daily data collection requirements for the deployed system (i.e. 3 employees to maintain a CHEC AMI system vs. 13 employees to maintain an AMI system for each individual CHEC member).

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By collaborating with Util-Assist to develop an extensive plan, CHEC Members were sufficiently prepared to accommodate the established timelines. A project of this magnitude is not without risk and within this document we have identified the potential problems and risks which may impede progress (Rate Recovery, Meter Base Repairs, etc).

All aspects of the deployment were considered, including:

1. Rate recovery,
2. Regulatory requirements regarding AMI functionality
3. Strategic planning to minimize costs for deployment
4. Audit tools during deployment
5. Back office integration
6. Meter disposal
7. AMI security
8. WEB presentment
9. Sub-metering
10. Coordination with local municipalities
11. Change management and
12. most importantly, the continued dedication to Health and Safety;

Throughout the initiative, CHEC members stayed focused on mitigating associated risks, thereby ensuring the successful implementation of the Smart Meter Initiative.

Following is a brief timeline demonstrating the order of events that the CHEC group followed:

Timeline

1. 2007: Participation in Ministry of Energy and Infrastructure authorized London Hydro AMI RFP process (establishing best practice procurement procedures).
2. Q4 2008: release of ODS provider RFP (December 12, 2008)
3. Q4 2008: vendor submittal due date for responses to ODS RFP
4. Q4 2008: release of WAN provider RFP
5. Q1 2009: release of Meter Disposal RFQ
6. Q1 2009: vendor submittal due date for responses to WAN RFP (January 2, 2009)
7. Q4 2008: release of Installation Service Provider RFP
8. Q4 2008: vendor submittal due date for responses to RFP (November 21, 2008)
9. Q4 2008: evaluation of Installation vendor submittals
10. Q1 2009: vendor negotiation (secure best pricing, discuss associated risk)
11. Q1 2009: commence deployment of residential Smart Meters

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AMI Selection Process

As mass deployment rapidly approached, the strategy of the CHEC group was to work together and create a process that accomplished the goals of the Smart Meter Initiative, while controlling the risks to customers and share holders.

The phase one approved processes included the Coalition of Large Distributors (CLD) RFPQ in conjunction with the MOE and the Hydro One procurement process, through this process, 13 utilities would be authorized to move forward with the procurement and installation of smart meters.

The remaining LDCs in Ontario would be part of the consortium of utilities working together as part of the authorized London Hydro AMI RFP process (phase two) that is summarized below.

London Hydro Phase Two AMI RFP Process Summary

- A Request for Proposal procurement transaction was conducted by London Hydro Inc., as the lead sponsoring Local Distribution Company (LDC) and with a consortia of another 63 LDCs, during the period August 2007 to July, 2008;

- The evaluation and selection phase of the RFP provided for the determination of the #1 and #2 ranked Proponents for each LDC;

- RFP Provision 7.5.141 provides the framework (principle) for negotiations and contracting based on the principle of “first right to negotiation and execution of a contract” being accorded to the ranked order of Proponents commencing with the highest ranked Proponent and proceeding in a consecutive order thereafter; and

- Each LDC was provided the evaluation results for their #1 and #2 ranked Proponents supported by the Attestation Letter of the Fairness Commissioner as to those rankings.

From a final contract negotiation perspective the CHEC LDCs each initiated good faith contract negotiations with their identified “best value” bidder. There were cases with some CHEC members where these negotiations stalled or failed with the “best value” bidder (Silver Spring), and the second best value bidder was invited to negotiate a procurement contract. For some CHEC members the second vendor was Elster and for others, Sensus.

Ultimately the result for CHEC member utilities was that 50% of the group was awarded Elster’s Energy Axis AMI system and 50% was awarded Sensus’ FlexNet™ AMI system. This evaluation process was termed as phase two in the Ontario market place and was the method by which AMI systems were selected for the vast majority of utilities in the province.

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Following the selection of an AMI provider, attention was turned to the selection of an Installation Vendor and WAN provider (for those using the Elster AMI network).

Install Vendor Selection Process

CHEC's involvement in the London Hydro Phase Two Procurement Process proved to be of great value as the experience formed a foundation that ensured a sound and prudent procurement path was followed. An Installation Services RFP was created and five (5) vendors from across North America were invited to respond.

The invited vendors included Corix, Honeywell, Olameter, PowerQuest, (Keywell), and Trilliant, representing both vendors with local representation as well as vendors with extensive experience in larger markets. CHEC was confident that the most qualified and successful vendors were given the opportunity to submit proposals in response to the RFP.

CHEC's clearly stated requirement for the highest possible standards with regards to Safety were evident in every stage of the procurement process. The Request for Proposal identified CHEC's stringent Safety requirements, and included a requirement for bidder's to state their ability to either meet or exceed CHEC's guidelines. In addition to comprehensive Safety policies and procedures, CHEC's preference for a turnkey solution with the successful vendor performing all site related services and workforce management (i.e. customer communication, installation and commissioning, scheduling, dispatch and integration to back office systems, etc) was expressed.

In total, the operational considerations accounted for 40% of weighting of the evaluation with the remaining 60% attributed to the pricing received. The weighting structure was chosen to closely match that used in the 2006 CLD RFPQ process which had been found to be prudent by the regulator.

At the close of financial and technology evaluations, it was determined that Trilliant most closely matched all of CHEC's requirements; providing clear and concise Safety protocols as well as strong managerial tools to ensure all communicated policies and procedures would be properly implemented by the staff utilized within each CHEC member's service territory. These strong functional components were to be provided at a highly competitive price, which in combination resulted in the best service package being provided at the best price. Shortly after Trilliant was selected as the winning proponent, the group received notice that Olameter had acquired Trilliant and thus Olameter would be providing the services to the group.

As many utilities had a relationship with Olameter for meter reading services and Olameter was quite active in the Ontario market, this worked in the group's favour. Olameter's operational score in the RFP evaluation was strong; however their pricing was not the most favourable which attributed to their ranking as number three in the evaluation model. Given the success being enjoyed by Olameter within Ontario, there was confidence that there was minimal risk in the decision to award Olameter with the installation of CHEC's residential Smart Meters.

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ODS Vendor Selection Process

CHEC member utilities recognized early on that an Operational Data Store (ODS) would be of value to support their needs for the introduction of efficiencies which would become possible through the use of the operational data available from the AMI system as the MDM/R didn't store operational data.

According to the Ministry of Energy's Functional Specification, the Advanced Metering Control Computer (AMCC – AMI network server) is limited to a maximum of 60 days for the storage of AMI data. Whereas ODS systems act as a repository to store unlimited data and have the architecture with the mechanisms in place to retain and archive data for analysis by the utility.

Many benefits can be realized through the use of an ODS system, one of which is to use the ODS to audit the mass meter installation to prevent the situation of deploying the AMI network "blind". The AMI systems traditionally will indicate that the meters are communicating but the ODS will verify the quality of the data coming from the AMI system.

Other examples of the available functionality in ODS systems include verification of all data fields being transmitted from AMI, such as:

- Readings (kWh, kW)
- Alarm Filtering (Tamper, Outage)
- Power Quality Data (Voltage)
- Perform Data Gap Analysis
- SLA management of AMI system

Due to the possibility that the provincial centralized Meter Data Management and Repository (MDM/R) would one day accommodate operational needs in addition to the billing requirements, and in keeping with the desire to minimize duplication in utility infrastructure, the utilities chose to procure a system that was an Application Service Provider (ASP) model, allowing the system to grow with the needs of each utility, and also provide flexibility with regards to contract term.

To be prepared for the deployment of residential smart meters in each utility's service territory, the ODS RFP was developed focusing on data management functionality which would definitively determine a utility's compliance with the requirements of the Ministry of Energy's Functional Specification. Additionally, the ODS system would be required to store operational data which will allow utilities to implement operational efficiencies in the immediate future.

The ODS Request for Proposal (RFP) was distributed to selected vendors in North America with fourteen (14) vendors invited to respond. These vendors included local representation as well as vendors with extensive experience in larger markets. CHEC was confident that the most qualified and successful vendors were given the opportunity to submit proposals in response to the RFP.

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The evaluation team consisted of representatives from four utilities in the CHEC group with resources from Centre Wellington Hydro Ltd., Innisfil Hydro Distribution Systems Limited, Lakeland Power Distribution Ltd. and Wellington North Power Inc. volunteering to be part of the committee. This committee provided for a mixture of Elster and Sensus AMI users and a wealth of both technical and operational knowledge.

The evaluation criteria and scoring documents were prepared in advance of the release of the RFP to support a prudent process and identify scoring criteria that ensured a consistent and fair approach in the evaluation of the bids. Many of the ODS systems were considered new technology and to ensure that the written responses and functionality descriptions in the RFP matched the state of the actual technology released, vendor demonstrations were held allowing utilities the opportunity to see the actual software.

The team evaluated Bidders objectively with the end goal of selecting the best-fit service provider for an ODS solution, thereby allowing utilities to achieve their internal goals of maximizing the value from the assets in the field, while ensuring that the requirements of the provincial government are met. With financial and technology evaluations completed, it was determined that the Kinetiq ODS proposal most closely matched all of the requirements; providing strong support for the functionality requirements expressed through the RFP, as well as project management support tailored to the needs of each utility to ensure project success.

Given the experience of Kinetiq with Ontario utilities, there was confidence that there was minimal risk in the decision to award Kinetiq with the ODS component of their Smart Meter Network infrastructure. After further discussion amongst the member utilities and a review of the evaluation documents, vendors were notified of the award of the bid and Kinetiq was engaged to move forward with the contract negotiations process.

Supplied documentation reflects the analysis that went into this important decision by noting the functionality provided by the bidders as well as the pricing and associated risk of the different vendors. The decision making process regarding ODS solutions has been well documented and conclusive, to provide each utility's Executive Management team with the confidence to support the decision made by the committee. The well organized approach has ensured that the proper decisions have been made and documented with the end goal of achieving all SMI related timelines.

WAN Vendor Selection Process

CHEC members utilizing the Elster Energy Axis AMI network would be required to select a Wide Area Network (WAN) vendor to provide the communications backhaul for their AMI networks. CHEC members moved forward initiating a process for the procurement of a WAN solution in Q4 of 2008. The WAN RFP was designed with the intention of procuring a solution which would allow increased flexibility and functionality in the long term. The RFP development process included flexibility, allowing vendors to provide solutions of a wired and/or wireless nature, satisfying immediate requirements with options to expand the proposed solution, as well as ancillary services to allow savings through potential synergies. As part of the procurement process the components of service that were required were:

1. Hardware Procurement
2. Installation and Commissioning
3. Ongoing Maintenance

During every stage of the procurement process it was CHEC member's clearly stated objective that the selected WAN solution would provide a method to enable the AMI to meet the Ministry of Energy and Infrastructure's Functional Specification for the timely delivery and reliable transmission of meter data. The WAN RFP "weighting" followed a format that was found to be prudent by the regulator; in total, the operational considerations would account for 40% of the evaluation, with the remaining 60% attributed to the pricing received.

The RFP was released by CHEC on December 5, 2008 and a decision was made to select Bell/National Wireless as the provider in Q1 of 2009.

MDM/R Integration Process Project planning

Ontario Regulation 393/07: Designation of Smart Metering Entity would authorize the Independent Electricity System Operator (IESO) as the Smart Metering Entity responsible for processing all meter read interval data to provide billing quantity data to all LDCs in Ontario. This centralized system is termed as the Provincial Centralized MDM/R (MDM/R).

Having made such tremendous progress in the acquisition and implementation of systems, CHEC recognized the value in collaboration and continued to work together with Util-Assist to complete the necessary steps required to integrate their systems into the MDM/R.

As part of this strategy, Util-Assist developed and presented a series of MDM/R Education Sessions in which the CHEC members were educated about the MDM/R and the Business Process changes that would be required to effectively integrate and interact with the MDM/R on an enduring basis.

Standard processes were provided to members allowing them to tailor the processes for their own situations. Several members elected to have Util-Assist provide a more in-depth analysis of their processes and ultimately assist the LDCs in the design and development of specific processes unique to their utility.

Successfully integrating to the MDM/R would require months of education to prepare for the formalized enrolment testing run by the IESO. Dedicated resources would be required from each utility to be the test lead and engage with the IESO during the 8 week enrolment timeframe leading up to the cutover to the MDM/R (flowing all meter data). The flowing of all residential and small commercial customers'

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meter data to the MDM/R would be required in order for utilities to successfully implement the new time-of-use rate structures.

On June 24, 2010, the Board issued for comment a Proposed Determination (the "June Proposed Determination") to mandate time-of-use ("TOU") pricing for RPP consumers by establishing the "mandatory TOU date" for each electricity distributor as contemplated in section 1.2.1 of the Standard Supply Service Code (the "SSS Code"). In the June Proposed Determination, the Board proposed that a distributor's mandatory TOU date will be one of two dates, depending on the distributor's progress to date against the schedule set out in its baseline plan (updated to the date of the June Proposed Determination, where applicable).

This would require the CHEC member utilities to implement time-of-use rates in their service territory based on the dates provided in the OEB determination. As of the writing of this report, approximately 30% of the CHEC member utilities have implemented time-of-use pricing in their service territories while all other members are on a path to successfully fulfill their requirements to the regulator.

Conclusion

The CHEC group members are confident that a comprehensive process has been undertaken and successfully completed, and that the due diligence requirements for all decisions related to this initiative have been satisfied.

Through the process of working together with other LDCs, CHEC has realized the true value of collaboration, having received support as well as operational and pricing efficiencies that were not possible had each LDC gone through the process on their own.

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Appendix A

a) Ontario Regulation 425/06
b) Functional Specifications document

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ONTARIO REGULATION 425/06

made under the

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CRITERIA AND REQUIREMENTS FOR METERS AND METERING EQUIPMENT, SYSTEMS AND TECHNOLOGY

Adoption of criteria and requirements

1. For residential and small general service consumers, the prescribed criteria and requirements for meters, metering equipment, systems and technology and any associated equipment, systems and technologies are the criteria and requirements specified in the document entitled "Functional Specification for Advanced Metering Infrastructure" dated July 14, 2006 and available at the Ministry of Energy, 4th Floor, Hearst Block, 900 Bay Street, Toronto, Ontario or at http://www.energy.gov.on.ca/english/pdf/electricity/smartmeters/Functional_Specification_for_Advanced_Metering_Infrastructure.pdf.

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FUNCTIONAL SPECIFICATION

FOR AN

ADVANCED METERING INFRASTRUCTURE

JULY 14, 2006

FUNCTIONAL SPECIFICATION

FOR AN ADVANCED METERING INFRASTRUCTURE

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FUNCTIONAL SPECIFICATION

FOR AN ADVANCED METERING INFRASTRUCTURE

1.0 APPLICATION OF SPECIFICATION

This Specification sets the required minimum level of functionality for AMI in the Province of Ontario for residential and small general service consumers where the metering of demand is not required. This Specification is not intended to apply to net metering applications.

2.0 FUNCTIONAL SPECIFICATION

2.1 Deployment

This Specification shall be met regardless of the size or scope of the AMI deployment by a distributor.

2.2 Minimum Functionality

2.2.1 As a minimum:

2.2.1.1 AMI shall collect Meter Reads on an hourly basis from all AMCDs deployed by a distributor and transmit these same Meter Reads to the AMCC and MDM/R, as required, in accordance with these Specifications; and

2.2.1.2 A Meter Read shall be collected, dated and time stamped at the end of each hour (i.e. midnight as represented by 24:00).

2.2.2 The date and time stamping of Meter Reads shall be recorded as year, month, day, hour, minute (i.e. YYYY-MM-DD hh:mm).

2.2.3 All meters shall have a meter multiplier of one (1).

2.2.4 Distributors shall provide the MDM/R with the service multiplier for transformer-type meters.

2.3 Performance Requirements

2.3.1 Collection and Transmission of Meter Reads:

2.3.1.1 AMI shall successfully collect and transmit to the AMCC and MDM/R at least 98.0% of the Meter Reads from all AMCDs deployed by a distributor in any Daily Read Period.

2.3.1.2 Meter Reads unsuccessfully collected or transmitted shall not be due to the same AMI component (including, without limitation, any AMCD) during any three (3) month consecutive time period.

2.3.1.3 AMI shall be able to collect and transmit Meter Reads during its operating life without requiring a field visit.

2.3.2 Transmission Accuracy: Over the Daily Read Period, 99.9% of the Meter Reads received by the AMCC shall contain the same information as that collected by all AMCDs deployed by the distributor.

2.3.3 AMI shall be capable of providing Meter Reads with a precision of at least 10 Watt-hours (0.01 kWh).

2.4 Technical Requirements

2.4.1 When an AMI includes AMRCs, the AMRCs shall have the ability to store meter data to accommodate the performance requirements in section 2.3.1.

2.4.2 Time Synchronization:

2.4.2.1 AMI shall be operated and synchronized to Official Time, as set by the National Research Council of Canada.

2.4.2.2 AMI shall have the capability of adjusting for changes due to local daylight savings time.

2.4.2.3 AMI installed within a distributor's service area shall have the capability of accommodating more than one (1) time zone.

2.4.2.4 Time synchronization shall be maintained in the AMI to the specified accuracy parameters set out in section 2.4.3.1 following a loss of power.

2.4.2.5 All Meter Reads shall adhere to accurate time synchronization processes to ensure an accurate accounting of electricity consumption at each meter.

2.4.3 Time Accuracy:

2.4.3.1 At all times, time accuracy in the AMI shall not exceed a ±1.5 minute variance from the time established in section 2.4.2.1.

2.4.3.2 AMI shall be able to prove that time accuracy does not exceed the permitted time variance identified in section 2.4.3.1.

2.4.4 Loss and Restoration of Power:

2.4.4.1 AMI shall detect and identify the interval in which a loss of power occurred during a Daily Read Period.

2.4.4.2 AMI shall detect and identify the interval in which power was restored following a loss of power.

2.4.5 Environmental Tolerances: All AMI components (except the AMCC) shall operate and meet the requirements in these Specifications within a temperature range of minus thirty degrees Celsius (–30° C) to positive sixty-five degrees Celsius (+65° C), and within a humidity range of zero percent (0%) to ninety-five percent (95%) non-condensing.

2.5 Advanced Metering Communication Device (AMCD)

2.5.1 Installation Within the Meter:

2.5.1.1 The AMCD shall not impair the ability of the meter to be visually read.

2.5.1.2 Meters in which an AMCD is installed shall be able to be installed in existing meter sockets or enclosures.

2.5.1.3 AMCD shall meet or exceed ANSI standards to withstand electrical surges and transients.

2.5.2 Labelling:

2.5.2.1 The AMCD shall be permanently labelled with:

(1) Legally required labelling;

(2) Manufacturer's name;

(3) Model number;

(4) AMCD identification number;

(5) Input/output connections;

(6) Date of manufacture; and

(7) Bar code for tracking and inventory management.

2.5.3 When installed at a consumer's location, the meter shall visibly display, as a minimum, the AMCD identification number, meter serial number and LDC badge number for the meter.

2.5.4 The AMCD shall be able to be initialized or programmed during, or prior to, field installation.

2.6 Transmission of Meter Reads

2.6.1 All Meter Reads collected during the Daily Read Period shall be received by the AMCC and transferred to the MDM/R no later than 5:00 a.m. local time following the Daily Read Period.

2.6.2 Meter Reads are not required to be transmitted in a single transmission and may be transmitted as frequently as necessary in order to meet the requirements in section 2.6.1.

2.6.3 AMCC shall transfer the information identified in section 2.6.1 using an approved protocol and file structure.

2.7 Advanced Metering Regional Collectors (AMRC)

2.7.1 LAN Communication Infrastructure:

2.7.1.1 The spectrum allocation and wattage of the radio signal used by an AMI shall not impede neighbouring frequencies.

2.7.2 When an AMI includes AMRCs:

2.7.2.1 The AMI shall provide for the continuous powering of AMRCs regardless of their location and placement.

2.7.2.2 All AMCDs shall be able to collect and transmit Meter Reads when one or more AMRC has a loss of power.

2.7.2.3 Memory and software parameters shall be maintained at all AMRC during a loss of power, whether by the provision of backup/alternate power or other solution.

2.8 Advanced Metering Control Computer (AMCC)

2.8.1 Each AMCC shall have the ability to store a rolling sixty (60) days of Meter Reads.

2.8.2 A distributor shall not aggregate Meter Reads into rate periods or calculate consumption data from the Meter Reads collected through its AMI either in its AMCC or any other component.

2.8.3 The AMCC shall be able to perform basic operational verification of Meter Reads received before transmitting these Meter Reads to the MDM/R.

2.9 Customer Account Information

2.9.1 Distributors shall provide initial information associated with customer accounts to the MDM/R on a date to be determined.

2.9.2 On an ongoing basis, distributors shall provide information associated with any change to the initial information identified in section 2.9.1 to the MDM/R at a frequency to be determined.

2.9.3 Information to be provided to the MDM//R pursuant to sections 2.9.1 and 2.9.2 is to be determined.

2.10 Monitoring & Reporting Capability

2.10.1 The AMI shall have non-critical reporting functionality and critical reporting functionality as required in this section 2.10. Information generated from this reporting functionality shall be available to the MDM/R.

2.10.2 Non-critical reporting:

2.10.2.1 At the completion of every Daily Read Period and following a transmission of Meter Reads, the AMCC shall generate a status report that includes information regarding anomalies and issues affecting the integrity of the AMI or any component of the AMI including information related to any foreseeable impact that such anomalies or issues might have on the AMI's ability to collect and transmit Meter Reads.

2.10.2.2 In addition to section 2.10.2.1, the AMCC shall generate reports:

(1) Confirming successful initialization of the AMCD's installed in the field;

(2) Confirming data linkages among an AMCD identification number, LDC badge number, serial number and customer account;

(3) Confirming that the MDM/R has successfully received notification of any changes to customer account information;

(4) Confirming that the AMCC has successfully made changes to customer account information following receipt of same from the MDM/R;

(5) Confirming the successful collection and transmission of Meter Reads or logging all unsuccessful attempts to collect and transmit Meter Reads, identifying the cause, and indicating the status of the unsuccessful attempt(s) pursuant to section 2.3.1;

(6) Confirming the accuracy of the Meter Reads received by the AMCC pursuant to section 2.3.2;

(7) Confirming that all Meter Reads have a precision of at least 10 Watt-hours (0.01 kWh) pursuant to section 2.3.3;

(8) Confirming whether the Meter Reads acquired within the Daily Read Period are in compliance with the time accuracy levels identified in section 2.4.3;

(9) Confirming whether time synchronization within the AMI or any components of the AMI has been reset within the Daily Read Period;

(10) Identifying the intervals in which a loss of power occurred and at which power was restored, following a loss of power;

(11) Addressing the functionality of the AMCD communication link, including status indicators related to the AMCD and AMRC;

(12) Identifying suspected instances of tampering, interference and theft;

(13) Flagging potential network, meter and AMCD issues; and

(14) Identifying any other instances that impact or could potentially impact the AMI's ability to collect and transmit Meter Reads to the AMCC and/or MDM/R on a daily basis.

2.10.2.3 Following a transmission of Meter Reads or at the completion of every Daily Read Period, the information in section 2.10.2.2 (5) shall be stored and used by the AMCC to assess compliance with the requirement specified in section 2.3.1.2.

2.10.2.4 The reports generated in sections 2.10.2.1 and 2.10.2.2 shall be made available to the MDM/R with a frequency to be determined.

2.10.3 Critical reporting:

Critical events are defined to include any AMI operational issue that could adversely impact the collection and transmission of Meter Reads during any Daily Read Period.

2.10.3.1 The AMI shall identify and report the following to the distributor:

(1) AMCD failures;

(2) AMRC failures;

(3) Issues related to the storage capacity of any component of the AMI;

(4) Communication links failures;

(5) Network failures; and

(6) Loss of power and restoration of power.

2.10.3.2 The reports generated in section 2.10.3.1 shall be made available to the MDM/R.

2.11 Security and Authentication:

2.11.1 The AMI shall have security features to prevent unauthorized access to the AMI and meter data and to ensure authentication to all AMI elements.

2.12 Proven Technology

2.12.1 No distributor shall install more than five hundred (500) units of a particular model of electricity AMCD if a minimum of five thousand (5,000) units of the same model of electricity AMCD that is to be installed by the distributor is not currently functioning in the field as part of one or more functioning AMI.

2.13 Regulatory Requirements

2.13.1 The AMI shall meet all applicable federal, provincial and municipal laws, codes, rules, directions, guidelines, regulations and statutes (including any requirements of any applicable regulatory authority, agency, board, or department including Industry Canada, the Canadian Standards Association, the Ontario Energy Board and the Electrical Safety Authority) (collectively, "**Laws**"). For greater certainty, the AMI shall meet all applicable Laws that are necessary for the measurement of data and/or the transmission of data to and from the consumers within the Province of Ontario, including Laws applicable to metering, safety and telecommunications.

2.14 Water or Natural Gas Meter Reads

2.14.1 The AMI should be capable of supporting an increased number of Meter Reads associated with the reading and transmission of water and/or natural gas meters through additional ports on the AMCD, through optionally available multi-port AMCDs, or through additional AMCD/AMRC devices that are compatible with operating on the AMI. When procuring AMI, distributors shall obtain an indication of the capabilities of the proposed AMI to read water and natural gas meters, indicating the makes and models of such meters that can be read, and any requirements for retrofitting them.

3.0 DEFINITIONS

Within this Specification the following words and phrases have the following meanings:

"AMCC" is an advanced metering control computer that is used to retrieve or receive and temporarily store Meter Reads before or as they are being transmitted to the MDM/R. The information stored in the AMCC is available to log maintenance and transmission faults and issue reports on the overall health of the AMI to the distributor.

"AMCD" is an advanced metering communication device that is housed either under the meter's glass or outside the meter. It transmits Meter Reads from the meter directly or indirectly to the AMCC.

"AMI" means an advanced metering infrastructure. It includes the meter, AMCD, LAN, AMRC, AMCC, WAN and related hardware, software and connectivity required for a fully functioning system that complies with this Specification. With some technologies, an AMI does not include AMRCs. An AMI does not include the MDM/R.

"AMRC" is an advanced metering regional collector that collects Meter Reads over the LAN from the AMCD and transmits these Meter Reads to the AMCC.

"consumer" or "customer" means a person who uses, for the person's own consumption, electricity that the person did not generate.

"distributor" has the meaning provided in the *Ontario Energy Board Act, 1998*.

"Daily Read Period" means the 24-hour period for collecting Meter Reads, subject to the two periods annually during which changes to and from daylight savings time take place. The Daily Read Period ends at 12:00 midnight of each day.

“LAN” means a local area network, the communication network that transmits Meter Reads from the AMCD to the AMRC.

“meter multiplier” is the factor by which the register reading must be multiplied to obtain the registration in the stated units.

“Meter Read” is a number generated by a meter that reflects cumulative electricity consumption at a specific point in time.

“MDM/R” means the meter data management and meter data repository functions within which Meter Reads are processed to produce rate-ready data and are stored for future use.

“Specification” means these functional specifications.

“transformer-type meter” means a meter designed to be used with instrument transformers.

“WAN” means a wide area network, the communication network that transmits Meter Reads from the AMRC to the AMCC or, in some systems from the AMCD directly to the AMCC, and from the AMCC to the MDM/R.

Appendix B

a) Ontario Regulation 426/06

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Ontario

ServiceOntario
e-Laws

Ontario Energy Board Act, 1998
Loi de 1998 sur la commission de l'énergie de l'Ontario

ONTARIO REGULATION 426/06

SMART METERS: COST RECOVERY

Consolidation Period: From June 25, 2008 to the e-Laws currency date.

Last amendment: O. Reg. 234/08.

This Regulation is made in English only.

Cost recovery, general

1. (1) In relation to the acquisition of smart meters, a distributor may recover its costs relating to functionality that does not exceed the minimum functionality adopted in Ontario Regulation 425/06 (Criteria and Requirements for Meters and Metering Equipment, Systems and Technology) made under the *Electricity Act, 1998,* subject to final approval by the Board and the Board's review and determination that the agreement entered into for the acquisition is economically prudent and cost effective. O. Reg. 234/08, s. 1 (1).

(1.01) In determining whether an agreement referred to in subsection (1) is economically prudent and cost effective, the Board's review shall take into consideration, but not be limited to,

(a) all costs associated with the agreement; and

(b) the costs of the agreement relative to any agreements entered into by the distributor and other distributors for comparable acquisitions. O. Reg. 234/08, s. 1 (1).

(1.1) Subject to final approval of the Board, a distributor may recover the costs it prudently incurred to comply with the enrolment requirements and technical interface requirements of the Smart Metering Entity. O. Reg. 441/07, s. 1; O. Reg. 234/08, s. 1 (2).

(2) In relation to the acquisition of smart meters, a distributor may not recover its costs relating to functionality that exceeds the minimum functionality adopted in Ontario Regulation 425/06 (Criteria and Requirements for Meters and Metering Equipment, Systems and Technology) made under the *Electricity Act, 1998* unless the costs are approved by the Board. O. Reg. 426/06, s. 1 (2); O. Reg. 234/08, s. 1 (3).

(3) In reaching a decision under subsection (2), the Board may consider the matters that it considers appropriate, including evidence that the functionality that exceeds the minimum functionality adopted in Ontario Regulation 425/06 (Criteria and Requirements for Meters and Metering Equipment, Systems and Technology) made under the *Electricity Act, 1998* benefits the distributor's consumers. O. Reg. 426/06, s. 1 (3).

(4) In this section,

"smart meters" includes smart meters, metering equipment, systems and technology and any associated equipment, systems and technologies. O. Reg. 234/08, s. 1 (4).

Cost recovery, meter data functions

2. (1) No distributor shall recover any costs associated with meter data functions to be performed by the Smart Metering Entity. O. Reg. 426/06, s. 2 (1).

(2) Despite subsection (1), distributors may recover costs associated with functions related to meter data that are contemplated to be performed by distributors by the criteria and requirements adopted in Ontario Regulation 425/06 (Criteria and Requirements for Meters and Metering Equipment, Systems and Technology) made under the *Electricity Act, 1998*. O. Reg. 426/06, s. 2 (2).

(3) Subsection (1) does not prevent distributors from recovering costs that are approved by the Board pursuant to section 1 that are associated with functions related to meter data that relate to a distributor's operation of its distribution system, but only if those functions are not meter data functions to be performed by the Smart Metering Entity. O. Reg. 426/06, s. 2 (3).

(4) Subsection (1) does not apply to distributors with service areas identified as priority installations in Ontario Regulation 428/06 (Priority Installations) made under the *Electricity Act, 1998*. O. Reg. 426/06, s. 2 (4).

(4.1) Subsection (1) does not prevent a distributor from recovering costs, if approved by the Board, that the distributor incurred as a result of supporting the IESO with finalizing the design of the requirements and processes for the interface and integration of the Smart Metering Entity's system with the distributor's billing and metering systems. O. Reg. 392/07, s. 1.

(4.2) The distributor's cost recovery under subsection (4.1) is subject to the Board receiving confirmation from the IESO that the distributor supported the IESO as described in subsection (4.1) and that the distributor was one of the first five distributors whose billing and metering systems were integrated with the Smart Metering Entity's system. O. Reg. 392/07, s. 1.

(5) In this section,

"meter data functions" means those functions for which the Smart Metering Entity has the exclusive authority to carry out pursuant to Ontario Regulation 393/07 (Smart Metering Entity) made under the *Electricity Act, 1998*. O. Reg. 426/06, s. 2 (5); O. Reg. 234/08, s. 2.

Cost recovery, replaced meter assets

3. (1) Subject to Board order, to ensure that distributors are not financially disadvantaged by the implementation of the smart metering initiative, distributors may recover the costs associated with meters owned before, on or after January 1, 2006 being replaced because of the smart metering initiative if,

(a) the meter being replaced was not acquired in contravention of section 53.18 of the *Electricity Act, 1998*; and

(b) the meter is replaced with a smart meter authorized for installation under the *Electricity Act, 1998*. O. Reg. 441/07, s. 2.

(2) The Board shall determine the period of time over which the costs referred to in subsection (1) may be recovered, in order to protect the interests of consumers with respect

to prices. O. Reg. 441/07, s. 2.

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Appendix C

a) Ontario Regulation 427/06
b) Ontario Regulation 235/08

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Electricity Act, 1998
Loi de 1998 sur l'électricité

ONTARIO REGULATION 427/06

SMART METERS: DISCRETIONARY METERING ACTIVITY AND PROCUREMENT PRINCIPLES

Consolidation Period: From June 25, 2008 to the e-Laws currency date.

Last amendment: O. Reg. 235/08.

This Regulation is made in English only.

Definition

0.1 In this Regulation,

"smart meters" includes smart meters, metering equipment, systems and technology and any associated equipment, systems and technologies. O. Reg. 235/08, s. 1.

Authorized discretionary metering activity

1. (1) The following activities are authorized discretionary metering activities for the purposes of section 53.18 of the Act:

1. Metering activities conducted pursuant to the distributor's Conservation and Demand Management Plan approved by a Board order referenced as RP - 2004 - 0203, including pursuant to a reallocation of funds within an approved Conservation and Demand Management Plan as authorized by the Board order approving the Conservation and Demand Management Plan or that is otherwise approved by the Board.

2. If not otherwise authorized by this subsection, a distributor may utilize funds to conduct metering activities that are for the purpose of testing smart meter technology if,

    i. the distributor has the prior approval of the Board, and

    ii. the funds that are utilized were collected pursuant to the Board's approval to include capital and operating costs related to smart meters in distributors' revenue requirements for 2006, as set out in the Board's Generic Issues decision, dated March 21, 2006 and referenced as RP - 2005 - 0020, as is incorporated into each distributor's 2006 electricity distribution rate order provided by the Board pursuant to section 78 of the *Ontario Energy Board Act, 1998*.

3. Metering activities conducted by Enersource Corporation, Powerstream Inc., Hydro Ottawa Limited, Horizon Utilities Corporation, Toronto Hydro-Electric System

Limited and Veridian Connections Inc. pursuant to the process initiated in the Request for Pre-Qualification for Advanced Metering Infrastructure Procurement and Installation issued by Enersource Corporation on behalf of itself and the other referenced utilities and dated May 2, 2006.

3.1 Metering activities conducted by a distributor listed in paragraph 3, if the smart meters were procured subsequent to the process referred to in paragraph 3.

4. Metering activities conducted by a distributor that has had its smart meters procured on its behalf by one or more of Enersource Corporation, Powerstream Inc., Hydro Ottawa Limited, Horizon Utilities Corporation, Toronto Hydro-Electric System Limited or Veridian Connections Inc. pursuant to the process referred to in paragraph 3.

5. Metering activities conducted pursuant to the Request for Proposal for Smart Metering Services issued by Hydro One Networks Inc. and dated March 4, 2005.

6. Metering activities conducted by a distributor that has had its smart meters procured on its behalf by Hydro One Networks Inc. pursuant to the process referred to in paragraph 5.

7. Metering activities conducted by distributors if the activities meet the following criteria:

   i. the activities are for service areas identified as priority installations by Ontario Regulation 428/06 (Priority Installations) made under the Act, and

   ii. smart meter deployment plans have been filed with the Minister by the distributor.

8. Metering activities conducted by a distributor that has procured its smart meters pursuant to and in compliance with the parameters and process established by the Request for Proposal for Advanced Metering Infrastructure (AMI) – Phase 1 Smartmeter Deployment dated August 14, 2007, together with any amendments to it, issued by London Hydro Inc. O. Reg. 427/06, s. 1 (1); O. Reg. 153/07, s. 1 (1); O. Reg. 235/08, s. 2 (1-4).

(2) The smart meters used in relation to activities authorized as discretionary metering activities in subsection (1) shall comply with the criteria and requirements adopted in Ontario Regulation 425/06 (Criteria and Requirements for Meters and Metering Equipment, Systems and Technology) made under the Act. O. Reg. 427/06, s. 1 (2); O. Reg. 153/07, s. 1 (2); O. Reg. 235/08, s. 2 (5).

(2.1) Despite subsection (2), the smart meters used in relation to activities authorized as discretionary metering activities in paragraph 1 of subsection (1) that were conducted before the day this subsection comes into force are not required to comply with the criteria and requirements adopted in Ontario Regulation 425/06 (Criteria and Requirements for Meters and Metering Equipment, Systems and Technology) made under the Act. O. Reg. 153/07, s. 1 (3); O. Reg. 235/08, s. 2 (6).

(3) Any procurement associated with the activities authorized as discretionary metering activities under subsection (1), other than activities referenced in paragraphs 1 and 2 of subsection (1), shall comply with the procurement requirements set out in section 2. O. Reg. 427/06, s. 1 (3); O. Reg. 153/07, s. 1 (4).

(4) The activities authorized as discretionary metering activities in subsection (1) are subject to the cost recovery requirements set out in Ontario Regulation 426/06 (Smart

Meters: Cost Recovery) made under the *Ontario Energy Board Act, 1998*. O. Reg. 427/06, s. 1 (4).

Procurement

2. (1) When a distributor enters into a procurement process in relation to the smart metering initiative, the distributor shall ensure,

(a) that the procurement process complies with the principles set out in subsection (2); and

(b) that any agreement entered into as a result of the procurement is economically prudent and cost effective, taking into consideration, but not limited to,

(i) all costs associated with the agreement, and

(ii) the costs of the agreement relative to any prior agreement entered into by the distributor for comparable acquisitions. O. Reg. 427/06, s. 2 (1); O. Reg. 235/08, s. 3 (1).

(2) Distributors shall ensure that a procurement process in relation to the smart metering initiative complies with the following principles:

1. The procurement process, including the procedures used in the process and the selection criteria, must be fair, open and accessible to a range of interested bidders.
2. The procurement process must be competitive.
3. Conflicts of interest, both actual and potential, of bidders must be disclosed in the bidders' proposals and the process must ensure that,

   i. the selected bidder will not have a conflict of interest in respect of the deliverables under the agreement entered into as a result of the procurement, or

   ii. the selected bidder will be required to comply with requirements established by the distributor to address an actual or potential conflict of interest.
4. There must be no unfair advantage in the procurement process. O. Reg. 427/06, s. 2 (2).

(3) A distributor may only procure or utilize smart meters from an affiliate, if the affiliate is the selected bidder in a procurement process that satisfies the requirements of this section. O. Reg. 427/06, s. 2 (3); O. Reg. 235/08, s. 3 (2).

(4) The Minister or the Board may on notice require that a distributor provide to the Minister or the Board, as the case may be,

(a) information relating to the procurement or installation of smart meters including information concerning pricing, contractual arrangements, and status of installations; and

(b) information relating to a procurement, which information was obtained or developed during the procurement, including information concerning the selection of the successful bidder. O. Reg. 153/07, s. 2; O. Reg. 235/08, s. 3 (3).

(5) The notice in subsection (4),

(a) shall be in writing;

(b) shall set out a time frame in which the distributor must reply; and

(c) shall specify the information that the distributor must supply. O. Reg. 427/06, s. 2 (5).

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ONTARIO REGULATION 235/08

made under the

ELECTRICITY ACT, 1998

Made: June 17, 2008
Filed: June 25, 2008
Published on e-Laws: June 26, 2008
Printed in *The Ontario Gazette*: July 12, 2008

Amending O. Reg. 427/06

(Smart Meters: Discretionary Metering Activity and Procurement Principles)

Note: Ontario Regulation 427/06 has previously been amended. Those amendments are listed in the Table of Current Consolidated Regulations – Legislative History Overview which can be found at www.e-Laws.gov.on.ca.

1. Ontario Regulation 427/06 is amended by adding the following section:

Definition

0.1 In this Regulation,

"smart meters" includes smart meters, metering equipment, systems and technology and any associated equipment, systems and technologies.

2. (1) Subsection 1 (1) of the Regulation is amended by adding the following paragraph:

3.1 Metering activities conducted by a distributor listed in paragraph 3, if the smart meters were procured subsequent to the process referred to in paragraph 3.

(2) Paragraph 4 of subsection 1 (1) of the Regulation is amended by striking out "meters, metering equipment, systems and technology and any associated equipment, systems and technologies" and substituting "smart meters".

(3) Paragraph 6 of subsection 1 (1) of the Regulation is amended by striking out "meters, metering equipment, systems and technology and any associated equipment, systems and technologies" and substituting "smart meters".

(4) Subsection 1 (1) of the Regulation is amended by adding the following paragraph:

8. Metering activities conducted by a distributor that has procured its smart meters pursuant to and in compliance with the parameters and process established by the Request for Proposal for Advanced Metering Infrastructure (AMI) – Phase 1 Smartmeter Deployment dated August 14, 2007, together with any amendments to it, issued by London Hydro Inc.

(5) Subsection 1 (2) of the Regulation is amended by striking out "meters, metering equipment, systems and technology and any associated equipment, systems and technologies" and substituting "smart meters".

(6) Subsection 1 (2.1) of the Regulation is amended by striking out "meters, metering equipment, systems and technology and any associated equipment, systems and technologies" and substituting "smart meters".

3. (1) Clause 2 (1) (b) of the Regulation is revoked and the following substituted:

(b) that any agreement entered into as a result of the procurement is economically prudent and cost effective, taking into consideration, but not limited to,

(i) all costs associated with the agreement, and

(ii) the costs of the agreement relative to any prior agreement entered into by the distributor for comparable acquisitions.

(2) Subsection 2 (3) of the Regulation is amended by striking out "metering equipment, systems and technology and any associated equipment, systems and technologies".

(3) Clause 2 (4) (a) of the Regulation is amended by striking out "metering equipment, systems and technology and any associated equipment, systems and technologies".

4. This Regulation comes into force on the day it is filed.

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Appendix D

a) Ontario Regulation 393/07

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ONTARIO REGULATION 393/07

made under the

ELECTRICITY ACT, 1998

Made: March 28, 2007
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Published on e-Laws: July 27, 2007
Printed in *The Ontario Gazette*: August 11, 2007

DESIGNATION OF SMART METERING ENTITY

Designation of IESO

1. The IESO is designated as the Smart Metering Entity.

Non-application of *Business Corporations Act*

2. Other than as prescribed in Ontario Regulation 610/98 (The IMO) made under the Act, the *Business Corporations Act* does not apply to the IESO.

Exemption, s. 53.10 of Act

3. The IESO is exempt from section 53.10 of the Act.

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PRP International, Inc.

Fairness Advisory Services

March 15, 2010

Mr. John Walsh
President & CEO
Rideau St. Lawrence Distribution Ltd.
985 Industrial Road, Box 699
Prescott, ON K0E 1T0

Dear Mr. Walsh:

Subject: Attestation Letter (Negotiations) of the Fairness Commissioner
Rideau St. Lawrence Distribution Ltd.–Elster Metering Contract Award
Advanced Metering Infrastructure RFP, August 2007
London Hydro & Consortium of LDCs Smartmetering Project

PRP International, Inc. is pleased to submit its Attestation Letter (Negotiations) of the Fairness Commissioner for the noted negotiations and contracting phase of the London Hydro AMI Request for Proposal (RFP) procurement. This judgment is being provided for the information and use of Rideau St. Lawrence Distribution Ltd., in its administration of the contract awarded to its #2 ranked Proponent, Elster Metering following unsuccessful negotiations with its #1 ranked Proponent, Silver Spring Networks.

"It is the judgment of PRP International, Inc. (as the Fairness Commissioner engaged by Rideau St. Lawrence Distribution Ltd. *for the phase of negotiations and contract award) that the successful conclusion of negotiations and contract award to* Elster Metering, *was undertaken in accordance with the principles for such negotiations and contract award set out in the RFP, issued August 14, 2007 and the Fairness Protocol, issued August 2008."*

A backgrounder and summary of the Fairness Protocol is attached and forms part of this Attestation Letter (Negotiations).

Yours truly,

Peter Sorensen

Peter Sorensen
President

Attachment: Negotiations and Contract Phase Backgrounder

203 - 8 Queen Street, Summerside, PEI C1N 0A6
Direct telephone: 902.436.3930 Fax: 604-677-5409
Email: fairness@telus.net

BACKGROUNDER TO FAIRNESS CONFIRMATION / ATTESTATION
Advanced Metering Infrastructure Procurement

TO WHOM IT MAY CONCERN:

Background:

- A Request for Proposal procurement transaction was conducted by London Hydro Inc., as the lead sponsoring Local Distribution Company (LDC) and with a consortia of another 63 LDCs, during the period August 2007 to July, 2008;
- The evaluation and selection phase of the RFP provided for the determination of the #1 and #2 ranked Proponents for each LDC;
- RFP Provision 7.5.14[1] provides the framework (principle) for negotiations and contracting based on the principle of "first right to negotiation and execution of a contract" being accorded to the ranked order of Proponents commencing with the highest ranked Proponent and proceeding in a consecutive order thereafter; and
- Each LDC was provided the evaluation results for their #1 and #2 ranked Proponents supported by the Attestation Letter of the Fairness Commissioner as to those rankings.

Fairness Coverage Objective:

Normally, fairness coverage terminates with the determination of the ranked Proponents following the evaluation and selection phase of the RFP; however, certain LDCs expressed a wish to secure additional fairness coverage during the subsequent phase of negotiations and contract award. The objective for this second phase fairness coverage is to assure that LDCs undertook a phase of negotiations and contracting that meets the RFP provisions of consecutive negotiations where required, e.g. with their top two ranked Proponents and in the event of unsuccessful negotiations with the #1 ranked Proponent, a subsequent contract award to the next ranked Proponent would be on an equitable basis as was the requirements in the negotiations with the #1 ranked Proponent.

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1 7.5.14 **Final Contract Negotiations**

Any conditions and provisions that a bidder seeks shall be a part of this proposal. Notwithstanding, nothing herein shall be interpreted to prohibit London Hydro from introducing or modifying contract terms and conditions during negotiation of the final contract.

London Hydro has scheduled no more than two weeks for contract negotiations (if necessary), and expects the successful bidder to maintain a prompt and responsive negotiation to accomplish and complete final contract agreement within that time period. If contract negotiations exceed an interval acceptable to London Hydro, London Hydro retains the option to terminate negotiations and continue to the next apparent successful bidder, at the sole discretion of London Hydro. Said interval shall in no event be less than three weeks.

BACKGROUNDER TO FAIRNESS CONFIRMATION / ATTESTATION
Advanced Metering Infrastructure Procurement

Fairness Protocols:

- A Fairness Protocol was developed and issued to all LDCs, in August 2008 that set forth the best practices for fair consecutive-based negotiations and contract award.
    - The fundamental principle of the Protocol was the requirement for the LDC to establish the negotiations agenda for their top ranked Proponents and submit a copy to the Fairness Commissioner prior to engagement of their #1 ranked Proponent, i.e. the agenda would demonstrate a common statement of work, a LDC standard for pass/fail in their negotiations and the negotiation issues would only differ to the extent of the respective Proponent's technical solution being offered.

Form of Fairness Confirmation / Attestation[2]:

1. A confirmation of fair negotiations and contract award would be issued if the LDC's #1 ranked Proponent was awarded a contract; the original Attestation Letter remains in effect.

2. An Attestation of fair negotiations and contract award would be issued if the LDC determined that their #1 Proponent was to be set aside and the LDC successfully contracted with their next ranked Proponent, e.g. their #2; the original Attestation Letter is thus superseded by the Negotiations and Contract Award Attestation Letter.

Local Distribution Company:

Rideau St. Lawrence Distribution Ltd.
Mr. John Walsh
President & CEO
Rideau St. Lawrence Distribution Ltd.
985 Industrial Road, Box 699
Prescott, ON K0E 1T0

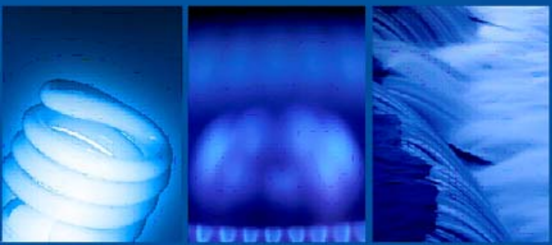
---

[2] **Conditions on the rendering of this Confirmation/Attestation.**

- The two Negotiations Agenda were provided by RSLDL via their agent Util-Assist Inc.;
- Fairness Commissioner undertook no direct participation or oversight in the negotiations between RSLDL and either of their #1 or #2 ranked Proponents;
- The successful contract award was based on the RSLDL criteria and no independent analysis nor any comparison with the evaluation results of the RFP process was carried out by the Fairness Commissioner; and
- The confirmation of the Fairness Commissioner was based on the progress report(s) provided by RSLDL via their agent Util-Assist Inc.

util-assist

utility strategic operational assistance



CornerstonE
Hydro Electric Concepts

Request for Proposal

Smart Meter Installation Services
RFP#: 2008-1024

October 24, 2008

Section 1: Introduction

1.1 Background

Cornerstone Hydro Electric Concepts (CHEC) members have been working collaboratively through the planning and preparation stages for the Smart Meter Initiative. The CHEC Group is an association of electricity distribution utilities modeled after a cooperative to share resources and proficiencies as the Ontario electricity industry continues its transformation.

The mission of the CHEC Group is to be recognized as the premier LDC Cooperative in the province, by meeting or exceeding member expectations through the sharing of services, opportunities, knowledge and resources. The values of the CHEC Group include the sharing of resources, both intellectual and technical, enabling members to deliver value to their customers and shareholders ensuring competitiveness in the marketplace. Together the mission and value statements represent lofty but attainable goals for the CHEC Group.

Collaboratively the CHEC group represents more than 110,000 residential end points in Ontario and is comprised of the following member utilities:

Centre Wellington Hydro Ltd.	Orangeville Hydro Limited
COLLUS Power Corp.	Orillia Power Distribution Corporation
Grand Valley Energy Inc.	Parry Sound Power Corporation
Innisfil Hydro Distribution Systems Ltd.	Rideau St. Lawrence Distribution Ltd.
Lakefront Utilities Inc.	Wasaga Distribution Inc.
Lakeland Power Distribution Ltd.	Wellington North Power Inc.
Midland Power Utility Corporation	Westario Power Inc.

CHEC members wish to procure Installation Services from a qualified Bidder at a firm, fixed price; this documentation sets out the procedural and technical requirements of CHEC for its Advanced Metering Infrastructure (AMI) System Installation service requirements.

1.1.1 Provincial Mandate

As part of its energy conservation effort, the Ontario government has made a commitment to replace all existing meters (5 million) with smart meters by 2010. Phase One utilities have fulfilled their commitments to install 1 million smart meters by Dec 31, 2007 which assisted the government in exceeding their interim goal of 800,000 by Dec 31, 2007. Focus now shifts to the Phase Two implementation of a Smart Meter Network.

The underlying premise behind the provincial mandate to install these meters is to educate customers on their consumption habits and implement new rate structures that will encourage load shifting, and the conservation of energy.

1.1.2 The CHEC Approach to Smart Metering

With respect to the Provincial government’s Smart Metering Initiative, CHEC has taken a collaborative approach to becoming educated on this mandate by working with other Ontario utilities and advocacy groups. CHEC hopes to evaluate Bidders as objectively as possible with the end goal of selecting the best-fit service provider for implementation services, thereby allowing CHEC to achieve their goals, as well as those of the provincial smart meter mandate.

Along with satisfying the provincial mandate of measuring "how much electricity a customer uses each hour of the day, and to use that data to charge customers an energy price that varies depending on when the electricity was consumed" (OEB Smart Meter Plan; January 26, 2005; page i); CHEC will also implement the Smart Meter Network to improve overall efficiency within the associated service territories.

Real time connectivity with the end use consumer through the installed networks will allow for improvements in the maintenance and management of the distribution network (i.e. improved outage management and restoration) and the utilization of existing infrastructure (e.g. Fibre) where available, will allow for cost effective implementation of these systems.

1.1.3 AMI Terminology

For the purposes of this procurement process, CHEC have opted to utilize the terminology as defined by the Ministry of Energy in their *Functional Specification for an Advanced Metering Infrastructure Version 2* (dated July 5, 2007), Section 3, *Definitions.* For reference, this document has been included herein as Appendix "A". Any additional terms that have been utilized in this document, which have not been defined in the aforementioned document, which may require clarification, have been defined in Section 1.1.4 *Other Terms*.

1.1.4 Other Terms

1. ***Route Acceptance*** shall refer to the process by which CHEC accepts an existing meter reading route as having been 100% saturated with the AMI being installed through this RFP. Route Acceptance is the process which definitively determines whether the responsibilities of the Installation Vendor (being procured through this document) have been achieved.
2. ***Bidder*** shall refer to the vendor proposing a solution to this RFP document by submission of a Proposal.
3. ***Costs** and **Price***. Within this document, the terms "Costs" and "Price" are used interchangeably, and should be interpreted as including conversion costs, life-cycle costs, etc. Bidder should be sure to provide details regarding the amount charged for the given commodity or service.
4. ***Proposal*** shall mean the Bidder's written response provided to CHEC in accordance with this RFP. The Proposal shall include all written material submitted by Bidder as of the date set forth in the Key Dates (Section 2.1 *Key Dates*).
5. ***Unsafe Meter*** shall mean meters, meter bases, or other infrastructure which creates an electrically unsafe situation for the meter installer or for the general public. This can include situations where access to the meter for the purpose of meter exchange poses a safety risk (i.e. confined spaces). The manner in which Unsafe Meters are to be dealt with has been detailed in Section 3.2.2 *Unsafe Meter Bases*.
6. ***Refused Access*** shall refer to situations where the customer is present at the location where a meter exchange is required, but refuses access to the meter. It is expected that the Installer would accommodate unique situations such as Refused Access through the policies and procedures which CHEC have requested in Section 7: *Customer Communications*.
7. ***Non Installable Account*** is the "Comment Code" or "Note" that will be used by the Bidder to indicate that a meter installer has visited a premise (3) times and utilized telephone scheduling attempts two (2) times, and has not been successful at installing a meter. In this case the meter exchange service order can be returned to CHEC for resolution with no associated implications for not meeting installation targets.
8. ***Installer*** shall refer to the successful Bidder. The term Installer will be used when stating future requirements, to be performed only by the successful Bidder.

9. ***Field Service Representative*** or ***Field Service Personnel*** shall refer to the employees of the Installer which are actually performing the work, and which are monitored by the Installer to ensure proper protocols are followed.
10. ***Contractor*** shall refer to the Electrical Contractor retained by CHEC for upgrading infrastructure, and performing any other services beyond the scope of this document.

1.2 Description of Environment

Please refer to CHEC_InstallationRFP_PricingSheet_Oct2008.xls for details regarding customer count, meter count, etc.

Section 2: Instructions to Bidders

This Request for Proposals (RFP), establishes the system products and services that CHEC wishes to acquire. This bid document is the basis upon which CHEC seeks firm proposals from selected Bidders and upon which proposals will be evaluated. The documents are:

- This RFP (a pdf document), including Appendices that are integral to it.
- CHEC_InstallationRFP_PricingSheet_Oct2008.xls, a Microsoft Excel workbook. This file contains scoring criteria, the compliancy signoff sheet that is to be printed and included with the response, and tabs that allow for entry of pricing information. This workbook will heretofore be referred to as the Pricing and Compliancy spreadsheet.

2.1 Key Dates

Below is the expected timeline that CHEC will be following during the evaluation of submitted proposals. As can be seen, it is the intention of CHEC to make its decision by December 19, 2008. This time line will allow for contract negotiation and signing, so that installation can begin according to the anticipated start date of February 2, 2009.

Installation Services RFP released by CHEC :	**October 24, 2008**
Intention to bid:	**October 31, 2008**
Final Questions Due:	**November 7, 2008**
Answers to Questions:	**November 14, 2008**
Closing Time (Proposals Due):	**3:00 pm; November 21, 2008**
Proposal Decision:	**December 19, 2008**
Anticipated Start Date:	**February 2, 2009**
Required Project Completion Date:	**April 30, 2010**

2.2 Intention to Bid

Recipients of this RFP are asked to inform CHEC of their intention to bid, by completing the template form found in Section 2.15 *Proposal Forms*, and by submitting this form by the date shown in Section 2.1 *Key Dates*. Recipients that express intention to bid will be included in all correspondence (if any) during the bidding process. Please provide full contact information and expression of intention via the provided form to the CHEC contact named in Section 2.4 *Submission of Bids*.

2.3 Components of Service

It is the intent of CHEC to procure a turn-key solution. Strategic alliances may be formed to provide a turn-key solution, or Bidders may be interested in performing only certain components of the project. Bidders are asked to clearly indicate which components of the Project are being bid.

CHEC reserves the right to award some, none, or all of the components through this process to one or many Bidders.

2.4 Submission of Bids

Proposals submitted in response to this RFP will be submitted by 3:00 PM Eastern Time on November 21, 2008 (the due date, as per Section 2.1 *Key Dates*) to:

Attn: Ms. Ruth Tyrell
CHEC Group
c/o Orangeville Hydro
400 C Line
Orangeville, ON L9W 2Z7

Bidders are requested to submit bids that are complete and unambiguous without the need for additional explanation or information. CHEC reserves the right to make a final determination as to whether a bid is acceptable or unacceptable solely on the basis of the bid as submitted, and proceed with bid evaluation without requesting further information from any Bidder. If CHEC deems it desirable and in its best interest, CHEC may, in its sole discretion, request from any Bidder or Bidders additional information clarifying or supplementing any submitted bid.

Proposals received after the due date will remain unopened and will not be considered for selection. CHEC does not currently plan to grant extensions of the proposal due date, but reserves the right to do so. In the unlikely case that an extension is granted, notice of such extension will be provided to all Bidders at least one week prior to due date. Proposals will be submitted in hard copy to the street address above. All Proposals will remain the property of CHEC members.

2.4.1 Submission Requirements

1) A complete Proposal will consist of one (1) original and thirteen (13) copies complete with all supporting data, and one (1) electronic soft copy complete with all supporting data.
2) Accompanying the Bidder's response document should be the Proposal Form provided in Section 2.15 *Proposal Forms*.
3) The required format of the Bidder's response document is outlined in Section 2.4.3 *Proposal Format Instructions*.
4) The Pricing and Compliancy spreadsheet will allow for the Bidder to enter their pricing information in a standard format, as well as allow the Bidders to attest to their company's compliancy with the appropriate Health and Safety Requirements. Failure to properly complete this document is grounds for disqualification, as highlighted in Section 2.4.4 *Grounds for Disqualification*.
5) The original hard copy shall be clearly identified as "ORIGINAL"; the remainder (i.e. thirteen copies) shall be marked as "COPY". In the event of discrepancy between the copies of the Proposal Submission, the one marked "ORIGINAL" shall prevail. Each Bidder's submission shall consist of the required documents with the required number of copies of all commercial information, including pricing, terms and conditions and exceptions (if applicable). Faxed or late Proposals will not be accepted. Proposals must be sealed and marked clearly quoting the Proposal Number referred to on the cover sheet of the Proposal Documents. The use of any means of delivery of a Proposal shall be at the risk of the Bidder.
6) Any Bidder wishing to provide additional information other than what is requested in the RFP Document must place such additional information in a separate envelope marked Additional Information attached to the outside of the Proposal envelope. Any Additional Information or any unsolicited value-added alternatives may, in CHEC's absolute discretion, be given due consideration, or not.
7) CHEC shall not be liable for, nor shall it reimburse any Bidder for costs incurred in the preparation of Proposals, or any other services or samples that may be requested as part of the evaluation process.
8) The Proposal Forms shall be signed under the Corporate Seal of the Bidder, by the duly authorized signing officer(s). All submitted pages shall be initialled by such officer(s).

2.4.2 Pricing and Compliancy Spreadsheet

A Microsoft Excel workbook has been provided with this pdf document (entitled CHEC_InstallationRFP_PricingSheet_Oct2008.xls). The following tabs are included within this Pricing Spreadsheet:

i) CHEC_BidderCompliancy: This tab requires completion by the Bidder, and will act as their compliancy statement according to the requirements of Section 2.4.4 *Grounds for Disqualification*.

ii) Pricing_Option1: Option 1 tabs require completion by the Bidder, and represents the pricing for the Bidder to provide installation services as outlined within this RFP. Within the spreadsheet there are 14 tabs provided for Option 1, allowing the bidder to provide pricing according to Option 1 requirements (i.e. services as outlined within the RFP) for each utility individually, as well as for the utilities acting collaboratively. It is hoped that there will be incentive to continue moving forward through this initiative in a collaborative manner.

iii) Pricing_Option2: This tab is optional and allows the Bidder to provide pricing in an alternative format, should they desire to do so, and are of the opinion that their services are better represented with pricing apart from that outlined on the Pricing_Option1 tab. Bidders are free to add additional pricing tabs as required should they feel that there are more than one alternative option which may allow for more competitive pricing (i.e. according to a more or less aggressive timeline, holding off project commencement until a different time of year (i.e. spring vs, winter, etc.)).

Note: Pricing_Option1 is mandatory, Pricing_Option2 is optional.

iv) Eval_Criteria: this tab is for reference, it is a copy of the table that is shown in Section 2.9 *Proposal Evaluation*.

v) WFM_Functionality: This tab requires completion by the Bidder, and will demonstrate the functionality inherent to the WFM system being utilized to provide installation services.

2.4.3 Proposal Format Instructions

Each Bidder's response will be organized as per the following:

a) Section 1 of the proposal will contain the Bidder’s Executive Summary, no more than two pages in length that introduces the Bidder and highlights key features of the proposal.

b) Section 2 of the proposal will contain the statement of compliance that is included within the Pricing and Compliancy Spreadsheet, and which is described in Section 2.4.2 *Pricing and Compliancy Spreadsheet*, subsection i).

c) Section 3 of the Bidder’s proposal will contain the requirements of Section 3 of this RFP Document (Section 3: *Health and Safety*), in the order presented in this document, with the numbering used in this document.

d) Section 4 of the Bidder’s proposal will contain a statement of recognition that the Bidder understands CHEC’s schedule for deployment and the deployment territories, and that they are providing a bid response with the intention of performing the required services for CHEC. Given the diverse nature of the service territories, and that there are Smart Meter deployments occurring across the province, Bidders have the opportunity within this section to demonstrate, through submitted documentation/statements, how they will be able to accommodate the unique requirements of CHEC (i.e. staffing across the area, for the timelines projected).

e) Section 5 of the Bidder’s proposal will contain the requirements of Section 5 of this RFP Document (Section 5: *Bidder Information*), in the order presented in this document, with the numbering used in this document.

f) Section 6 of the Bidder's proposal will contain the requirements of Section 6 of this RFP Document (Section 6: *Installation Services*), in the order presented in this document, with the numbering used in this document.

g) Section 7 of the Bidder's proposal will contain the requirements of Section 7 of this RFP Document (Section 7: *Customer Communications*), in the order presented in this document, with the numbering used in this document.

h) Section 8 of the Proposal **should be provided in a separate envelope which has been clearly marked "PRICE OFFER".** This section will contain the summary pages pertaining to the Price Offer, contained within the Pricing and Compliancy Spreadsheet. The Bidder's detailed itemized pricing information for all goods or services is to be contained within the Pricing and Compliancy Spreadsheet which is to be included with the response in its entirety as well as within this section. Any alternative pricing offers may also be included within the Pricing and Compliancy Spreadsheet (tab Pricing_Option2 is included for this purpose, as described in Section 2.4.2 *Pricing and Compliancy Spreadsheet*). All pricing shall be expressed in Canadian currency, exclusive of taxes.

2.4.3.1 Sample Responses to Demonstrate Format

Within the section or subsection heading an indicator has been included to specify whether the Bidder should provide information pertaining to the functionality of their product/service (with regards to the section requirements), or a statement of compliancy AND information pertaining to the functionality of their product with respect to the requirement of the section. Where no indicator is included, a response is not required.

(I) When an (I) has been included with the section heading, CHEC requires Information regarding the proposed system's functionality, and the methodology utilized to satisfy the RFP requirement.

(C) When a (C) has been included with the section heading, CHEC requires a statement of compliancy from the Bidder. Within the proposal documentation, the Bidder is required to state the compliancy with the requirement by stating Fully Compliant, Partially Complaint, or Not Compliant.

(CI) When a (CI) has been included with the section heading, CHEC requires both a statement of compliancy, and Information regarding the proposed functionality, and the methodology utilized to satisfy the RFP requirement.

The method with which the Bidder provides information and compliancy statements is detailed within the individual sections, as well as within the Pricing and Compliancy Spreadsheet.

In Section 2.4.3 Proposal Format Instructions, subsections c) through g) it has been specified that the order and numbering used within this document be utilized. A sample has been provided here.

5.2 Company Size and Location (I)

What is the current size (number of employees), turnover rates for last three (3) years, and location(s) of the Bidder's company?

Bidder's Functionality Statement: Bidder X currently employs 600 employees. 500 of these employees are Field Service Representatives. Of the 100 remaining office and management staff, 37 are within the Operations division providing ample redundancy and support to effectively manage this project. Bidder X's head office is located in Alabama, with satellite offices in Toronto, London, and

Ottawa. This project will be managed from the Toronto office. Turnover, while generally higher in the field service industry, is considered low at 3%. We attribute this to an effective Safety and Training program (1 week) in which employees receive ample safety training as well as introduction to the company incentive program which has been seen to improve morale amongst field service employees.

SAMPLES of response for Section 6: *Installation Services*, demonstrating that the section numbering from this document is to be retained, and that each section should be included, and where required shall include a statement of compliance.

6.1.1 Minimum Competencies (C)

Before installing meters the Installer shall ensure the Field Service Personnel are customer service oriented, have flexible work hours and are bonded, and the Installer shall maintain a process to ensure these requirements are met.

The Installer shall operate within specific procedures and operating conditions in adherence with procedures and training that CHEC will provide. Upon conclusion of the CHEC training, it will be the Installer's responsibility to ensure that new employees receive the same level of training as those employees which receive the training through CHEC.

Bidder's declaration of compliance: **Fully Compliant**

6.5.6 GPS (CI)

In addition to installing the meter, capturing the LAN ID and Meter ID data from the barcode on the installed meter, and the start read, CHEC desires to update service location information by having the Bidder capture the GPS co-ordinates of the installed endpoint. Where meters are located in basements or in areas where satellite signal may not be possible, the closest co-ordinates will be collected once communication has been established.

Bidder's declaration of compliance: **Fully Compliant**

Bidder's Functionality Statement: The WFM system is capable of automatically capturing the GPS location of the installed meter, and this information is automatically recorded within the assigned service order. The GPS device is integrated (i.e. not a separate device), and is accurate to within 3m (10 feet).

2.4.4 Grounds For Disqualification

It is a requirement of this RFP document that the Bidders submitting proposals for evaluation complete a compliancy spreadsheet which will attest to the Bidder's compliance with the Health and Safety Policies and Procedures as outlined in Section 3.1 *CHEC Health and Safety Policies and Procedures*. In addition to having read this section, and all applicable subsections, the Bidder agrees that their company's own Health and Safety Policies will, at minimum, meet CHEC's Safety Policies, and that their bid response will provide the information to properly satisfy the requirements of Section 3.2 *Safety* (and applicable subsections), and that the content of the response is consistent with the policies being agreed to here.

NOTE: Failure to complete these compliancy documents (found within the Pricing and Compliancy Spreadsheet; tab named "CHEC_BidderCompliancy", or where compliancy has been misrepresented, CHEC reserves the right to disqualify the Bidder from contention of the RFP process.

2.5 Clarifications

Upon the issuance of this RFP to Bidders, and continuing through the submission date, all questions or other communications with CHEC shall be by email only, with CHEC's authorized representative, whose contact information is provided in Section 2.4 *Submission of Bids*.

CHEC will respond to the question in writing, with both the question and response provided to each Bidder that has declared intention to bid according to Section 2.2 *Intention to Bid*. No response will be made to questions submitted after November 7, 2008 (as per Section 2.1 *Key Dates*).

2.6 Modifications or Withdrawals of Bids

A Bidder may modify or withdraw its bid by written declaration, provided that the declaration is received by the CHEC contact specified in Section 2.4 *Submission of Bids* prior to the time specified for the submission of bids (the due date). Following withdrawal of its bid, a Bidder may submit a new bid, provided that such new bid is received by CHEC prior to the due date. The last bid received by CHEC shall supersede and invalidate all bids previously submitted by the Bidder.

CHEC may modify any provision of the Request for Proposal at any time prior to the due date. Such modifications may be made in the form of addenda, which will be issued simultaneously to all prospective Bidders that have declared their intention to bid. No addenda will be issued within five calendar days of the due date.

2.7 Bid Inconsistencies

Any provisions in Bidder's proposal that are inconsistent with the provisions of this Request for Proposals, unless expressly described in the proposal as being exceptions or alternates, are deemed waived by the Bidder. In the event the Order is awarded to Bidder, any claim of inconsistency between the proposal and this RFP will be resolved in favour of this RFP unless otherwise agreed to in writing by CHEC.

2.8 Post-Bid Meeting

CHEC reserves the right to invite any or all Bidders to make an in-person presentation on the proposed smart meter installation services.

2.9 Proposal Evaluation

CHEC will evaluate proposals using an internal scoring method that weights various parameters to give the CHEC team insight into the strengths of each proposal relative to CHEC member utility's needs.

Answers to sections 3 through 7 will represent 40% of the total weighting of the RFP. Pricing submitted will represent 60% of the total weighting of the RFP. Bidders will be selected for further discussion based on the Team's judgment, developed using the scoring method. CHEC's internal scoring method values the following proposal attributes (order of presentation does not reflect priority):

Figure 1: Proposal Evaluation Criteria

Proposal Evaluation Criteria	Section	% Total Points
Safety	3	
Project Overview	4	
Bidder Information	5	
Installation Services	6	
Service Offering / Capability		
Inventory Control		
Scheduling and Coordination		
Reporting		
Used Meter Disposal Handling		
A to S Adaptor Installation		
Meter Base Repairs		
Tamper / Theft		
Customer Communications	7	
Call Centre		
Pre Canvas		
Perspectives expressed by reference utilities		
Section 3 through 7 inclusive:		**40%**
Pricing Weighting:		**60%**
Total		**100%**

2.10 Award or Rejection

Issuance of this RFP does not constitute a commitment by CHEC to award a winning Bidder or purchase products or services offered in response to this RFP. CHEC reserves the right to reject any or all bids. CHEC will not reimburse Bidders' costs to respond to this RFP.

2.11 Execution of the Order

If requested by CHEC, the successful Bidder must assist CHEC in preparing the Purchase Order, which will be governed by the Terms and Conditions set out herein, or others as mutually agreed by the parties. The successful Bidder must duly execute the Purchase Order within ten (10) days after receipt and return it to CHEC. Failure of the successful Bidder to duly execute and return the Order, together with any other required documents will constitute a breach of contract by such Bidder and entitle CHEC to award the Order to any other Bidder, in addition to all other rights and remedies of CHEC.

2.12 Freedom of Information

Proposals submitted to CHEC become the property of CHEC and, as such, are subject to the *Freedom of Information and Protection of Privacy Act*, R.S.O. 1990, c. F.31, as amended.

2.13 Ownership of Data

CHEC shall own all data used and/or collected by any systems being utilized to perform the services. Data shall not be used for any purpose without the approval of CHEC.

2.14 Conflict of Interest

The Bidder is required to disclose in its Submission and on an ongoing basis thereafter any conflict of interest, real or perceived, that exists now or may exist in the future, with respect to this RFP, any resulting contract, or in relation to CHEC or their affiliates.

2.15 Proposal Forms

Within this section, there are two forms required for submission. The first form is found in Section 2.15.1 *Intention to Bid Form*; the intention of this form is to allow the Bidder to provide a standard email response to CHEC to notify CHEC of the Bidder's intent to respond to the RFP.

2.15.1 Intention to Bid Form

Bidders intending to respond to this RFP should notify the contact, using the contact information provided in Section 2.4 *Submission of Bids*, according to the time line as established by Section 2.1 *Key Dates,* by sending an email with the following content inserted:

INTENTION TO BID NOTIFICATION FORM

PROPOSAL NO. 2008-1024

Intention to Bid:
Please allow this email to represent "   Insert Company Name Here   " intention to respond to CHEC RFP#: 2008-1024.

Contact for communication regarding bid: ______________________
Contact phone number: ______________________
Contact email address: ______________________

We acknowledge the requirement that our company meets the minimum Safety Requirements as outlined in Section 3. Our proposal will include the required compliance statements and documents to properly express our ability to meet these requirements. We also acknowledge the Submission Deadline is 3:00 pm Eastern Time on November 21, 2008.

2.15.2 RFP Submission Form

The procedure to be utilized for the RFP Submission form is to print the following pages, and include them with the RFP submission, which should be addressed to the designated contact listed in Section 2.4 *Submission of Bids*, and which should be submitted according to the time line as established by Section 2.1 *Key Dates*.

RFP SUBMISSION FORM

Cornerstone Hydro Electric Concepts (CHEC)

Proposal Number: **RFP# 2008-1024**

FOR: Installation Services

THIS PROPOSAL IS SUBMITTED BY:____________________

ADDRESS:

TELEPHONE: FAX NO.:

BIDDER G.S.T. No.:

PERSON(S) SIGNING ON BEHALF:____________________________(print)

POSITION(S) OF THE PERSON(S):__________________________________(print)

To Cornerstone Hydro Electric Concepts, Hereafter called "Owner":

I/WE ____________________________________ the undersigned declare:

1. THAT no Person(s), Firm or Corporation other than the one whose signature(s) of whose proper officers and the seal is or are attached below has any interest in this Proposal or in the contract proposed to be taken.

2. THAT this Proposal is made without any connections, knowledge, comparison of figures or arrangements with any other company, firm or person making a Proposal for the same work and is in all respects fair and without collusion or fraud.

   THE Bidder insures that no Owner and or employee of the CHEC group, is, or has become interested, directly or indirectly, as a Contracting Party, Partner, Stockholder, surety or otherwise howsoever in or on the performance of the said contract, or in the supplies, work or business in connection with the said contract, or in any portion of the profits thereof, or of any supplies to be used therein, or in any monies to be derived there-from.

3. THAT the several matters stated in the said Proposal are in all respects true.

4. THAT I/WE have carefully examined the requirement(s), as well as all sections of the document including Instruction to Bidders, Project Overview, Installation Services, Proposal Forms, and Appendices relating thereto, prepared, submitted and rendered available by CHEC and hereby acknowledge the same to be part and parcel of any contract to be let for the work therein described or defined.

5. THAT I/WE do hereby Propose and offer to enter into a contract to deliver all work as described or implied therein including in every case freight, duty, exchange, G.S.T. and P.S.T. in effect on the date of the acceptance of Proposal, and all other charges on the provisions therein set forth and to accept in full payment therefore, the sums calculated in accordance with the actual measured quantities and unit prices set forth in the Proposal herein.

6. THAT Addendum/Addenda No. ___ to ___ inclusive relate to the said contract and Bidder hereby accepts and agrees to the same as forming part and parcel of the said contract.

7. THAT additions or alterations to or deductions from the said contract, if any, shall be made in accordance with the prices stated in the Schedule of Items of Unit Prices in strict conformity with the requirements of the Contract.

8. THAT this offer is irrevocable and open to acceptance until the formal contract is executed by the awarded Bidder for the said requirement(s) or Sixty (60) working days, and unit prices for as long as stated elsewhere in the document, whichever event first occurs and that CHEC may at any time within that period without notice, accept this Proposal whether any other Proposal has been previously accepted or not.

9. THAT the awarding of the contract, by CHEC is based on this submission which shall be an acceptance of this Proposal.

10. THAT I/WE also understand that CHEC reserves the right to accept or reject all or part of this Proposal or any other and also reserves the right to accept other than the lowest Proposal.

<u>The undersigned affirms that he/she is duly authorized to execute this Proposal.</u>

BIDDER'S SIGNATURE AND SEAL: ______________________________

NAME: ______________________________
(Please Print)

POSITION: ______________________________

WITNESS SIGNATURE: ______________________________

WITNESS NAME: ______________________________
(Please Print)

POSITION: ______________________________

(If Corporate Seal is not available, documentation should be witnessed)

DATED AT THE ______________________________ THIS ________
(City/Town) (Day)

DAY OF ______________________________ 2008.
(Month)

Section 3: Health and Safety

3.1 CHEC Health and Safety Policies and Procedures

Sections 3.1.1 *CHEC Health and Safety Policy* through Section 3.1.6 *Health and Safety Legislation that Applies* are requirements for which compliance are required in order for any external contractors to be permitted to provide services to CHEC. As such, a Statement of Compliancy pertaining to each section is required, and a form has been provided within the Pricing and Compliancy Spreadsheet as outlined in Section 2.4.2 *Pricing and Compliancy Spreadsheet*.

Section 3.2 *Safety* is where the Bidder is provided the opportunity to demonstrate, through the submitted documents, that their own internal Health and Safety Policies, either meet, or exceed those outlined in Section 3.1 *CHEC Health and Safety Policies and Procedures*. Bidders that cannot meet, or exceed those requirements outlined in Section 3.1 *CHEC Health and Safety Policies and Procedures*, or that do not (or cannot) provide a completed Compliancy statement is eligible for disqualification from the evaluation process.

3.1.1 CHEC Health and Safety Policy (C)

CHEC members proclaim that the Health & Safety of each employee is of vital importance in the successful operation of the utility.

Our objective is to develop a keen sense of health & safety awareness in each and every employee and thereby prevent personal illness/injury and damage to property and equipment.

Management is responsible for providing a healthy and safe work environment and for training employees to ensure that they can perform their duties safely.

It is the duty and responsibility of every employee to work safely with equal concern for themselves, co-workers and the public.

It is our collective responsibility to ensure compliance with legislated requirements of Occupational Health & Safety Act.

It is our commitment to provide a safe and healthy work environment by reducing hazards that cause accidents and injuries.

3.1.2 CHEC Field Service Personnel Health and Safety Conditions (C)

Based on the nature of the work being procured through this RFP, and in accordance with the CHEC Health and Safety Policy, the following items shall be received prior to the start of work:

- Acknowledgement from the contractor that they are aware of and agree to adhere to the terms and conditions.
- WSIB Certificate
- NEER firm summary statement
- Liability Insurance
- Health & Safety Policy / Program
- Staff Competency List
- Confirmation of applicable EUSA training
- Documentation of injury experience

- WHMIS MSD documentation for any hazardous materials used in the job
- Equipment Fitness List

3.1.3 CHEC Field Service Personnel Health and Safety Policy (Basic Procedures) (C)

In accordance with CHEC Operating Policies and Procedures, all installers performing work such as that being procured through this RFP shall:

- Wear rubber gloves, Category 2 Fire Retardant Clothing or better
- Class 'O' rubbers for voltage checks
- Hard Hats
- Flash glasses
- Face Shields
- Safety boots
- Ensure meter voltage and type is correct
- Observe safe limits of approach
- Observe wiring to determine if a back feed could be present, e.g. capacitors, standby generator, co-generator
- Not remove meter if meter base is damaged or not secure
- Use meter puller

3.1.4 CHEC Health and Safety Policy: Field Service Personnel (C)

In accordance with CHEC Operating Policies and Procedures, all installers performing field service work shall be:

- Responsible for knowing, understanding and working in compliance with the appropriate safety legislation, EUSA rules, CHEC member utility rules, policies, procedures and safe work practices that apply to the work.
- Responsible for using and wearing at all times the appropriate personal protective and safety equipment required for the work.
- Responsible for using the equipment, materials, protective devices in the proper and safe manner.
- Responsible for participating in, and holding tailboard conferences as required in order to safely complete the work.
- Responsible to participate in any coaching sessions, training, safety meetings, and company general meetings in order to ensure continued competence in the most up-to-date rules, policies, procedures and safe work practices.
- Responsible for reporting all hazardous conditions or equipment defects to the supervisor immediately, fill out the proper documentation and assist with corrective action.
- Responsible to ensure loss incidents and potential loss incidents are reported to the supervisor immediately. Provide preliminary details, fill out the proper documentation and participate in the incident investigation as required.
- Responsible to follow the Internal Responsibility System.
- Responsible to take every precaution reasonable in the circumstances for the protection of the safety of fellow employees.

3.1.5 CHEC Health and Safety Policy: Supervisor/Manager (C)

In accordance with CHEC Operating Policies and Procedures, all Supervisors and/or Managers of Field Personnel shall be:

- Responsible for knowing, understanding and ensuring that work is done in compliance with the appropriate safety legislation, EUSA rules, each CHEC member utility's rules, policies, procedures and safe work practices that apply to the work.
- Responsible for identifying the job hazards, determining the solutions or barriers required to provide safe working conditions and communicating this information to all workers under their supervision.
- Responsible for ensuring all job information such as tailboard conference sheets, traffic plans, vehicle and equipment inspection sheets are filled out properly and returned to the office as appropriate.
- Responsible for holding documented tailboard conferences as required and ensuring appropriate worker participation in order to complete the work safely. Responsible for directing the work in a safe manner.
- Responsible for using and ensuring all crew members use and wear at all times the appropriate personal protective and safety equipment required for the work.
- Responsible for using and ensuring all crew members use the equipment, materials, and protective devices in a proper and safe manner.
- Responsible to ensure loss incidents and potential loss incidents are reported to CHEC members immediately. Provide preliminary details, fill out the proper documentation and participate in the incident investigation as required.
- Responsible to report workers who do not comply with their health and safety responsibility, for corrective action by their supervisor.

3.1.6 Health and Safety Legislation That Applies (C)

The Provincial, Federal and Municipal acts & regulations that must be adhered to include, but are not necessarily limited to, the following:

- Bill C45
- Transportation of Dangerous Goods Act , 1992
- Ontario Occupational Health & Safety Act & Regulations
- Ontario Regulation 632/05 – Confined Spaces
- Ontario Regulation 213/91 – Construction Projects
- Ontario Regulation 835-846 – Designated Substances
- Ontario Regulation 851 – Industrial Establishments
- Ontario Regulation 860 – WHMIS
- Ontario Highway Traffic Act & Regulations
- Ontario Regulation 595 – Commercial Motor Vehicle Inspections
- Ontario Regulation 4/93 – Hours of Service
- Ontario Traffic Manual
- Ontario Regulation 22/04 – Electrical Distribution Safety
- Electrical Operations Rule Book (EUSA Rules)
- Electrical Safety Code

3.2 Safety (CI)

CHEC's number one requirement will always remain the health and safety of its employees and customers. In addition to stating compliance to CHEC Health and Safety Policies as outlined in Sections 3.1 *CHEC Health and Safety Policies and Procedures*, the Contractor shall ensure that all installation personnel complete all required training for meter installation, meter testing, and for the installation and testing of any other endpoint devices to be installed. CHEC will be expected to work with the Contractor to identify specific gaps in training and testing. The Contractor will communicate to CHEC members how it will complete all training in advance of any installations taking place. The Bidder's ability to provide the required training (according to CHEC's requirements) for successful on-time deployment must be approved and properly documented by both CHEC's Project Manager and Health and Safety Officer.

To reflect a similar commitment to Health and Safety, all contracted vendor's policies and procedures manuals will contain comprehensive documentation (as a complement to completed training programs) regarding On-The-Job Safety, Emergency Plans, Accident/Investigation Procedures, and Contact Numbers for any possible incident occurrences, as well as Hazard Assessment Identification and Control, (including (but not limited to) Dangerous Animals, Slips/Trips/Falls, Workplace Violence, Confined Spaces and Unsafe Meter Bases).

Included with the Bidder's response document should be current documentation regarding WSIB clearance.

Additionally, all contracted field service employees will provide to CHEC's designated Health and Safety Officer (prior to commencement of services), proof that contracted employees:

- Hold a valid driver's license,
- Hold valid driver's insurance,
- Have provided a Driver's Abstract to their employer,
- Have provided a Criminal Background Check to their employer.
- Provide proof of WSIB CAD Experience (WSIB Clearance Certificate)
- Provide proof of EUSA Electrical Safety and Awareness Course
- Provide proof of EUSA Electric Power Meters Course
- Health and Safety Training Program
- Environmental Management System Training
- Utilize Tailboard Conference/Tailgate Safety Talks
- Conform to Technical, Quality Assurance, and other CHEC member specific training requirements
- Have received WHMIS Training
- Have any necessary First Aid Training/CPR Training
- Have received Customer Service Training
- Have completed In-field Training
- Comply with CHEC member utility's Contractor Checklist

Note: There is a requirement (as per Section 2.4.4 *Grounds For Disqualification*) for Bidders to declare compliancy with the appropriate safety regulations. Failure to do so will make the Bidder's response eligible for disqualification from the remainder of the evaluation.

3.2.1 Safety Policies (I)

CHEC believes that none of its meter sites presents a threat to the personal safety of field workers. It is the responsibility of the Bidder to ensure the safety of their staff, and to ensure that the necessary precautions are taken to ensure the security of any required tools.

i. Bidders shall describe their training and safety program.
ii. Bidder will provide their Health and Safety Policies and Procedures manual, complete with listing of assigned equipment, and required PPE. Documentation on the competency of staff utilizing PPE will also be provided.
iii. Bidder will provide the Emergency procedures that are provided to their installation staff; and indication that relevant staff have been trained on the procedures.
iv. Bidder should provide their Joint Health and Safety Committee meeting schedule/frequency, and membership.
v. Bidder should provide details on the number of staff that meet the safety requirements as outlined.

CHEC reserves the right to review and approve training materials and methods before the start of deployment. Bidders should note that CHEC Safety Committee members will be conducting their own random audit process on installation staff.

3.2.2 Unsafe Meter Bases (I)

Bidders should provide details on their procedures for the handling of meter sites where installation is delayed by unforeseen circumstances such as required infrastructure upgrade, accident, or customer objection. Bidders will describe notification procedures and method for tracking the status of such sites.

Acceptable security precautions are to be maintained during all installation activities. The Installer will identify, report and resolve unsafe conditions on a daily basis or as they are identified according to established safety policies. In the case of electrical or mechanical hazards, these shall be reported to CHEC immediately.

Some meter bases have been deemed unsafe. The Contractor shall not attempt, at any time, to remove a meter that has been deemed unsafe. When encountered, the Contractor will be required to identify unsafe meter bases in the WFM handheld device using the appropriate codes and notify CHEC's Installation coordinator. Bidders shall include, within their response, a description of the procedures that are invoked upon discovery of an unsafe meter base, as well as description of the pre-installation inspection protocols which may result in the discovery of an unsafe meter base.

Section 4: Project Overview

Section 4 of the Bidder's proposal shall contain a statement of recognition that the Bidder understands the CHEC's schedule for deployment and the deployment territory, and that they are providing a bid response with the intention of performing the required services for CHEC. Given the diverse nature of the service territory, and that there are Smart Meter Deployments occurring across the province, Bidders have the opportunity within this section to demonstrate, through submitted documentation/statements, how they will be able to accommodate the unique requirements of CHEC (i.e. staffing across the area, for the timelines projected).

4.1 CHEC Anticipated Schedule for Deployment (C)

Section 2.1 *Key Dates* shows the anticipated start date for deployment, and the end date required by CHEC. Within this time frame, the successful Bidder will be required to install the quantity of Smart Meters documented in Section 4.4 *Installation Volumes*. (The statement of recognition that is required for Section 4: *Project Overview* should include recognition of these timelines, and the Bidder's ability to accommodate them).

Please refer to Appendix "C" for a CHEC pre-approved deployment schedule, which is complete with meter delivery schedules. The Installer shall develop and maintain an installation schedule to ensure installations are completed on time and on budget without interfering with the meter-reading schedule.

4.2 Approved Hours of Installation (C)

Meter installations are to take place between the hours of 8:30 a.m. to 4:30 p.m., Monday to Friday. In special circumstances, extended hours of 8:00 a.m. to 8:00 p.m. and/or Saturday work may be considered by CHEC members if required to accommodate the timelines as communicated within Section 2.1 *Key Dates*. No Meter installation is to take place on statutory holidays observed by CHEC.

The Installer shall develop and maintain an installation schedule to ensure installations are completed on time and on budget without interfering with the meter-reading schedule. The Installer can modify the work schedule with permission of CHEC members to best meet installation goals and project milestones.

4.3 CHEC Deployment Territory (C)

Maps for CHEC's service territories have been provided in Appendix "B" to better illustrate the service territory within which the residential Smart Meter deployment will take place. It is anticipated that all Smart Meter installations being procured through this RFP will take place within these territories.

4.4 Installation Volumes (C)

CHEC projects that of the required 110,000 residential Smart Meter installations, 101,937 will be installed by the successful Bidder (with the exception of any reported safety concerns).

In addition to the following table, CHEC has provided within Appendix "B" the cycle volumes for certain of CHEC member's service territory.

Single Phase Meters	Indoor		Outdoor	
	S-base	P/A-base	S-base	P/A-base
Centre Wellington	377	0	4,609	0
Collus	23	32	11,512	339
Innisfil	50	0	11,740	233
Lakefront	1,273	621	5,919	5
Lakeland	649	49	6,416	118
Midland	180	45	5,203	45
Orangeville/Grand Valley	444	94	7,727	96
Orillia	262	305	9,000	0
Parry Sound	442	9	2,185	15
Rideau St. Lawrence	569	821	3,155	90
Wasaga	52	12	9,653	130
Wellington North	381	77	2,025	276
Westario	175	107	14,400	0

4.4.1 Electrical Contractor

CHEC shall provide a qualified Electrical Contractor to complete repairs to customer plant deemed necessary based on the identified safety concerns.

4.5 CHEC Meter Deliveries (C)

Westario Power will require that the Installer manage the meter inventory on their behalf, and release meters to the field service staff from an Installer managed Meter Depot location. The Pricing and Compliancy spreadsheet allows for bidders to enter pricing for this requirement.

The remaining CHEC members are also interested in this service as well, and Bidders are asked to provide pricing for their service territories as well. In the event that CHEC members (with the exception of Westario Power) decide not to implement this option, the following meter depot locations will be used. Under this arrangement, for the duration of this deployment, meter installers will be required to pick up, and drop off, their inventory at the following address, between the hours of 7:30 am to 5:00 pm:

CHEC Utility Member	Meter Depot Location
Centre Wellington Hydro Ltd:	**730 Gartshore Street, Box 217** **Fergus, ON N1M 2W8**
COLLUS Power Corp:	**43 Stewart Road, Box 189** **Collingwood, ON L9Y 3Z5**
Innisfil Hydro Distribution Systems Ltd:	**2073 Commerce Park Drive** **Innisfil ON L9S 4A2**
Lakefront Utilities Inc:	**207 Division Street, Box 577** **Cobourg, ON K9A 4L3**
Lakeland Power Distribution Ltd:	**5 - 45 Cairns Cres.** **Huntsville, ON P1H 2M2**

Midland Power Utility Corporation:	**16984 Highway 12, P.O. Box 820 Midland, ON L4R 4P4**
Orangeville Hydro Limited and Grand Valley Energy Inc:	**400 'C' Line, Box 400 Orangeville, ON L9W 2Z7**
Orillia Power Distribution Corporation:	**360 West Street South Orillia, ON L3V 6J9**
Parry Sound Power Corporation:	**125 William Street Parry Sound, ON P2A 1V9**
Rideau St. Lawrence Distribution Ltd:	**985 Industrial Road, Box 699 Prescott, ON K0E 1T0**
Wasaga Distribution Inc:	**950 River Road, Box 20 Wasaga Beach, ON L9Z 1A2**
Wellington North Power Inc:	**290 Queen Street West, Box 359 Mount Forest, ON N0G 2L0**
Westario Power Inc:	**24 Eastridge Road Walkerton, ON N0G 2V0**

All pick-up and delivery of meters by the Installer shall be at the designated facility for the term of this contract unless otherwise agreed upon. Field Service Personnel shall pick up new meters and equipment and return the removed meters, in the new cartons, once daily to a designated location provided by CHEC. No meter shall be returned without an associated transaction record and must be in actual cartons from new installs duly marked.

The Installer will be responsible for all meters from time of signing out of inventory/warehouse until successfully installed. Information regarding inventory in the Installer's custody shall be provided to CHEC upon request.

Note: For deployment within the outlying areas, arrangements will be made between the successful Bidder, and CHEC members, to minimize travel time for the Installers. For pricing purposes, Bidders should assume minimal impact to the work day (i.e. meter pick-up and drop-off will not impact the 8:30 am to 4:30 pm work day).

Section 5: Bidder Information

5.1 Experience (I)

i. How many years has the Bidder been in business?
ii. How long has the Bidder been providing installation services?
iii. The Bidder should describe their primary line of business and the percentage of business derived from the installation of meters.
iv. The Bidder should describe the organization and provide an organization chart of the team or department that would have specific resources used in the deployment of AMI. (Include the number of personnel assigned to installation services and project management of the AMI installation.)
v. Identify and describe any AMI/AMR project where the installation schedule has been delayed as compared to the original Statement of Work per the contract when signed and describe the causes, current status and plans to address the delay(s). (If you lack AMI/AMR experience please provide for the most comparable projects you have completed to date).

5.2 Company Size and Location (I)

What is the current size (number of employees), turnover rates for last three (3) years, and location(s) of the Bidder's company?

5.3 Financial Statement (I)

What is the current financial condition of the Bidder's company? Provide supporting documentation and annual reports for the last three years. If the company is privately held, supply sufficient information to document the company's financial status.

5.4 Subcontractors (I)

Does the Bidder intend to subcontract any component, service or support requested in this RFP? If so, indicate which components, services or support and identify the subcontractors.

5.5 References (I)

Provide a list of at least three (3) references (contact names and phone numbers) from companies that have used the Bidder's proposed services in the past three (3) years. Please indicate the number of meters installed and type (gas, water or electric).

5.6 Litigation (I)

Bidder will indicate if there are any anticipated or pending lawsuits or any litigation within the past five (5) years or bankruptcy filings within the past ten (10) years.

5.7 Environmental Policy (I)

CHEC recognizes environmental protection as a guiding principle and key component of sound business performance. CHEC is committed to providing quality customer service in a manner that ensures a safe and healthy workplace for our employees and minimizes our potential impact on the environment. We not only operate in compliance with, but also strive to exceed all relevant federal, provincial, and municipal environmental legislation; and we will strive to use pollution prevention and environmental best practices in all we do.

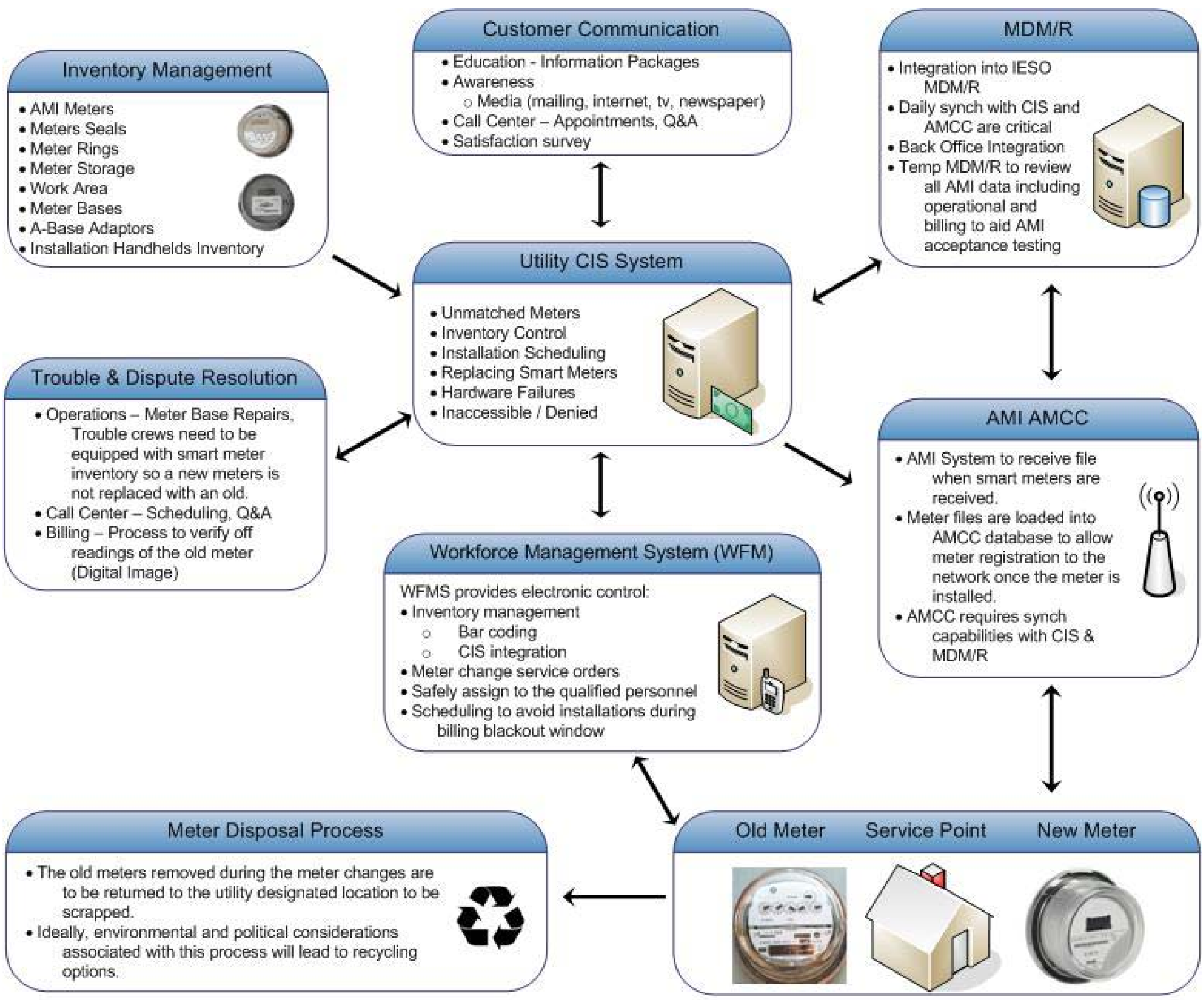
Bidder should indicate if they have a written environmental policy statement, whether the policy statement includes a commitment to continual improvement of environmental performance, whether the company has documented environmental performance objectives/targets and implementation plans, and what their three most significant environmental performance objectives/targets are. In addition, Bidders should describe the extent to which employees understand, accept, and share the environmental values of the company, and how the company uses environmentally friendly products in its day-to-day operations.

Section 6: Installation Services

With the execution of this province wide mandate, we would stress the importance of providing our customers with the highest level of customer service possible. Figure 3 is a high level view of the work flow process that encompasses the Smart Meter Installation process. Bidders will note the requirements for:

- Proper receipt and inventory of meters
- Change out order creation
- Change out order completion
- Workforce management system to update CIS when orders are completed
- Inventory update to MDR system
- Need for bar coding or digital image of changed meter to prevent disputes
- Ongoing reading of Smart Meter system
- Ongoing maintenance of inventory in MDR

Figure 3: High Level Work Flow of Installation Process



6.1 Installation Overview (C)

The Smart Meter installer will be responsible for installing Smart Meters on all single phase, network and self contained meter installations for all residential and small commercial (under 50 kW) locations. The Contractor will not be required to install any transformer rated installations or polyphase meters. The total number of non-transformer rated customer electric meter installations being procured through this RFP can be found in Section 4: *Project Overview*.

CHEC will perform upgrade or repair to electric services found to require this during the Smart Meter inspection or installation process. Installer will notify CHEC as rapidly as practical when such requirement poses a hazard to field workers. Bidders will describe notification procedures and method for tracking the status of such sites.

- **All Field Personnel must be well groomed, and in full uniform with the required CHEC member utility photo identification.** Installer will not issue daily assignments to Field Personnel who do not comply with this policy, and the appropriate disciplinary action should follow.
- All Field Personnel will strictly adhere to CHEC inventory control processes, including the proper use of any associated Workforce Management System.
- All Field Personnel will ensure that any required ancillary meter supplies (seals, rings, etc) are acquired prior to beginning the days' work (to ensure travel time is minimized).
- Meter installations are to take place between the hours of 8:30 am to 4:30 pm Monday to Friday. No meter installations are to take place on statutory holidays observed by CHEC member utilities.
- CHEC will provide meter seals and other security hardware to be placed on the meter by the Contractor when installing the meter. A-to-S Base meter adapters will be provided by CHEC for A-Base meter change outs.
- As part of providing exemplary customer service, the Bidder is expected to handle customer complaints that are related to installation services and provide customer assistance to resolve issues resulting from installation negligence to the satisfaction of CHEC, ensuring all claims are reported to CHEC. Claims not resolved after 10 days should be reported to the appropriate CHEC member utility for resolution.

6.1.1 Minimum Competencies (C)

Before installing meters the Installer shall ensure the Field Service Personnel are customer service oriented, have flexible work hours and are bonded, and the Installer shall maintain a process to ensure these requirements are met.

The Installer shall operate within specific procedures and operating conditions in adherence with procedures and training that CHEC will provide. Upon conclusion of the CHEC utility specific training, it will be the Installer's responsibility to ensure that new employees receive the same level of training as those employees which receive the training through CHEC.

6.1.2 Suggested Installation Procedure (CI)

The Installer shall follow the following process for the installation of all Smart Meters:

i. The Field Service Representative (FSR), as a minimum, will visit the site as the first attempt to install the Smart Meter.
ii. Prior to installation, FSR will knock on the door prior to removing the meter to advise the customer of the work to be performed and pending power outage.
iii. If the first attempt is not successful due to inability to access the meter, the FSR shall visit

the customer site a second time on a different day, at a time of day at least (2) hours different from the first visit, to perform the Smart Meter installation.

iv. If necessary, a third visit attempt shall be made by the FSR.
v. If necessary, the Contractor shall also attempt to reach the customer by telephone, to schedule access to the meter.
vi. If necessary, a second telephone attempt shall be made.
vii. If three (3) visits and two (2) phone contacts have been exhausted without successful access to the meter, the Installer may declare the account non-installable and refer it to CHEC for resolution.
viii. All customer contact, interaction and communications shall meet CHEC standards.
ix. The customer shall be accommodated with a scheduled appointment with a specific day and time within a 1 hour window arranged and scheduled by the Installer, through their call centre which will be open between the hours of 8:00 am and 7:00 pm.
x. The utility will provide a list of known customers on Medic Alert as per the Control Centre list.
xi. Installer will deliver upon completion of meter change an information "Drop" package for the customer.
xii. Installer will ensure the install site is left "clean" (i.e. under no circumstances is the customer site to be left littered with any installation associated debris)
xiii. Should an incident occur at the property (i.e. Broken meter jaws), the contractor shall remain at the property until the contract electrician or CHEC staff can arrive at the property.

When every meter on a route has either passed the field installation operating test or been declared non-installable by Installer, that route will be declared ready for Route Acceptance.

With regards to the installation procedure above, Bidders are requested to discuss:
a) concurrence with suggested procedure
b) concurrence with suggested definition of non-installable account
c) PPE utilized by Field Service Personnel

6.1.3 Installer Vehicles (C)

Installer will provide Field Personnel a vehicle to be used for installation services. The requirement for a uniform fleet of vehicles is to minimize the call centre traffic associated with customer inquiries related to the appearance of Field Service Personnel. Field Service Personnel are expected to maintain vehicles in respectable condition (i.e. reasonably clean, presentable and without excessive damage) as well as perform and document a daily vehicle safety check. Vehicles will be properly marked to indicate the company providing services. The meter installation vehicles are to be capable of carrying a minimum of 60 boxed meters (15 boxes). Removed meters are to be placed in the boxes that the new meters were shipped in and returned to the utility designated location.

The Installer shall be responsible for all related parking fines and parking fees through the course of the Agreement.

CHEC members shall provide their corporate logo and "Under Contract" signage, which must be affixed to all vehicles used by the Contractor. The Contractor may display its own corporate logo as approved by CHEC. Preference will be given to vehicles that are otherwise unmarked (ie. Display no other significant signs or marking such as a rental agency logo).

6.2 Pre-Installation Inspection (CI)

The pre-installation inspection shall include knocking on the door of the customer premise to determine if the site is occupied, and to inform occupants of the imminent, brief power interruption. Meter Installers will utilize the appropriate PPE and Equipment (including, but not limited to, arc/flame resistant uniforms (Category 2), meter installer identification, etc.) at all times.

The pre-installation inspection shall discern whether:

- The work site is unsafe to complete the assigned task (unsafe meter base, confined space, etc.)
- There is tampering or energy diversion evident at the meter site
- The existing physical equipment and installation do not conform to applicable codes
- The existing meter and installation is transformer rated.
- An electrical hazard may arise upon installation of the Smart Meter

If ANY of the above five (5) conditions exist, the Contractor shall perform no work at the site, but shall notify the Installer Project Manager, who shall notify the CHEC contract Administrator. It is possible that the pre-installation will fail to detect a hazard, such as tension (frost pull) on the underground secondary service conductor that will move broken meter socket jaws when the meter is removed. The Installer shall comply with CHEC procedures that apply if, at any time during the Smart Meter process, a serious hazard arises.

6.2.1 Tampering (C)

The Installer is responsible for reviewing electric metering facilities for obvious signs of tampering and interference, including jumpers, stopped meters (if not disconnected), un-metered load on the line side of the meter, damage caused by apparent attempts to open the meter, or any other situation where tampering/interference appears to have been involved. If the Installer suspects tampering or diversion, no work (or further work) shall be performed at that site. The Installer shall notify CHEC on a daily basis of all power diversion, tampering or interference-related situations that might impact revenues to CHEC.

Any meters that are scheduled to be replaced and are disconnected using disconnect sleeves or have a Programmable Service Interrupter unit installed will be re-installed by the Installer after the meter change unless the utility directs otherwise. All meters that are disconnected with sleeves, must be installed on the new Smart Meter with tabs on the bottom lugs only to ensure the meter will continue to act as a communication hop.

6.2.2 Power Diversion (I)

During the process of installing Smart Meters, CHEC wishes to discover meter installations (if any) where there is meter tampering and/or energy diversion. As such, a financial incentive of an agreed to amount per proven occurrence will be paid to the Installer for each verified instance of meter tampering and/or power diversion.

Bidders are requested to provide any information pertaining to this or other incentive programs which are thought to ensure high service levels from Field Service Personnel.

6.3 Scheduling & Coordination (I)

Coordination among the flow of materials, installer labour, customer response/acceptance, and CHEC member utility data updates is a principal determinant of whether the Smart Meter installation proceeds on-time and within budget. A well-coordinated project can run smoothly and finish on time. No unusual mandatory work rules or wage constraints apply to the work solicited in this RFP.

The Bidder should propose normal work hours to CHEC for its approval. Installers are to be available for work on evenings and weekends and for special-need installations. The Bidder should be prepared to modify the work schedule to best meet installation goals and project milestones set by CHEC.

Bidders are requested to provide information regarding the manner in which work is assigned, including such details as number of outside installs per day assigned, number of indoor installs assigned per day, and the capabilities of the Bidder's WFM system with regards to routing, personnel qualifications to avoid assigning work to the wrong people/trucks, etc. The Installer shall provide a detailed deployment schedule that accomplishes CHEC's meter installation targets. The Installer is responsible to manage the installation schedule to ensure the satisfaction of CHEC. The Installer is responsible to design, propose, and possibly implement a plan to advance the installation services timeframe in the event that the project schedule is delayed in any way.

The Installer is responsible for responding to calls from CHEC members regarding the loss of service and other high priority problems associated with installations on an expedited basis. CHEC will do everything within its control to aid the progress of the Installer in meeting the goals of this Agreement. However, minor delays in productivity due to day-to-day operational issues management will occur and are considered typical and normal in the course of regular business. (ie. Software irregularities, computer downtime, wireless communications gaps or emergencies.)

6.4 Project Management (CI)

The Contractor shall designate a Project Manager who shall have the authority to handle and resolve any disputes or contractual issue with CHEC member utilities.

The Project Manager is expected to spend sufficient time on the project and the project site to identify any areas that are not fully meeting the stated requirements, and manage corrective actions to bring the results within said requirements.

The Project Manager's role will be to coordinate activities among the Contractor, the Smart Meter provider and the various functional areas within member utilities. Problem resolution will be high on the Manager's agenda. The Project Manager will maintain clearly defined levels of installation problem categories and associated escalation levels to facilitate quick recognition and resolution of problems. The Project Manager will involve CHEC utilities as appropriate to resolve issues in a timely manner.

Section 3.2 *Safety* and Section 6.1.1 *Minimum Competencies* requires that the meter installer's meet certain qualifications, and that the installation service provider provide CHEC members with certain documentation. The Project Manager will facilitate satisfaction of these requirements,

Bidders should provide suggested procedures for Problem Resolution / Problem Escalation.

6.4.1 Quality Assurance (I)

The Installer's policies/procedures shall include an integrated quality control / quality assurance program:

Bidders will describe the proposed approach to staffing the field deployment, including:

a. Positions to be filled by permanent employees of Bidder
b. Positions to be filled by temporary employees or contractors
c. Qualifications of employees or contractors
d. Training of employees or contractors
e. Strategy for monitoring the work quality of employees or contractors and correcting any encountered deficiencies

CHEC members understand that there may be several AMI deployments occurring concurrently across Ontario to accommodate the Provincial mandate, and requires the Bidders written acknowledgement that the appropriate staff will be dedicated to the requirements of the CHEC deployment.

6.4.2 Installation Field Audit (CI)

The Installer's Project Manager / Supervisor will conduct random audits of staff in the field to check for safety compliance as well as for the quality of work completed by the meter installers. The Contractor's Project Manager / Supervisor will, on a weekly basis, randomly check a minimum of 2% of the sites for quality control. All results are to be reported to CHEC on a weekly basis. Items to be audited include at minimum:

- Proper line and load wiring associations on bottom connected installations
- Identification of hot metering installations when a main switch exists at a service entrance and is supposed to provide isolation to the meter and it is actually on the load side of the meter
- Validation of crossed units, on multi-unit dwellings
- Work order data validation and transfer to each utility

6.4.3 Service Quality Standard (C)

All work shall be completed according to the agreed schedule using milestones. Checkpoints and corrective action on slipped timelines shall be assessed on an interval of duration no longer than (2) weeks.

In keeping with the stringent safety requirements of CHEC member utilities, as communicated herein, Bidders will strive for no less than zero preventable safety incidents and accidents.

Failure to report any safety incident or accident to a CHEC member utility will put the Contractor in breach of the Agreement and may disqualify them from competing for future service contracts and may result in the termination of the present Agreement without a notification period.

6.5 Workforce Management (WFM) System

The Workforce Management (WFM) system plays an integral role in the success of the project acting as the main system responsible for work order completion, project reporting and task management, and ensuring safety for meter installations. Due to the critical nature of the WFM, it is imperative that the 3rd party installation service provider be comfortable with the functionality of the WFM system. For this reason, CHEC will require that the Bidder provide their own WFM as part of their service package.

It is a fundamental requirement that this system is in place with a functional interface to CHEC member utility CIS systems prior to the start of deployment. CHEC is interested in the functionality provided as part of the WFM system; information will be requested as part of Section 6.5 *Workforce Management (WFM) System* and associated subsections. A compliancy statement is required which will have Bidder's acknowledge proficiency with an electronic WFM system, and a commitment to ensuring integration with CHEC members' back office systems prior to project commencement (as per Section 2.1 *Key Dates*). Bidders should include, with their submission, the file layouts that CHEC members would be required to interface their CIS system with.

Provided below are the billing systems that are currently in use at CHEC member utilities which the proposed WFM system will be required to interface with.

- Advanced (2.1)
- Harris (5.2.19)
- Harris Northstar (6.2.9)
- SAP (R3 v 4.6c)

CHEC will provide to the vendor, in electronic format, information concerning the locations that will require meter changes / installations (i.e. customer name and contact information, service location address and location number along with an expected completion date). By way of electronic WFM the Installer will add to this record, the final meter read from the mechanical meter at the time of removal. The Installer will also take a photograph of the old meter, showing its dials prior to removal. This photo will be date and time stamped and the file name recorded in the data record associated with the specific installation.

6.5.1 WFM System Overview (I)

Within the Pricing and Compliancy spreadsheet, CHEC has provided a tab labelled WFM_Functionality, within which Bidders are requested to submit information pertaining to their WFM system, specific to the different devices that may be utilized with the system.

Below we have provided an example of a completed WFM system functionality matrix. Bidders are requested to complete this spreadsheet for all devices that are compatible with the WFM software platform. In addition to acquiring the information regarding a variety of functionality, CHEC looks to understand any potential functionality differences between devices being offered as part of a solution. If multiple devices are possible CHEC utilities may opt to purchase more than one type of device. In this case it would be important to understand if any functionality is lost in moving from one device to another.

Completion of the chart may satisfy some of the following sections. However the following sections provide Bidders with the opportunity to supply additional supporting information which may differentiate their product.

Workforce Management (WFM) Functionality

WFM Functionality	WFM Bidder: Sample (S/O)	Add-On Cost
Devices		
Handheld	S	
Tablet	O	$1200/tablet
Signature tool	O	Standard with tablet
Touch Screen	O	Standard with tablet
Printing Capabilities	O	$600/print device
Connectivity		
Real Time	O	cost to interface
Batch upload (offline storage)	S	
Carriers		
Bell	S	
Rogers	S	
Telus	S	
Multiple Network Roaming	O	$300/comm card
Utility RF	NA	
Other	NA	
Existing Utility Interfaces		
T&W	S	
SAP	S	
SPL	O	cost to interface
Other	S	
Forms		
Template only	S	
Customized	S	
Other	NA	
Reporting		
Fat Client	No	
Thin Client	Yes	
Canned	S	
Customized	S	
Safety	S	
Inventory	S	
Completed vs. Schedule	S	
Route Summary	S	
Problem Installs	S	
Other	S	programming fees
Operational Tools*		
Bar Code Scanner	S	
GPS Recording	S	
Camera	NA	
GPS Tracking of Workers	NA	
Scheduling		
Automated dispatch	S	
Dispatching based on qualifications & Equipment	S	
Map based dispatching	O	
Street level routing	O	
Other	NA	

Bidders are required to complete chart for their WFM product. If more than one product is offered, copy the columns as required.

Bidders are required to specify an S or an O to represent standard functionality vs. optional functionality. If the optional functionality is available only at an incremental cost, this must be specified.

NA may be used to represent Not Available.

***For Operational Tools, please indicate in the associated documentation whether this functionality is integrated with the WFM device, or whether they are separate tools.**

6.5.2 Dispatching (CI)

In support of the priority which CHEC members place on safety, CHEC is interested in the ability to assign worker qualifications to their field staff to assist in the dispatching of orders to only the personnel with the qualifications required to complete the work. This may be achieved through assigning qualifications to staff, or toolsets to trucks, or any other of a variety of methods. Details should be provided regarding all the safety features inherent to the WFM system.

Bidders are asked to provide detailed information regarding the dispatching of work orders. The manner in which work orders are sorted/listed (i.e. by customer, location, schedule, etc) is critical in realizing efficiencies with the assignment of field services.

If GPS capabilities are inherent to the system, and are integrated into the dispatch process, Bidders are asked to provide explanation, and screen shots of the views that are possible for the dispatcher. In addition to the mapping of orders, CHEC members are interested in accessing the real time location of their workers to assist in the completion of on demand requests (i.e. service disconnect / reconnect, outage restoration, etc). Details regarding this functionality are requested.

In addition to the manner in which the dispatcher accesses information, Bidders are asked to explain the ease with which the field service worker (and any associated options) can sort work. If GPS capabilities exist, and are integrated with the sorting of work while in the field, screen shots of the views possible for the field service worker are requested.

6.5.3 Data Management & Integrity (I)

The Installer shall record and retain the meter identification information and the register read of the removed meter, the meter identification information and the register read of the installed Smart Meter using a handheld WFM system equipped with a barcode reader.

The Installer shall maintain an effective process to assure the quality of the electronic data records and transactions. All field data shall be pre-filled on orders. The Installer shall place emphasis on quality data management from the beginning of the training, and will remain responsible for correcting errors in data collected during the installation process.

Data quality (including Meter Reads) shall be accurate 99.9% of the time over the course of the project. The Installer shall collect data from specified collection locations and transfer data in a specified electronic file format for use by CHEC in accordance with a schedule that will be provided by the utility.

6.5.4 WFM Handheld Device (I)

CHEC would like to understand the device being utilized by the contractor. Information should include format of device (tablet, PDA, laptop, phone, etc.), how many orders per day the handheld device can manage (i.e. how many can be downloaded), and what the expected daily battery life is of the device.

6.5.5 Installation Hours (i.e. WFM Charging) (CI)

CHEC's policy for installation hours are that installations should be occurring between the hours of 8:30 am and 4:30 pm. CHEC prefers that there are no evening installs. Saturday installs are acceptable with proper planning (minimum 1 week notice) and staffing of the call center. This should be a last resort for installation backlog, so as not to inconvenience customers. Installer would be required to provide a minimum number of installers in this instance to ensure that it is a productive day (i.e. CHEC members will have to pay overtime to warehouse staff).

6.5.6 Digital Imaging (CI)

The handheld Workforce Management Equipment must be able to take a picture with a resolution no less than 3 Mp of the removed meter. The Installer will take a photograph of the old meter, showing its dials. This photo will be date and time stamped and the file name recorded in the data record associated with the specific installation.

Digital imaging is performed to mitigate the risk associated with Dispute Resolution. If the WFM system allows for read validation which might be used in conjunction with the Digital Imaging process, Bidder should provide details.

6.5.7 GPS (CI)

In addition to installing the meter, capturing the LAN ID and Meter ID data from the barcode on the installed meter, and the start read, CHEC desires to update service location information by having the Bidder capture the GPS co-ordinates of the installed endpoint. Where meters are located in basements or in areas where satellite signal may not be possible, the closest co-ordinates will be collected once communication has been established. Details (including GPS accuracy) are requested regarding this functionality.

6.5.8 Inventory Control (CI)

Given the volume of daily meter installations that will be performed, maintaining accurate control of inventory will be critical. All sealed meter deliveries will be sent to the CHEC location and loaded into inventory via an import into CIS.

Daily workflows will need to be established that have an assigned point of contact for the installation vendor to verify and sign-out the meters required each day for installation in the field. At the end of each day or at start of the next shift, the same point of contact will verify the meters that were not installed are recorded in inventory ensuring adequate controls are in place to manage the assets.

Managing the inventory of essential hardware is an important step in keeping the installation process moving while controlling costs.

i. The Workforce Management system will be capable of utilizing bar code scanning for recording newly deployed meters.
ii. Bidders will describe methods used to track inventory of all essential ancillary supplies needed to support the deployment including any associated smart meter devices and installation tools, meter seals, meter rings, meter adaptors, security devices, etc. Bidders should provide details on how their company will ensure that accurate data is provided back to CHEC members and their back office systems.

6.6 Reporting Requirements (CI)

The CHEC Project Manager will hold weekly meetings together with the Installer's Project Manager to review status, identify problems, and plan resolution. The Installer shall provide reporting (as per following subsections) to support these meetings. Where possible, reports should be generated from the WFM system, made possible by the daily data transfers identifying sites visited and completed.

Following is a sample of items that might be included in these reports:

i. Safety Issues;
ii. Bidders will describe installation problem categories and escalation levels, identifying the point at which the CHEC Project Manager will become involved;

iii. Inventory status;
iv. Installers will provide daily data transfers identifying sites visited and completed and providing work order data;
v. Bidders should supply automated reports regarding success/failure of daily installation targets;
vi. The Installer shall report progress, including numbers and percentages of meters installed, attempts to complete the installation process, appointments scheduled and completed and other pertinent installation data to CHEC on a weekly basis (if project plan timeline has been affected, the Installer will provide their plan which will put them back on schedule according to the originally submitted schedule);
vii. It is expected that the successful Bidder will invoice based on the data in the WFM system.

Bidder's should provide detailed information regarding the reporting functions that are possible through their WFM or other systems.

The Installer will provide all required equipment, along with the trained staff. The Installer shall be required to report all relevant data from the field to the CHEC Installation Coordinator. This includes, but is not limited to meter exchanges that cannot be completed because of access, physical space limitations, or safety reasons.

6.6.1 Reporting: Beginning of the Project (C)

In addition to any other data and reporting requirements outlined, the following report / information will be required at project commencement:

The Bidder will provide CHEC with a Project Plan that indicates the number of meter installers per week for the duration of the project as well as the meters to be installed per week. The Plan shall include contingency plans in the event the installation numbers fall behind the milestone schedule.

6.6.2 Reporting: Daily Reports (C)

In addition to any other data and reporting requirements outlined, the following reports and information will be required on a daily basis through the duration of the project:

The Bidder will identify, report and resolve unsafe conditions on a daily basis or as they are identified according to established safety policies, and report all tampering / interference related situations that might impact revenues, to CHEC on a daily basis.

6.6.3 Reporting: Weekly Reports (C)

In addition to any other data and reporting requirements outlined, the following reports and information will be required at weekly interval through the duration of the project:

The Bidder will provide CHEC members with project plan updates which include number of meters installed to date, and number of meters remaining to be installed. If behind schedule, Action Plans will be identified that are being used to bring the installation schedule back on track.

In addition, the Bidder shall provide details related to any identified unsafe conditions, safety issues, customer diversions, tampering.

6.6.4 Reporting: Bi-Weekly Reports (C)

In addition to any other data and reporting requirements outlined, the following reports and information will be required at bi-weekly intervals through the duration of the project:

The Bidder will provide CHEC member utilities with an invoice indicating: The number of meters installed, the number of identified and utility validated power diversions, the number of identified and utility validated unsafe meter installation sites, the month end invoice shall indicate the number of meters that didn't comply with the month-end target milestone installations.

6.7 Service Level Agreements (I)

Bidders should provide their standard Service Level Agreements, citing such measurable performance indicators as:

i. Outside Urban installation per week
ii. Inside Urban installation per week
iii. Installation Error rate
iv. Customer Claim rate

6.8 Installation Warranties (I)

The Bidder must state terms on guarantee of workmanship for all installation work performed under this contract.

6.9 Meter Disposal (I)

CHEC will be utilizing a Meter Disposal Vendor to properly, and in an environmentally sound manner, discard of the redundant meters. Should the Bidder desire to provide a Meter Disposal Labour rate, a line item has been added to Pricing Option 1 for this purpose. The Labour that would be required for this service would potentially be for the separation of glass covers from meters, and organization of meter packing supplies (cardboard, Styrofoam packing etc.) into the appropriate bins that would be provided by the Meter Disposal Vendor. CHEC would provide the work space for this service to be performed.

6.10 Water Meters (I)

NOTE: While this section does include an indicator (I), this section is not considered mandatory. There is no requirement that Bidders provide a response to this section.

Certain of CHEC members are interested in replacing existing water meter infrastructure with equipment which will be compatible with the AMI system being deployed. In all likelihood this will require a two stage implementation beginning with the replacement of existing remotes with radio modules. Upon conclusion of the replacement of exterior remotes, the utility will begin replacing meter heads where required. It is expected that the two stages will occur at different times due to the variation in work requirements.

CHEC members for which this work is applicable are interested in synergies and possible cost savings that may result through some combination of work schedules. As the decision regarding this work will be made through a separate procurement, the information that is requested here is purely informational and will not form part of the evaluation being conducted for the purposes of determining the best fit Installer for deployment of electric smart meters.

Information that may contribute to the future procurement includes:

i. Bidder experience with water projects (information submitted may include "suggestion" as to how to best structure work flow to minimally impact the electric deployment, while possibly realizing synergies and cost efficiencies)
ii. Bidder qualifications for water projects
iii. Bidder references for water projects

Bidders that are interested in being considered for this future work are required to:

a. Provide an email to the CHEC contact listed in Section 2.4 Submission of Bids. The email need only provide contact information and expression of interest in the future procurement process. This will ensure that interested bidders are included in the future process.
b. Provide the information requested in this section as part of their response. **As noted in this Section, responses will not be evaluated as part of the decision regarding Electric Smart Meter Deployment Installation Services.**

6.11 Ancillary Services (I)

CHEC members are interested in having the successful Bidder warehouse the AMI meters which have been received into utility inventory. The Pricing and Compliancy spreadsheet allows for bidders to provide pricing for this service through the Pricing Option 1 tabs, under the Ancillary Services section.

Westario Power **will require** this service. While the remaining CHEC members may not ***require*** this service, they are interested in possible efficiencies that may be realized through having the vendor provide this service (i.e. relaxed time of return for installers due to absence of time restrictions associated with the utility managed meter depot). Bidders are asked to provide pricing for warehousing services for both service areas.

CHEC members would like to reiterate to Bidders the importance of clearly specifying any conditions/assumptions that have contributed to their pricing. CHEC members have provided line items within the pricing tabs which may appear repetitive (i.e. GPS, Disposal labour, Imaging process, inventory management, etc), however this has been done intentionally to provide vendors with the flexibility to provide incremental pricing for all required services.

Section 7: Customer Communications

7.1 Call Centre Services (I)

Installer will be responsible for customer communications associated with gaining access to the customer's meter. CHEC recognizes that some accounts, despite extensive effort by Installer, may be non-installable for any of many reasons. CHEC members accept responsibility for installing smart meters at these non-installable accounts. Bidders will describe the customer communications plan, including;

i. Call Centre Services Overview (including hours of operation, and policies/procedures)
ii. Customer contact methods/strategies
iii. Appointment management (management of multiple sequential (unsuccessful until the last) customer contacts)
iv. Steps in achieving successful completion of Smart Meter installation
v. Definition of an non-installable account
vi. Customer claims administration
vii. Record keeping and coordination with CHEC Customer Service (CHEC member utilities are interested in understanding the tracking of Service Quality Indicators (SQIs) which may include (but not limited to) such indicators as inbound/outbound calls, appointments attempted/made, complaints, call waiting period, etc.)

Call operations shall be maintained from 8:00 a.m. to 7:00 p.m., Monday to Friday, and shall have a provision for taking calls using an automated method outside of the regular operating hours. CHEC recognizes that their agents may take calls, other than those for the purpose of appointments, once a phone number is provided to the customer. CHEC wishes the Contractor to transact only those calls related to the appointments to be fielded by their staff, and the operator for disposition shall direct all others to CHEC.

The Contractor shall provide in detail:

- The scripting for communicating with customers by phone
- A means of managing the collected customer information and appointments (i.e. managing ongoing coordination and customer communications related to the appointment and meter exchange by the Contractor)
- The fee structure for managing the customer communications for the expressed purpose of collecting appointment data

7.1.1 Communications Materials (I)

CHEC requires that communications materials be provided to the customer by their meter installers when the meter is inaccessible contain the phone number of the Contractor for future follow-up. The Contractor shall manage inbound phone communication to secure appointments for Smart Meter installations using a professional and courteous protocol that shall be approved by CHEC.

7.1.2 Customer Contact (I)

Each meter installer shall be responsible for customer communications associated with gaining access to customer meter. Meter installers will be provided with communications materials to be distributed to customers as part of the meter installation process.

Prior to beginning the meter exchange, each meter installer shall attempt to notify each customer by knocking on the front door and/or ringing the doorbell and waiting a minimum of (1) minute for a response. If the customer does respond, the Installer shall inform the customer of the meter exchange and short power interruption according to the standardized script provided by CHEC. If the customer does not respond, the Installer shall proceed with the installation of the Smart Meter.

7.1.3 Customer Information (CI)

Each meter installer shall provide each customer with communication materials as provided by CHEC, either in person, in the mailbox or through the mail slot. These materials are not to be left where they are readily visible to passers-by or may blow away or become damaged (i.e. rain damage).

7.1.4 Customer Complaints and Claims Administration (CI)

The Installer shall have a procedure to process and manage customer claims, arising from the provision of the Services pursuant to this Agreement, which will successfully resolve issues in a timely manner. All claims shall be reported to CHEC once the Installer has been made aware of the incidence. Claims outstanding over (10) days are to be reported to CHEC for resolution. The Installer shall have full accountability for customer claims and complaints, especially for the response to initial reports of half or full power outage following a Smart Meter change. This accountability applies regardless of the time of call and may fall outside business and work hours. CHEC crews and resources are prepared to aid the Installer in a resolution based on the initial findings of Field Staff if the call ends up being systemic rather than an oversight on the part of the Contractor. Additional compensation shall not be provided by CHEC to meet the Installer's obligations for after-hour response and site visits that are required to mitigate customer complaints.

7.2 Pre-Canvassing Service (I)

Pre-Installation Customer Information Packages are to be delivered to customers approximately 2 weeks before the scheduled meter replacement date. Customer Contact and Information Packages would be provided by CHEC.

As an option, Bidders that are able to provide input based on experience regarding suggested processes for Customer Communications that may take place prior to deployment are requested to do so. If possible, the Bidder should provide any marketing material that they may have used in the past that was found to be effective.

Section 8: Contract Terms and Conditions

8.1 General

This Agreement covers the general conditions under which the work shall be performed.

Bidder shall be aware and acknowledges that the work to be performed may be on or within close proximity to electrical apparatus that may be energized at normal potential and with normal current carrying capacity during the course of the work. This may involve the equipment or facilities being worked on directly, or equipment or facilities adjacent to the actual devices and location being worked on.

Bidder will under no circumstances replace anything except single phase meters.

8.2 Information to Contractors

Bidder represents that it has carefully examined the specifications and requirements of the municipality(s) having jurisdiction in the work location(s) and any other authorities having jurisdiction, and has thoroughly familiarized themselves with all permit, inspection and other requirements of all of these agencies and authorities.

Bidder will not rely solely upon any information or representations made or furnished by CHEC respecting the nature of the site conditions, the work to be performed or the quality of any materials to be used.

8.3 Approvals

Bidder shall work closely with the authorities having jurisdiction. Bidder shall satisfy all authorities on specific concerns on work permits. No permit costs have been included in this Agreement. Should the need for any permits arise, Bidder will invoice CHEC for the costs thereof.

8.4 Sub-Contractors

Bidder shall set out herein, all Sub-Contractors to be employed in the performance of the Agreement. No other Sub-Contractor shall be employed without the approval of CHEC.

8.5 Officials in Charge, Personnel, Employment Conditions

Bidder shall identify in Schedule “A”, prior to commencing work, a work site manager (the person on the job) who will be in charge of the work and all work sites, as well as an office official (officer, principle, or senior manager) at his central place of business who will be responsible for the work.

CHEC’s key contacts are also identified in Schedule “A”.

Bidder shall take every step to minimize a change of site manager during the course of the work, but when necessary, Bidder will make such change with an individual of similar or greater capability.

Bidder will provide conditions of employment in accordance with the Occupational Health and Safety Act, and the Employment Standards Act and their latest revisions, and any other statutory requirements in force and effect.

Bidder hereby agrees that no person shall be employed who is unfit to do the work or anyone unskilled to do the work assigned to him. Persons under the influence of intoxicating drugs or beverages shall be declared unfit.

Bidder agrees that for the purpose of the work to be undertaken, they will not discriminate in the hiring and implementation of labour against any person's gender, race, national origin, colour or religion.

8.6 Work Protection

Work protection from electrical hazards, where required, shall be applied for prior to beginning work and shall be consistent with the Electric & Utilities Safety Association's Protection Code, and upon review and acceptance by Bidder, CHEC requirements. Protections shall be surrendered at the end of each working day. In general, daily requests shall be available during CHEC normal working hours only.

Signalling and traffic protection shall be done according to the Occupational Health and Safety Act, the Highway Traffic Act, and CHEC requirements.

Only competent personnel shall work within the ten feet limit of approach for apparatus energized over 750 volts. CHEC Manager of Engineering and Maintenance shall have the sole discretion to determine such competence, but Bidder will assume full liability in respect of any such personnel, even if approved of by CHEC. Equipment, tools, and protective clothing shall be in accordance with the Electric Utilities Safety Act, the Occupational Health and Safety Act, and other authorities having jurisdiction.

8.7 Site Housekeeping

During the performance of the work, Bidder shall ensure that the work site is kept as neat and orderly as possible, in keeping with the nature of the work in progress. When work is interrupted for any length of time, or at the completion of the work, all waste material shall be removed and tools, equipment and surplus material shall be removed or stored or secured in a neat and safe fashion.

8.8 Term

The Agreement will terminate as per the agreed to contract dates. The Agreement may be extended on terms mutually agreeable to the parties.

8.9 Training and Safety

Before beginning installation of smart meters, all Bidder installers must receive the following training:

- E&USA Training for residential smart meter changes. Proof of training must be provided and approved by CHEC.
- CHEC Health and Safety orientation
- Work procedures and workforce management orientation

Bidder shall comply with all CHEC safety rules, when Bidder has reviewed and accepted such rules.

8.10 Schedule

Bidder shall submit, at such times as may reasonably be requested by CHEC, schedules which shall show the order in which it is proposed to do the work, with dates showing commencement and completion of the various parts of the work.

8.11 Public Relations

Bidder shall respect private property and do whatever necessary to prevent damage to landscaping, buildings, fences and other appurtenances on private property and where damage results will make restoration to the pre-damaged state. Public lands on rights of way shall be restored to the satisfaction of the authority having jurisdiction.

8.12 Identification

Bidder vehicles must be properly identified with the company name. Bidder employees must carry proper identification at all times.

8.13 Materials and Labour

Unless otherwise stipulated, the lump sum price or prices quoted in this Agreement shall include the furnishing of all of the Bidder designated supplied materials, supplies and equipment and the providing of all labour, construction tools and equipment, utility and transportation services necessary to perform and complete all the work required under this Agreement.

All designated material, major or minor, supplied by Bidder must be approved by CHEC prior to its installation. Any material supplied by Bidder and installed without CHEC approval will be replaced at Bidder's expense. Co-ordination of the delivery of materials shall be by Bidder. No claims will be considered due to late deliveries.

8.14 Working Hours

Unless otherwise stated, all labour and services under this Agreement will be performed during the hours of 8:30 am - 4:30 pm local time Monday through Friday, excluding statutory holidays (except for telephone call answer services). If for any reason CHEC requests Bidder to furnish any such labour or services outside of the hours of 8:30 am - 4:30 pm local time Monday through Friday, or on statutory holidays, any overtime or other additional expense occasioned thereby, such as repairs or material costs not included in this Agreement, will be billed to and paid by the appropriate CHEC member utility.

8.15 Taxes

CHEC agrees to pay the amount of any new or increased Canadian taxes or governmental charges upon labour or the production, shipment, sale, installation, or use of equipment or software which become effective after the date of this Agreement. If CHEC claims any such taxes do not apply to transactions covered by this Agreement, CHEC will provide Bidder with a tax exemption certificate acceptable to the applicable taxing authorities. CHEC to the extent required by applicable law, may retain and remit any withholding taxes on behalf of Bidder and provide evidence of that to Bidder. CHEC shall not be required to make any "gross up" payment to Bidder to compensate Bidder for such withholding.

8.16 Insurance Obligations

Bidder shall, at its own expense, carry and maintain in force at all times from the effective date of the Contract through final completion of the work the following insurance. It is agreed, however, that Bidder has the right to insure or self-insure any of the insurance coverage's listed below:

(a) Commercial General Liability Insurance to include contractual liability, products/completed operations liability with a combined single limit of CDN $5,000,000 per occurrence. Such policy will be written on an occurrence form basis.
(b) If automobiles are used in the execution of the Contract, Automobile Liability Insurance with a minimum combined single limit of CDN $5,000,000 per occurrence. Coverage will include all owned, leased, non-owned and hired vehicles.
(c) Where applicable, "All Risk" Property Insurance, including Builder's Risk insurance, for

physical damage to property which is assumed in the Contract.
(d) Workers Safety Insurance Board Insurance Coverage A - Statutory limits.

Prior to the commencement of the Contract, Bidder will furnish evidence of said insurance coverage in the form of a Memorandum of Insurance, and warrants that such coverage will be maintained for the duration of the Agreement, and that proof of maintenance will be routinely supplied.

Bidder will not issue coverage on a per project basis.

8.17 Hazardous Substances, Mould and Unsafe Working Conditions

8.17.1

CHEC has not observed or received notice from any source (formal or informal) of (a) Hazardous Substances or Mould, either airborne or on or within the walls, floors, ceilings, heating, ventilation and air conditioning systems, plumbing systems, structure, and other components of the Site, or within furniture, fixtures, equipment, containers or pipelines in a Site; or (b) conditions that, to CHEC's knowledge, might cause or promote accumulation, concentration, growth or dispersion of Hazardous Substances or Mould on or within such locations.

8.17.2

If any such materials, situations or conditions, whether disclosed or not, are in fact discovered by Bidder or others and provide an unsafe condition for the performance of the work or Services, the discovery of the condition will constitute a cause beyond Bidder's reasonable control and Bidder will have the right to cease the work or Services until the area has been made safe by CHEC or CHEC's representative, at CHEC's expense. Bidder will have the right to terminate this Agreement if CHEC has not fully remediated the unsafe condition within sixty (60) days of discovery.

8.17.3

CHEC members represent that they have not retained the Bidder to discover, inspect, investigate, identify, prevent or remediate Hazardous Substances or Mould or conditions caused by Hazardous Substances or Mould.

8.18 Warranty and Limitation of Liability

8.18.1

Bidder will have all work performed by appropriately trained and experienced personnel in a workmanlike manner consistent with industry standards and applicable law. Bidder will replace or repair any work Bidder provides under this Agreement that fails within the warranty period (one) 1 year because of defective workmanship or Bidder supplied materials, except to the extent the failure results from CHEC negligence, or from fire, lightning, water damage, or any other cause beyond the control of Bidder. This warranty applies to all work Bidder provides under this Agreement, whether or not manufactured by Bidder. The warranty is effective as of the date of installation.

8.18.2

The warranties set forth herein are exclusive, and Bidder expressly disclaims and CHEC expressly waives all other warranties, whether written or oral, implied or statutory, including but not limited to, any warranty of workmanship, construction, merchantability or fitness for a particular purpose, with respect to the services, equipment, and materials provided hereunder. Bidder will not be liable for any property damage, personal injury, loss of income, emotional distress, death, loss of use, loss of value, adverse health effect or any special, incidental, indirect, speculative, remote, consequential, punitive, or exemplary damages, arising from, or relating to, this limited warranty or its breach.

8.18.3

Bidder makes no representation or warranty, express, implied or otherwise, regarding Hazardous Substances or Mould. Bidder will have no duty, obligation or liability, all of which CHEC expressly waives, for any damage or claim, whether known or unknown, including but not limited to property damage, personal injury, loss of income, emotional distress, death, loss of use, loss of value, adverse health effect or any special, consequential, punitive, exemplary or other damages, regardless of whether such damages may be caused by or otherwise associated with defects in the Services, in whole or in part due to or arising from any investigation, testing, analysis, monitoring, cleaning, removal, disposal, abatement, remediation, decontamination, repair, replacement, relocation, loss of use of building, or equipment and systems, or personal injury, death or disease in any way associated with Hazardous Substances or Mould.

8.19 Indemnity

Bidder agrees to indemnify and hold CHEC and its agents and employees harmless from all claims for bodily injury and property damages to the extent such claims result from or arise under Bidder’s negligent actions or willful misconduct in its performance of the work required under this Agreement, provided that such indemnity obligation is valid only to the extent (i) CHEC gives Bidder prompt notice in writing of any such claims and permits Bidder, through counsel of its choice and Bidder’s sole cost and expense, to answer the claims and defend any related suit and (ii) CHEC gives Bidder the authority and reasonable assistance and access to all applicable information in its possession, at Bidder’s expense, to enable Bidder to defend such suit. Bidder will not be responsible for any settlement without its written consent, which consent shall not be unreasonably withheld or delayed. Bidder will not be liable for loss or damage caused by the negligence of CHEC or any other party or such party’s employees or agents. This obligation will survive termination of this Agreement. Notwithstanding the foregoing, CHEC agrees that Bidder will not be responsible for any damages caused by Mould or any other fungus or biological material or agent, including but not limited to property damage, personal injury, loss of income, emotional distress, death, loss of use, loss of value, adverse health effect or any special, consequential, punitive, exemplary or other damages, regardless of whether such damages may be caused by or otherwise associated with defects in the Services.

8.20 Limitation of Liability

8.20.1

Subject to: (1) Bidder’s obligations under the above indemnity (s. 8.19), (ii) a breach of its confidentiality or privacy obligations, (iii) breach of applicable law; or (iv) intentional or willful misconduct, in no event will Bidder be liable for any special, incidental, indirect, speculative, remote, consequential, punitive or exemplary damages, whether arising out of or as a result of breach of contract, warranty, tort (including negligence), strict liability, mould, moisture, indoor air quality, or otherwise, arising from, relating to, or connected with the services, equipment, materials, or any goods provided hereunder.

8.20.2

Notwithstanding anything to the contrary herein, Bidder’s total liability arising out of or as a result of its performance under this agreement will not exceed the amount of this agreement.

8.21 Excusable Delays

Bidder will not be liable for damages caused by delay or interruption in Services due to fire, flood, corrosive substances in the air, strike, lockout, dispute with workmen, inability to obtain material or services, commotion, war, acts of God, the presence of Hazardous Substances or Mould, or any other cause beyond Bidder's reasonable control (the "Force Majeure Event") provided that Bidder: (i) promptly notifies the other Party immediately and in detail of the commencement and nature of such a cause; (ii) promptly develops a workaround strategy if one is reasonably available; and (iii) uses all commercially reasonable efforts to render performance in a timely manner utilizing to such end all resources reasonably required in the circumstances, including obtaining supplies or services from other sources if same are reasonably available and to otherwise resume service to the applicable standard. A failure by a sub-contractor or other agent to perform shall only be considered a Force Majeure Event if the failure by that sub-contractor or agent to perform is due to a Force Majeure Event suffered by that sub-contractor or agent and such sub-contractor or agent is taking the same actions as are required by Bidder under this Section in respect of a Force Majeure Event. The benefit of this section shall not apply to the performance or an obligation which is thirty (30) or more days in default. In the event of any such delay, date of shipment or performance will be extended by a period equal to the time lost by reason of such delay.

8.22 Dispute Resolution

With the exception of any controversy or claim arising out of or related to the installation, monitoring, and/or maintenance of fire and/or security systems, the Parties agree that any controversy or claim between Bidder and CHEC arising out of or relating to this Agreement, or the breach thereof, will be settled by arbitration, conducted in accordance with the Arbitration Rules of the Canadian Commercial Arbitration Center. Any award rendered by the arbitrator will be final, and judgment may be entered upon it in accordance with applicable law in any court having jurisdiction thereof. Either party can terminate for cause without the obligation to engage in dispute resolution, mediation or arbitration.

8.23 Acceptance of Contract

This proposal and the pages attached will become an Agreement upon signature above by Bidder and CHEC. The terms and conditions are expressly limited to the provisions hereof, including Bidder's General Terms and Conditions attached hereto, notwithstanding receipt of, or acknowledgment by, Bidder of any purchase order, specification, or other document issued by CHEC. Any additional or different terms set forth or referenced in CHEC's purchase order are hereby objected to by Bidder and will be deemed a material alteration of these terms and will not be a part of any resulting order.

8.24 Miscellaneous

8.24.1

This Agreement represents the entire Agreement between CHEC and Bidder for the work described herein and supersedes all prior negotiations, representations or Agreements between the Parties related to the work described herein.

8.24.2

None of the provisions of this Agreement will be modified, altered, changed or voided by any subsequent Purchase Order or other document unilaterally issued by CHEC that relates to the subject matter of this Agreement. This Agreement may be amended only by written instrument signed by both Parties.

8.24.3

This Agreement will be governed by the law of the province where the work is to be performed.

8.24.4

Any provision or part of this Agreement held to be void or unenforceable under any laws or regulations will be deemed stricken, and all remaining provisions will continue to be valid and binding upon Bidder and CHEC, who agree that this Agreement will be reformed to replace such stricken provision or part thereof with a valid and enforceable provision that comes as close as possible to expressing the intention of the stricken provision.

8.24.5

CHEC may not assign its rights or delegate its obligations under this Agreement, in whole or in part, without the prior written consent of Bidder. Bidder may assign its right to receive payment to a third party.

8.24.6

Bidder will provide services in accordance with the attached work scope documents and the terms and conditions herein, which form a part of this Agreement.

8.24.7

The parties are independent contractors and no other relationship is intended. Nothing herein shall be deemed to constitute either party as an agent, representative or employee of the other party, or both parties as joint venturers or parties for any purpose to create a fiduciary relationship between the parties. Neither party shall act in a manner that expresses or implies a relationship other than that of an independent contractor. Each party shall act solely as an independent contractor and shall not be responsible to third parties for the acts or omissions of the other party. Neither party will have the authority or right to represent or obligate the other party in any way except as expressly authorized by this agreement.

8.24.8

If Bidder is delayed in its performance of the work due to the delayed performance or non-performance of CHEC or its suppliers, CHEC shall notify Bidder one (1) week in advance. In the event Bidder is notified (1) one week in advance, Bidder shall relieve CHEC of all costs except for the following: In the event Bidder incurs any costs in retaining staff or recruiting and staffing a new position as a result of the delay then CHEC will reimburse Bidder at its actual documented costs incurred plus 10%. Bidder shall invoice CHEC no more than weekly for such reimbursement and CHEC shall pay such invoices within the terms of this Agreement. All such invoices will itemize the costs incurred and proof will be provided to the extent possible.

8.25 Terms of Payment

Subject to Bidder's approval of each CHEC member utility's credit, payment terms are as follows:

Progress Payments: Bidder will invoice monthly for all materials delivered to the job site or to an off-site storage facility and for all installation, labour, and services performed, both on and off the job site. CHEC agrees to pay the full amounts invoiced, less holdback, upon receipt of the invoice at the address specified by CHEC. Invoices not paid within thirty (30) days of the invoice date are past due and accrue interest from the invoice date to the date of payment at the rate of one percent (1%) per month, compounded monthly.

Holdback: CHEC will not withhold, as holdback, a greater percentage than is withheld from CHEC under a prime contract, if applicable. CHEC will pay all holdback to Bidder within 30 days after Bidder's work is substantially complete.

Suspension of work: If Bidder, having performed work per Agreement requirements, does not receive payment within thirty (30) days after submission of a Bidder invoice, Bidder may suspend work until CHEC provides remedy unless CHEC provides evidence disputing such amount is owing.

8.26 Work by Others

8.26.1

Unless otherwise indicated, the following items are to be furnished and installed by others: electric wiring and accessories, all in-line devices (including but not limited to flow tubes, hand valves, orifice plates, orifice flanges, etc.), pipe and pipe penetrations including flanges for mounting pressure and level transmitters, temperature sensors, vacuum breakers, gauge glasses, water columns, equipment foundations, riggings, steam tracings, and all other items and work of like nature. Automatic valve bodies and dampers furnished by Bidder are to be installed by others.

8.26.2

Services Bidder will provide under this Agreement specifically exclude professional services which constitute the practice of architecture or engineering unless specifically set forth by CHEC. CHEC or Owner will specify all performance and design criteria that Bidder will follow in performing work under this Agreement. If professional design services or certifications by a design professional related to systems, materials, or equipment is required, such services and certifications are the responsibility of others.

8.27 Delivery

Delivery of equipment not agreed on the face hereof to be installed by or with the assistance of Bidder will be F.O.B. at Bidder's factory, warehouse, or office selected by Bidder. Delivery of equipment agreed on the face hereof to be installed by or with the assistance of Bidder will be C.I.F. at site of installation.

8.28 Damage or Loss

Bidder will not be liable for damage to or loss of equipment and software after installation.

8.29 Termination

A party may terminate this Agreement for cause if the other party defaults in the performance of any material term of this Agreement, or fails or neglects to carry forward the work (in the case of Bidder) in accordance with this Agreement, after giving the other party written notice of its intent to terminate. If the defaulting party has not, within seven (7) business days after receipt of such notice, remedied such deficiencies, the other party may terminate this Agreement.

8.30 Changes in the Work

CHEC, without invalidating the Agreement, may direct the Contractor to perform extra work or make changes in the work, provided that all changes or additions form an inseparable part of the contracted work. The contractor shall make such changes or additions only after receipt of written instructions to do so from CHEC. If such changes or additions cause an increase or decrease in the cost of the Agreement, or in the time required to complete the Agreement, an equitable adjustment shall be made and the Agreement shall be modified accordingly by a Change Order in writing.

When a change is ordered, CHEC and the Contractor shall execute a change order before any change order work is performed. Any increase or decrease in the contract price and the time required for the completion of the contract work due to a change order shall be specifically set out in the change order. All terms and conditions contained in the Agreement shall be applicable to change order work. The amount of any increase or decrease shall be added to or subtracted from the contract price as appropriate.

8.30.1

A Change Order is a written order signed by CHEC and Bidder authorizing a change in the work.

8.30.2

CHEC may request Bidder to submit proposals for changes in the work, subject to acceptance by Bidder. If CHEC chooses to proceed, such changes in the work will be authorized by a Change Order.

8.31 Acceptance of the Work

CHEC designated representative will determine if any work has not been performed in accordance with this Agreement.

Upon receipt of notice by Bidder that the work is ready for final inspection and acceptance, CHEC will make such final inspection and issue acceptance within five (5) business days (except for work performed in the first thirty (30) days of the Agreement, in which case it shall be ten (10) business days). Acceptance will be in a form provided by Bidder, stating that to the best of CHEC's knowledge, information and belief, and on the basis of CHEC's on-site visits and inspections, the work has been fully completed in accordance with the terms and conditions of this Agreement. If CHEC finds the work unacceptable due to non-compliance with a material element of this Agreement, which non-compliance is due solely to the fault of Bidder, CHEC will notify Bidder in writing within the five (5) business days (or ten (10) business days, as applicable) setting forth the specific reasons for non-acceptance. Failure to respond shall result in cancellation of the Agreement. Any payment then made will be based on proration, per unit, quantities of acceptable work performed, less costs assessed by CHEC for correction of deficiencies and noted issues. Nothing in this Section 8.31 will be construed to require that CHEC indemnify and hold harmless the Bidder from claims and costs resulting from Bidder's negligent actions or willful misconduct.

8.32 Confidentiality and Privacy

"Confidential Information" means all information relating to either Party or to such Party's business, products, sales, customers, trade secrets, technology or financial position to which access is obtained or granted hereunder, which when disclosed to the other Party is marked or otherwise designated as confidential, provided, however, that Confidential Information shall not include any data or information which: (i) is or becomes publicly available through no fault of the other Party; (ii) is already in the rightful possession of the other Party prior to its receipt from the other Party as evidenced by documentation; (iii) is independently developed by the other Party as evidenced by documentation; (iv) is rightfully obtained by the other Party from a third party whose lawful right to provide such data or information is evidenced by documentation; (v) is disclosed with the written consent of the Party whose information it is; or (vi) is disclosed pursuant to a Canadian court order or other Canadian legal compulsion.

8.33 Definitions

8.33.1

"Hazardous substance" includes all of the following, and any by-product of or from any of the following, whether naturally occurring or manufactured, in quantities, conditions or concentrations that have, are alleged to have, or are believed to have an adverse effect on human health, habitability of a Site, or the environment: (a) any dangerous, hazardous or toxic pollutant, contaminant, chemical, material or substance defined as hazardous or toxic or as a pollutant or contaminant under state or federal law, and (b) any petroleum product, nuclear fuel or material, carcinogen, asbestos, urea formaldehyde, foamed-in-place insulation, polychlorinated biphenyl (PCBs), and (c) any other chemical or biological material or organism, that has, is alleged to have, or is believed to have an adverse effect on human health, habitability of a Site, or the environment.

8.33.2

"Mould" means any type or form of fungus or biological material or agent, including mould, mildew, moisture, yeast and mushrooms, and any mycotoxins, spores, scents, or by-products produced or released by any of the foregoing. This includes any related or any such conditions caused by third parties.

8.33.3

"Covered Equipment" means the equipment covered by the Services to be performed by Bidder under this Agreement, and is limited to the equipment included in the respective work scope attachments.

Request for Proposal

Operational Data Store
RFP 2008-1114

November 14, 2008

Cornerstone Hydro Electric Concepts

Table of Contents

Section 1: Background

1.1 Introduction

To create a conservation culture in Ontario and make the Province a North American leader in energy efficiency, the Government has taken action to facilitate a number of key initiatives, including the introduction of flexible, time-of-use pricing for electricity, and a target reduction in Ontario's energy consumption of 5% by 2007.

The attached documentation sets out the procedural and technical requirements for the submission of proposals to Cornerstone Hydro Electric Concepts (CHEC), for its Operational Data Storage (ODS) requirements as per the enclosed specifications; as well as the substantive contractual terms that govern the relationship between parties upon award of the contract.

CHEC members have been working collaboratively through the planning and preparation stages for the Smart Meter Initiative. CHEC is an association of electricity distribution utilities modeled after a cooperative to share resources and proficiencies as the Ontario electricity industry continues its transformation.

The mission of CHEC is to be recognized as the premier LDC Cooperative in the province, by meeting or exceeding member expectations through the sharing of services, opportunities, knowledge and resources. The values of CHEC include the sharing of resources, both intellectual and technical, enabling members to deliver value to their customers and shareholders ensuring competitiveness in the marketplace. Together the mission and value statements represent lofty but attainable goals for CHEC members. Collaboratively CHEC represents over 110,000 residential end points in Ontario and is comprised of the following member utilities:

Centre Wellington Hydro Ltd.
COLLUS Power Corp.
Grand Valley Energy Inc.
Innisfil Hydro Distribution Systems Ltd.
Lakefront Utilities Inc.
Lakeland Power Distribution Ltd.
Midland Power Utility Corporation
Orangeville Hydro Limited
Orillia Power Distribution Corporation
Parry Sound Power Corporation
Rideau St. Lawrence Distribution Ltd.
Wasaga Distribution Inc.
Wellington North Power Inc.
Westario Power Inc.

1.2 Provincial Context for Project

As part of its energy conservation effort, the Ontario government has made a commitment to replace all existing meters (5 million) with smart meters by 2010. Phase One utilities have fulfilled their commitments to install 1 million smart meters by Dec 31, 2007 which assisted the government in exceeding their interim goal of 800,000 by Dec 31, 2007. Focus now shifts to the Phase Two implementation of a Smart Meter Network.

The underlying premise behind the provincial mandate to install these meters is to educate customers on their consumption habits and implement new rate structures that will encourage load shifting and conservation of energy, thereby reducing the requirement for increased power generation capabilities. To this end, the province, by way of the Independent Electricity System Operator (IESO), will be implementing a centralized Meter Data Management / Repository to aggregate utility data from the multiple AMI systems being implemented across Ontario. The IESO has created validation rules, and synchronization processes to control data and ensure that data is complete and suitable for billing.

It should be noted that CHEC members fully support this endeavour on behalf of the IESO and the province of Ontario, and that the interests of the RFP document are not related to those of the IESO and the centralized MDM/R. The Operational Data Storage requirements discussed herein are for the purpose of storing AMI Data being collected by CHEC's AMI systems, for which there is no provision in the centralized system to store and further utilize to implement operational efficiencies that will now become possible through the implementation of this new metering infrastructure.

1.3 CHEC's Approach to Smart Metering

With respect to the Provincial government's Smart Metering Initiative, CHEC has taken a collaborative approach to becoming educated on this mandate by working with other Ontario utilities and advocacy groups. CHEC hopes to evaluate Bidders as objectively as possible with the end goal of selecting the best-fit provider for an ODS, thereby allowing CHEC members to achieve their goals, as well as those of the provincial Smart Meter mandate.

Along with satisfying the provincial mandate of measuring "how much electricity a customer uses each hour of the day, and to use that data to charge customers an energy price that varies depending on when the electricity was consumed" (OEB Smart Meter Plan; January 26, 2005; page i); CHEC members will also implement the Smart Meter Network to improve overall efficiency within each members respective service territory.

CHEC would like to reiterate their support for the IESO MDM/R system that is being implemented, and that the utilities will look to the ODS to support their needs for the introduction of efficiencies that become possible through the use of Operational data that is available through the AMI system. Due to the possibility that the centralized system may one day accommodate these needs, and in keeping with the utility's desire to minimize duplication in utility infrastructure, combined with the relative infancy of Operational Data Storage systems, the utilities will procure a system that is established in the Application Service Provider (ASP) model, allowing the system to grow with the utility needs, but also provide flexibility with regards to term; in the event that the centralized system is able to accommodate the operational needs as well as billing requirements, the utilities would support (and move to) the IESO model.

1.4 Smart Meter Terminology

For the purposes of this procurement process, and within this Request for Proposal document, CHEC has opted to utilize the terminology as defined by the Ministry of Energy in their *Functional Specification for an Advanced Metering Infrastructure Version 2* (dated July 5, 2007), Section 3, *Definitions.* For reference, this document has been included herein as Appendix "A".

1.5 Other Terms

1) ***MDM/R:*** Within this document the acronym MDM/R has been used in reference to the centralized Meter Data Management / Repository that is owned and operated by the Independent Electricity System Operator (IESO). Currently the IESO is working to integrate Smart Meter Data from systems that were installed in Phase One of the Ontario Smart Meter Initiative.
2) ***ODS:*** Within this document the acronym ODS will be used in reference to the Operational Data Storage Services being sought in (potentially) a temporary capacity for the purposes of auditing and validating smart meter data until such time that the centralized repository is in place. At that time CHEC members will make a business decision whether or not to continue utilizing the ODS based on the functionality that is available in ODS compared to that currently in place with the MDM/R. For example, at this time it is not clear whether MDM/R will be used to store operational information. If CHEC members are able to implement efficiencies as a result of the operational data being received from the installed AMI systems, it may be in CHEC members' best interests to continue utilizing ODS.

3) ***Bidder*** shall refer to the vendor proposing a solution to this RFP document.
4) ***Vendor*** shall refer to the successful Bidder. The term Vendor will be used when stating future requirements, to be performed only by the successful Bidder.

1.6 Key Dates

Below is the expected timeline that CHEC will be following during the evaluation of available ODS solutions. CHEC reserves the right to adjust these dates as needed. All Bidders will be notified if any of the following dates are altered. As can be seen, it is the intention of CHEC members to make their decision by January 30, 2009.

Dates of Significance

RFP released by CHEC:	**November 14, 2008**
Bidder Response with Intention to Bid:	**November 21, 2008**
Final Questions Due:	**November 28, 2008**
Answers to Questions:	**December 5, 2008**
Closing Time (RFP Due):	**3:00pm EST December 12, 2008**
Vendor Presentations:	**January 5 - 9**
RFP Decision:	**January 30, 2009**

Section 2: Instruction to Bidders

2.1 Bid Documents

This Request for Proposals (RFP), establishes the system products and services that CHEC members wish to acquire. This bid document is the basis upon which CHEC seeks firm proposals from selected Bidders and upon which proposals will be evaluated. The documents are:

1) This RFP (a .pdf document), including Appendices that are integral to it.
2) CHEC_ODS_RFP_PricingFunctionality_Nov2008.xls, a Microsoft Excel workbook. This file allows for entry of pricing information, as well as confirmation of compliancy with the required regulations, and will heretofore be referred to as the Pricing Spreadsheet.

2.1.1 Pricing and Compliancy Spreadsheet

The Pricing spreadsheet will allow for the Bidder to enter their pricing information in a standard format, as well as allow the Bidder to attest to their product's functionality. As per Section 2.4 *Proposal Format Instructions*, any hard copies of the pricing submission should be submitted in a separate envelope, marked "PRICE OFFER".

The following tabs are included within the Pricing and Compliancy Spreadsheet:

1) ODS_Functionality: This tab requires completion by the Bidder, and will act as their product functionality statement providing detailed information on product capabilities.
2) Pricing_Option1_ASP: This tab requires completion by the Bidder
3) Pricing_Option2: This tab is optional. If the Bidder feels that a pricing format apart from that provided in the Pricing_Option1_ASP tab will better represent their product offering, they may complete the Option 2 tab. **NOTE: In the event that the bidder chooses to complete Pricing Option 2, the utilities will still require a completed Option 1 tab.**

2.2 Intention to Bid

Recipients of this RFP are asked to inform CHEC of their intention to bid by completing the template form found in Section 2.19 *Proposal Forms*, and by submitting this form by the date shown in Section 1.6 *Key Dates*. Recipients that express intention to bid will be included in all correspondence (if any) during the bidding process. Please provide full contact information and expression of intention via the provided form to the CHEC member contact as per instruction in Section 2.19.1 *Intention to Bid Form*.

2.3 Submission Requirements

1) A complete proposal will consist of an original and seven (7) copies of each of
   a) The proposal forms,
   b) The Bidder's Response document (including all associated attachments),
   c) Pricing spreadsheet: CHEC_ODS_RFP_PricingFunctionality_Nov2008.xls; a Microsoft Excel workbook,
   d) Accompanying the Bidder's Response document should be the proposal forms provided in Section 2.19 *Proposal Forms*,
   e) The required format of the Bidder's Response document is outlined in Section 2.4 *Proposal Format Instructions*,
   f) The Pricing and Compliancy spreadsheet will allow for the Bidder to enter their pricing information in a standard format, as well as allow the Bidder to attest to their product's functionality,
   g) A soft copy of all of the above forms and documents should also be provided on one CD.

2) The original hard copy shall be clearly identified as "ORIGINAL"; the remainder (i.e. seven copies) shall be marked as "COPY". In the event of discrepancy between the copies of the Response, the one marked "ORIGINAL" shall prevail. Each Bidder's Response shall consist of the required documents with the required number of copies of all commercial information, including pricing, terms and conditions and exceptions (if applicable). Faxed or late proposals will not be accepted. Proposals must be sealed and marked clearly quoting the proposal number referred to on the cover sheet of the proposal documents. The use of any means of delivery of a proposal shall be at the risk of the Bidder.
3) Any Bidder wishing to provide additional information other than what is requested in the proposal documents must place such additional information in a separate section marked Supplementary Information, as per Section 2.4 *Proposal Format Instructions*. Any Additional Information or any unsolicited value-added alternatives may, in CHEC's absolute discretion, be given due consideration, or not.
4) CHEC member utilities shall not be liable for, nor shall they reimburse any Bidder for costs incurred in the preparation of proposals, or any other services or samples that may be requested as part of the evaluation process.
5) The Proposal Forms shall be signed under the Corporate Seal of the Bidder, by the duly authorized signing officer(s). All submitted pages shall be initialled by such officer(s).

2.4 Proposal Format Instructions

Where information has been requested through this RFP, the Bidder's Response should clearly indicate the RFP section number that the Response pertains to. The Bidder's Response should be organized according to the following sections:

1) Section 1 of the proposal will contain the Bidder's Executive Summary, no more than two pages in length that introduces the Bidder and highlights key features of the proposal.
2) Section 2 of the Proposal **should be provided in a separate envelope which has been clearly marked "PRICE OFFER".** This section will contain the summary pages pertaining to the Price Offer, contained within the Pricing and Compliancy Spreadsheet. The Bidder's detailed itemized pricing information for all goods or services is to be contained within the Pricing Spreadsheet which is to be included with the Response in its entirety as well as within this section. Any alternative pricing offers may also be included within the Pricing Spreadsheet, by adding tabs as needed. All pricing shall be expressed in Canadian currency, exclusive of taxes. If your originating currency is not Canadian, the currency exchange that was used to calculate the price in Canadian currency is to be provided.
3) Section 3 of the proposal will contain the functionality statement that is included within the Pricing Spreadsheet as the following tab: ODS_Functionality.
4) Section 4 of the proposal will contain all requested information regarding the Bidder (CHEC RFP Section 4: *Bidder Company Information*) in the order presented in this document, with the numbering used in this document.
5) Section 5 of the Bidder's proposal will contain the requirements of Section 5 of this RFP Document (Section 5: *ODS Solution Technical Requirements*), in the order presented in this document, with the numbering used in this document.
6) Section 6 of the Bidder's proposal will contain any additional documentation that the Bidder decides to provide regarding their offering.

2.4.1 Proposal Format Example: Section 5

Within Section 5: *ODS Solution Technical Requirements* of the RFP, an indicator has been included with the subsection heading to indicate the requirement of the Bidder to provide information pertaining to the functionality of their product (with regards to the section requirements), or a statement of compliancy AND information pertaining to the functionality of their product with respect to the requirement of the section.

(I) When an (I) has been included with the section heading, CHEC members require Information regarding the proposed system's functionality, and the methodology utilized to satisfy the RFP requirement.

(C) When a (C) has been included with the section heading, CHEC members require a statement of compliancy from the Bidder. Within the Submission documentation, the Bidder is required to state the proposed product's compliancy with the requirement by stating Fully Compliant, Partially Compliant, or Not Compliant. In instances where the product is Partially Compliant, or Not Compliant, the Bidder is required to state their plans (complete with development time line) to bring their product into compliancy.

(CI) When a (CI) has been included with the section heading, CHEC members require both a statement of compliancy, and Information regarding the proposed system's functionality, and the methodology utilized to accommodate the RFP requirement.

The method with which the Bidder provides information and compliancy statements is detailed within the individual sections, as well as within the Pricing and Compliancy Spreadsheet.

SAMPLES of response for Section 5: *ODS Solution Technical Requirements*, demonstrating that the section numbering from this document is to be retained, and that each section should be included, and shall include within it a statement of compliance (which is also included in spreadsheet form in the Pricing and Functionality Spreadsheet).

5.5.6 Reporting: Custom Queries (C)

The ODS will be capable of executing custom queries to accommodate any areas where standard reports are not available.

Vendor's declaration of compliance: **Fully Compliant**

5.9 Scalability (CI)

The Bidder must describe its proposed ODS data model demonstrating the model's flexibility and scalability to deliver cumulative and interval metering over the next ten years. The system should be designed for a minimum of 250,000 customers, assuming 2 years of online interval data and 7 years off-line data storage. Please specify the methodology for data storage and retrieval.

Vendor's declaration of compliance: **Fully Compliant**

Vendor's Functionality Statement: The ODS system being proposed has been implemented in several deployments (in other markets) of 300,000+ meters, with the largest deployment being 500,000 meters. In addition to these live deployments, the system has been volume tested to more than 1.5 million meters. While these large deployments are all electric AMI deployments, we have deployed the system in some smaller cooperatives 80,000+ meters which are multi-commodity (electric, water, and gas). We believe that together, these experiences demonstrate the scalability required to be successful in the Ontario marketplace. References have been included which can speak to these experiences.

2.5 Adjustments / Substitutions

1) A proposal may be altered by a Bidder only by submitting another proposal at any time up to the Closing Time. Adjustments by telephone, facsimile, telegram or letter to a proposal already submitted will not be considered. The last proposal received by CHEC's designee shall supersede and invalidate all proposals previously submitted by the Bidder for this RFP.
2) During the period prior to the Closing Time, changes made by CHEC members to the proposal documents will be issued by CHEC to the Bidders as written addenda. The Bidder shall list in its proposal all addenda that were considered in the preparation of its proposal.
3) No substitutions or deviation from the Specifications, Proposal Form or General Conditions of Contract will be permitted without CHEC's approval in writing.

2.6 Complete Bid

Bidders are requested to submit bids that are complete and unambiguous without the need for additional explanation or information. CHEC members reserve the right to make a final determination as to whether a bid is acceptable or unacceptable solely on the basis of the bid as submitted, and proceed with bid evaluation (or not) without requesting further information from any Bidder. If CHEC members deem it desirable and in their best interest, CHEC may, in its sole discretion, request from any Bidder or Bidders additional information clarifying or supplementing any submitted bid.

2.7 Clarifications

Upon the issuance of this RFP to Bidders, and continuing through the submission date, all questions or other communications with CHEC shall be by email only:

chec@util-assist.com

CHEC members will respond to the question in writing, with both the question and response provided to each Bidder that has declared intention to bid. No response will be made to questions submitted after November 28, 2008.

2.8 Grounds for Disqualification

It is a requirement of this RFP document that Bidder's submitting proposals for evaluation complete the Pricing Spreadsheet including the ODS_Functionality tab and format their bid submission according to Section 2.4 *Proposal Format Instructions*. CHEC reserves the right to reject any incomplete bids (as per Section 2.6 *Complete Bid*).

NOTE: Where functionality (within the ODS_Functionality tab of the Pricing Spreadsheet) has been misrepresented, CHEC reserves the right to disqualify the Bidder from further evaluation of the RFP.

2.9 Post Bid Meeting

CHEC members reserve the right to invite any or all Bidders to make an in-person presentation regarding the proposed ODS solution. CHEC may request Bidder's assistance in arranging visits to other installations where Bidder has deployed the solution.

2.10 Withdrawal of Proposal

Bidders will be permitted to withdraw their proposal unopened after it has been submitted if such a request is received by the designee of CHEC in writing, prior to the Closing Time.

2.11 Bid Inconsistencies

Any provisions in Bidder's proposal that is inconsistent with the provisions of this Request for Proposals, unless expressly described in the proposal as being exceptions, are deemed waived by the Bidder. In the event the order is awarded to Bidder, any claim of inconsistency between the proposal and this RFP will be resolved in favour of this RFP unless otherwise agreed to in writing by CHEC.

2.12 Bidder's Statement of Understanding

By submitting a response to this RFP, Bidders acknowledge the following:

1) The Bidder acknowledges that it has carefully examined, understands and accepts the proposal documents, has carefully examined the requirements contained in the proposal documents and hereby submits an offer according to the requirements set forth in this proposal.
2) It is understood that this proposal, if it has not been withdrawn in accordance with Section 2, subsection 2.10 *Withdrawal of Proposal*, is irrevocable and shall remain open for acceptance by CHEC for a period of ninety (90) working days following the opening of the proposals.
3) It is further understood by the Bidder that if CHEC accepts its proposal, then the Bidder is bound by the Contract and agrees to provide the goods and/or services upon the terms and conditions of the Contract
4) The Bidder acknowledges and agrees that all quantities shown in the proposal documents are approximate only. Quantities may be subject to increase, decrease, or total deletion in the event that CHEC determines in its absolute discretion that such change is required.
5) While CHEC has used considerable efforts to ensure an accurate representation of information in this Request for Proposal, the information contained in this Request for Proposal is supplied solely as a guideline for Bidders. The information is not guaranteed or warranted to be accurate by CHEC, nor is it necessarily comprehensive or exhaustive. Nothing in this Request for Proposal is intended to relieve Bidders from forming their own opinions and conclusions with respect to the matters addressed in this Request for Proposal.

2.13 Proposal Evaluation

1) All proposals shall be opened after the Closing Time in the presence of CHEC's Representative or another individual designated to open the proposals by CHEC. The opening will not be public.
2) In determining the contract award, the lowest proposal will not necessarily be accepted, and CHEC reserves the right to accept or reject any or all proposals in its absolute discretion. Further, proposals may be accepted or rejected in total or in part.
3) The Evaluation Committee will review proposals and will then carry out interviews with selected Bidders for clarification as required.
4) It is anticipated that a written contract will be negotiated immediately after the successful Bidder has been notified. If a contract cannot be negotiated within thirty (30) days of notification, CHEC may, at its sole discretion at any time thereafter, terminate negotiations with that Bidder and either negotiate a contract with the next qualified Bidder or choose to terminate the Request for Proposal process and not enter into a contract with any of the Bidders.

2.14 Award of Contract

1) The Bidder acknowledges that CHEC reserves the right, privilege, entitlement and absolute discretion, and for any reason whatsoever to:
   a) Cancel this Request for Proposals at any time, either before or after the Closing Time;
   b) Accept a proposal which is not the highest scoring proposal submission, or reject a proposal that is the highest scoring proposal even if it is the only proposal received;
   c) Accept the proposal deemed most favourable to the interests of CHEC or that may provide the greatest value advantage and benefit to CHEC based upon but not limited to price, ability, quality of work, service, past experience, past performance and qualification;
   d) Accept or reject any and all proposals, whether in whole or in part;
   e) Award any part of any proposal; or
   f) Accept or reject any unbalanced, irregular, or informal proposals.
2) The Bidder acknowledges that CHEC will evaluate proposals using an internal scoring method as referenced in section 2.13 *Proposal Evaluation* and other criteria which CHEC deems relevant, even though such criteria may not have been disclosed to the Bidder. By submitting a proposal, the Bidder acknowledges CHEC's rights under this section and absolutely waives any right, or cause of action against CHEC and its consultants, by reason of CHEC's failure to accept the proposal submitted by the Bidder, whether such right or cause of action arises in contract, negligence, or otherwise.
3) Contract award, if any, will be communicated by written notification from CHEC to the successful Bidder. The successful Bidder, if any, in the presence of the designate, must sign the Contract Agreement in triplicate (3), within seven (7) Working Days of written notification of acceptance.
4) Bidders whose proposals have been rejected by CHEC will be notified within thirty (30) days of the award date.
5) The successful Bidder shall provide CHEC with a designated inside customer service representative. Any disputes and/or queries with respect to the Contract will be directed to the CHEC representative, whose decisions with respect to any matter under dispute shall be final and binding.

2.15 Freedom of Information

Proposals submitted to CHEC become the property of CHEC and, as such, are subject to the *Freedom of Information and Protection of Privacy Act*, R.S.O. 1990, c. F.31, as amended.

2.16 Ownership of Data

CHEC shall own all data collected by the AMI system, and subsequently stored by the ODS. Data collected and stored by the system shall not be used for any purpose without the approval of CHEC.

2.17 Proposal Evaluation Criteria

CHEC will evaluate proposals using an internal scoring method that weights various parameters to give the CHEC Smart Meter Team insight into the strengths of each proposal relative to CHEC's needs. CHEC's internal scoring method values the following proposal attributes (order of presentation does not reflect priority):

Figure 1 Proposal Evaluation Criteria

Proposal Evaluation Criteria	Section	% Total Points
Project Overview	3	
Bidder Information	4	
ODS Functionality	5	
General Data Management Requirements		
Performance Service Levels		
System Integration		
Meter Event Manager		
System Disaster Recovery Planning		
ODS System Reporting		
Scalability		
ODS System Security		
Perspectives expressed by reference utilities		
Section 3 through 5 inclusive:		**60%**
Pricing Weighting:		**40%**
Total		**100%**

Along with the Bidder's company information, and statements of understanding regarding the project, the answers to sections 3 through 5 will represent 60% of the total weighting of the RFP. Pricing submitted will represent 40% of the total weighting of the RFP. Bidders will be selected for further discussion based on the Team's judgment, developed using the scoring method. CHEC reserves the rights to alter its internal scoring method and to exercise whatever judgment it deems in the best interests of CHEC in selecting an ODS solution provider.

2.18 Payment

When the Vendor has completed all work in accordance with the terms of the contract documents, the Vendor shall submit to CHEC a request for final payment. The request for final payment shall constitute a waiver of all claims by the Vendor except for claims specifically listed in the request. CHEC will make payment within forty-five (45) days of receipt of a request for payment.

Vendor's submission of its request for final payment shall constitute its warrant that the Vendor has to the best of its knowledge fully completed all work included in the Contract and has fully paid for labour, materials, equipment, services, taxes and all other costs and expenses resulting from this Contract.

2.19 Proposal Forms

Within this section, there are two forms required for submission. The first form is found in Section 2.19.1 *Intention to Bid Form*; the intention of this form is to allow the vendor to provide a standard email Response to CHEC designee to notify CHEC of the Bidder's intent to respond to the RFP.

2.19.1 Intention to Bid Form

The procedure to be utilized for this form is to copy and paste the following content into an email, and send the email to:

chec@util-assist.com

according to the time line as established by Section 1.6 *Key Dates*.

INTENTION TO BID NOTIFICATION FORM

PROPOSAL NO. 2008-1114

Intention to Bid:
Please allow this email to represent "__Insert Company Name Here__" intention to respond to RFP 2008-1114.

Contact for communication regarding bid: ________________________________
Contact phone number: ________________________________
Contact email address: ________________________________

We acknowledge the requirement for our ODS solution to, at minimum, audit the performance of the installed AMI to assist CHEC in making certain the AMI meets the Ministry of Energy's minimum functional requirements as outlined in the document *Functional Specification For An Advanced Metering Infrastructure Version 2* (dated July 5, 2007). Our proposal will include the required compliance statements and documents to properly express our ability to meet these requirements. We also acknowledge the Submission Deadline is 3:00 PM Eastern Time on December 12, 2008.

2.19.2 RFP Submission Form

The procedure to be utilized for this form is to print the following pages to be included with the RFP submission, which should be addressed to:

Attn: Ms. Ruth Tyrell
CHEC Group
c/o Orangeville Hydro
400 C Line
Orangeville, ON L9W 2Z7

according to the time line as established by Section 1.6 *Key Dates*.

Cornerstone Hydro Electric Concepts

Proposal Number: **RFP 2008-1114**

FOR: OPERATIONAL DATA STORAGE SYSTEM & SERVICES

THIS PROPOSAL IS SUBMITTED BY:____________________

ADDRESS:

TELEPHONE: FAX NO.:

BIDDER G.S.T. No.:

PERSON(S) SIGNING ON BEHALF:____________________________(print)

POSITION(S) OF THE PERSON(S):_________________________________(print)

To CHEC, Hereafter called "Owner":

I/WE ____________________________________ the undersigned declare:

1. THAT no Person(s), Firm or Corporation other than the one whose signature(s) of whose proper officers and the seal is or are attached below has any interest in this proposal or in the contract proposed to be taken.

2. THAT this proposal is made without any connections, knowledge, comparison of figures or arrangements with any other company, firm or person making a proposal for the same work and is in all respects fair and without collusion or fraud.

   THE Bidder insures that no Owner and or employee of Owner, is, or has become interested, directly or indirectly, as a contracting party, partner, stockholder, surety or otherwise howsoever in or on the performance of the said contract, or in the supplies, work or business in connection with the said contract, or in any portion of the profits thereof, or of any supplies to be used therein, or in any monies to be derived there-from.

3. THAT the several matters stated in the said proposal are in all respects true.

4. THAT I/WE have carefully examined the requirement(s), as well as all the Instructions to Bidders, Project Overview, ODS Technology – Technical Requirements, proposal Forms, and Appendices relating thereto, prepared, submitted and rendered available by the Owner and hereby acknowledge the same to be part and parcel of any contract to be let for the work therein described or defined.

5. THAT I/WE do hereby propose and offer to enter into a contract to deliver all work as described or implied therein including in every case freight, duty, exchange, G.S.T. and P.S.T. in effect on the date of the acceptance of proposal, and all other charges on the provisions therein set forth and to accept in full payment therefore, the sums calculated in accordance with the actual measured quantities and unit prices set forth in the proposal herein.

6. THAT Addendum/Addenda No. ___ to ___ inclusive relate to the said contract and Bidder hereby accepts and agrees to the same as forming part and parcel of the said contract.

7. THAT additions or alterations to or deductions from the said contract, if any, shall be made in accordance with the prices stated in the Schedule of Items of Unit Prices in strict conformity with the requirements of the Contract.

8. THAT this offer is irrevocable and open to acceptance until the formal contract is executed by the awarded Bidder for the said requirement(s) or Sixty (60) working days, and unit prices for as long as stated elsewhere in the document, whichever event first occurs and that the Owner may at any time within that period without notice, accept this proposal whether any other proposal has been previously accepted or not.

9. THAT the awarding of the contract, by the Owner is based on this submission which shall be an acceptance of this proposal.

10. THAT I/WE also understand that the Owner reserves the right to accept or reject all or part of this proposal or any other and also reserves the right to accept other than the lowest proposal.

The undersigned affirms that he/she is duly authorized to execute this proposal.

BIDDER'S SIGNATURE AND SEAL:

NAME: ______________________________ ______________________________
(Please Print) (Signature)

POSITION: ______________________________

WITNESS
NAME: ______________________________ ______________________________
(Please Print) (Signature)

POSITION: ______________________________

(If Corporate Seal is not available, documentation should be witnessed)

DATED AT THE ____ THIS ________
(City/Town) (Day)

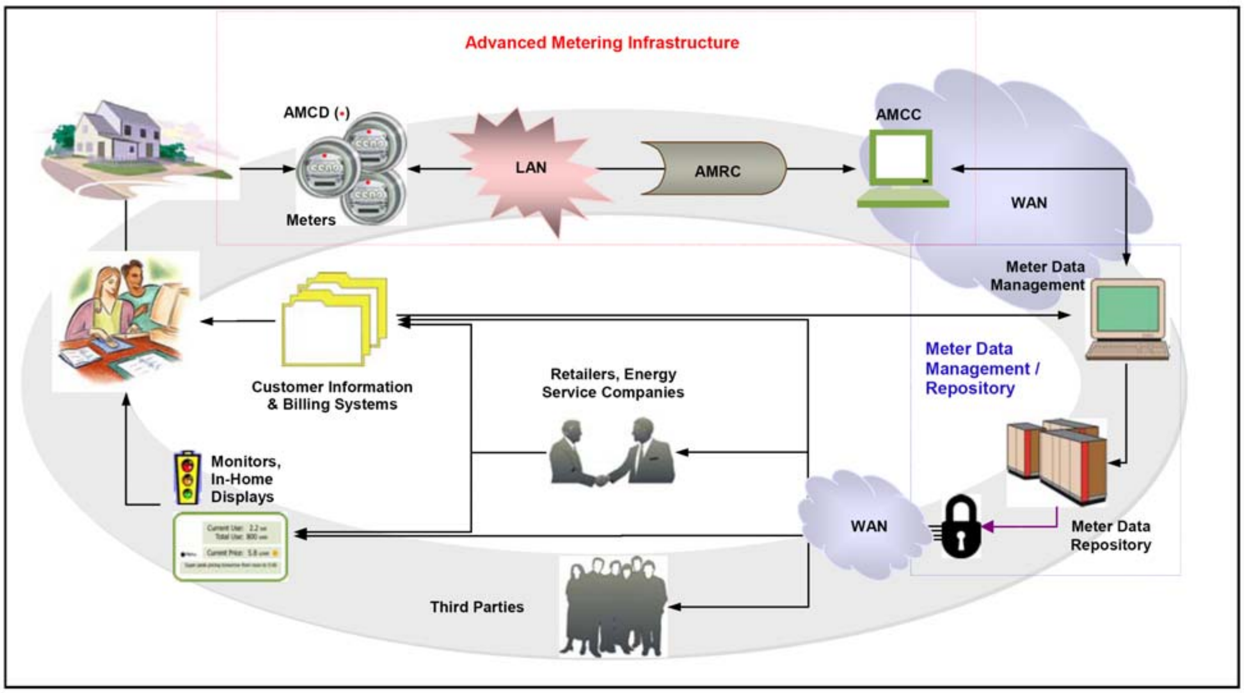
DAY OF ______________________________ 2008.
(Month)

Section 3: Project Overview

3.1 Smart Metering Infrastructure – AMI Landscape

The Advanced Metering Infrastructure (AMI) which CHEC is installing is meant to satisfy the requirements of the provincial Smart Meter Initiative (SMI), which is hoped to contribute to the creation of a conservation culture in Ontario. The metering and associated infrastructure (i.e. AMCDs, AMRCs, and AMCC) will be owned and operated by CHEC, and the centralized Meter Data Management/Repository (MDM/R) will be owned and operated by the Independent Electricity System Operator (IESO). There are performance requirements detailing success rates for data collection from the AMI infrastructure, and time requirements within which the data must be provided to the centralized MDM/R. Following is a diagram depicting the data flow for the Ontario Smart Meter landscape.

Figure 2: Ontario Smart Metering System Data Flow



Performance requirements for the AMI have been specified within the Ministry of Energy document entitled *Functional Specification for an Advanced Metering Infrastructure Version 2* (dated July 5, 2007), which has been provided for reference as Appendix "A". As discussed within this document the AMI system includes the Advanced Metering Communication Devices (AMCD), the Local Area Network (LAN), Advanced Metering Regional Collector (AMRC), the AMI Wide Area Network (AMI WAN) and an Advanced Metering Control Computer (AMCC). The system will provide the infrastructure within which date and time stamped hourly meter reads are remotely collected and transmitted daily to CHEC's AMCC, and which will eventually be sent to the centralized Meter Data Repository (MDM/R) through the MDM/R Wide Area Network (MDM/R WAN).

The MDM/R functions include collecting and storing data, processing it for TOU and CPP billing, and making it accessible to consumers and to LDC's in accordance with their billing cycles. The data will also be made available to retailers, energy service companies and other interested parties in a manner that protects the privacy of consumers.

As discussed in Section 1.3 *CHEC's Approach to Smart Metering*, CHEC members are currently engaged in a project to install Smart Metering in all residential and commercial locations by December 2010. Presently CHEC has a total of over 110,000 residential and commercial customers, with smart meter installation commencing 2009.

Planning for the Commercial and Industrial component of the smart meter initiative is currently being developed and is not part of the current deployment. However, Bidders are welcome to provide comments on their ODS offering for Commercial/Industrial data, and budgetary pricing may be provided separately should the Bidder decide to do so. Desirable Commercial and Industrial analytical tools have been described in Section 5.4 *Commercial and Industrial Data,* and the Bidder's information regarding these functionality components can be provided as per the Section format instructions included in Section 2.4 *Proposal Format Instructions*, however Bidders are to understand that the immediate requirements of CHEC are for a residential ODS solution to audit the performance of the AMI. The intent of the ODS is NOT to replicate any functions currently in place within the centralized MDM/R. CHEC looks to the ODS to facilitate the implementation of operational efficiencies (currently the centralized MDM/R does not accept operational metering data).

3.2 CHEC's Operational Data Storage Requirements

Section 3.1 *Smart Metering Infrastructure – AMI Landscape* outlines the requirements placed on CHEC in order to meet the provincial mandate.

The Operational Data Storage requirements being procured through this RFP document are considered (at this time) to be exclusive of the requirements being placed upon the IESO centralized MDM/R. The solution that is of interest to CHEC through this process will be utilized to audit the performance of the AMI infrastructure currently being installed, and to store operational data that may be of future use to CHEC. It is CHEC's understanding that these functionality components are standard to ODS solutions, and may not form part of the MDM/R functionality. CHEC would like to clearly express that their intention is NOT to duplicate infrastructure being implemented by provincial entities, but rather to ensure that the AMI infrastructure being deployed by CHEC will satisfy the needs of the Ontario Energy Board (i.e. the Regulator).

3.3 CHEC's Smart Metering Initiative: Current Environment

3.3.1 Description of Environment

For reference, we have also included the following information pertaining the CHEC's back office systems.

UTILITY	CIS:	Meters	Projected AMI Install:
Centre Wellington Hydro Ltd.	Harris Northstar	4,500	August 10, 2009
COLLUS Power Corp.	Harris Northstar	11,500	June 22, 2009
Innisfil Hydro	Harris	12,000	March 16, 2009
Lakefront Utilities Inc.	Harris	7,000	February 2, 2009
Lakeland Power Distribution Ltd.	Harris Northstar	7,000	April 6, 2009
Midland Power Utility Corporation	Harris v5.2.19	5,000	June 15, 2009
Orangeville / Grand Valley	Advanced	8,000	September 21, 2009
Orillia Power Distribution Corporation	Harris v5.2.19	9,000	March 2, 2009
Parry Sound Power Corporation	Harris v5.2.19	2,500	March 2, 2009
Rideau St. Lawrence Distribution Ltd.	Harris	4,500	April 27, 2009
Wasaga Distribution Inc.	Advanced	9,500	October 5, 2009
Wellington North Power Inc.	Harris Northstar	2,500	June 29, 2009
Westario Power Inc.	SAP	14,500	February 2, 2009

3.3.2 AMI Service Level Agreement

The AMI network has been deployed in such a manner as to accommodate the following performance levels:

i. Percent of hourly (interval) readings captured: 98% in 24 hours
ii. Percent of daily (register) readings captured: 98% in 24 hours
iii. In addition to the above requirements, 99% of all readings (99% of register, and 99% of interval) are required in 72 hours (rolling statistic), and 99.5% of all readings (99.5% of register, and 99.5% of interval) are required in 30 days (calendar statistic). These requirements will demonstrate the Bidder's ability to acquire the readings that were missed in 24 hours, over the subsequent time periods (i.e. continued commitment to acquire as many readings as possible).
iv. Percent of meters communicated within 24 hours: 99.9% (while it is conceded that some meters may be difficult to communicate with, and therefore acquire 100% of the readings 100% of the time, the aim of this statistic is to show that 99.9% of meters can be reached on a daily basis).

This information has been provided as one of the critical functions of the ODS will be to audit the performance of the AMI to ensure that these Service Levels are being satisfied.

3.4 Scope of Work

CHEC, through this RFP, is seeking a cooperative and mutually beneficial relationship with a ODS provider which will allow CHEC to successfully fulfill their regulatory requirements for data collection. That is, it is anticipated that the ODS services being procured will enable CHEC to ensure the performance requirements as documented in Section 3.3.2 *AMI Service Level Agreement* are being satisfied. Knowledge of AMI performance statistics will provide CHEC with the knowledge that sufficient AMI infrastructure has been deployed (or not), such that the performance expectations can be met.

Additionally, AMI systems provide data which can enable CHEC to implement operational enhancements for their customer base. Given that the AMI deployment is in its infancy, CHEC is not in a position to make use of all of the data that is acquired through the system at this time. However, it is CHEC's goal to establish the ODS system such that this information can be stored now, and utilized at a later time.

It is CHEC's intention to implement commercial and industrial applications as appropriate in the future. Planning for this application is ongoing, and no timelines for implementation are available at this time. Therefore, this request for proposal for ODS solutions will address CHEC's requirements for smart metering in residential applications only. However, Bidders should be aware that commercial and industrial applications will be installed in the future, and if the Bidder also provides a solution for commercial and industrial applications, the response may also address this solution distinctly segregated from the solution provided for residential application, if possible. If the proposed solution is applicable for commercial and industrial customers with no modifications, the Bidder shall identify such.

As stated within Section 1.3 *CHEC's Approach to Smart Metering*, it is the intent to procure the ODS solution in an ASP model to mitigate the risk associated with purchasing a license for software which may become redundant due to the ongoing development of the centralized MDM/R. CHEC supports the work of the IESO, and the use of the centralized system, and look to use the ODS to facilitate the introduction of Operational Efficiencies during the period in which these functions are unavailable through the centralized system.

CHEC considers the following list of services as required to successfully satisfy the intent of this RFP:

- Project management, system design, commissioning and training
- System security (i.e. detailed security parameters to protect all information collected)
- Service levels and value added services
- Applicable costs, pricing and rates
- Provide the technical expertise required to establish communications between the AMCC and CHEC's back office systems
- Establish an understanding of the demarcation point
- Describe the technology roadmap for the proposed system/technology

Section 4: Bidder Company Information

4.1 Financial / Business Stability

1) What is the current size (number of employees), turnover rates for last three (3) years, and location(s) of the Bidder's company?
2) Number of employees assigned to application development and support.
3) What is the current financial condition of the Bidder's company? Provide supporting documentation and annual reports for the last three years. If the company is privately held, supply sufficient information to document the company's financial status.

4.2 Experience providing same or similar products & services

1) How many years has the Bidder been in business?
2) How long has the Bidder been providing ODS solutions?
3) How long has the proposed solution been deployed and implemented in the field excluding any period of time for which it was in a Beta Test status?
4) Describe the Bidder's primary line of business and the percentage of its business derived from the sale of ODS solutions and associated services.
5) Bidders should identify and describe services they could offer CHEC as part of the Contract that would support environmentally responsible business practices.
6) Bidders are to provide data to support their safety record such as corporate safety statistics, internal safety record, WSIB rating, injury rate or injury severity. In addition, Bidders must provide documentation supporting their commitment to safety within their facilities and design of products.

4.3 Contract Manager

The Bidder is asked to acknowledge the requirement to designate a Contract Manager, who shall have the authority to handle and resolve any technical issues, disputes or contractual issues in a timely manner. The Bidder should describe the Contract Manager's experience with managing projects of a similar size and scope, including timelines, and results if applicable. Response should include the Contract Manager's and any other related team member's Curriculum Vitae (CV).

4.4 Perspectives expressed by references

To ensure long-term viability and maintenance of the system, the selected Bidder must be a proven vendor in the area of application software and therefore the following information is requested:

1) Provide a list of at least three (3) references (contact names and phone numbers) for companies using the Bidder's proposed system to perform the same or similar application(s) as the one(s) described in this RFP for the past three (3) years.

Section 5: ODS Solution Technical Requirements

5.1 General Data Management Requirements (I)

CHEC is seeking an AMI specific ODS that is designed to store meter data and provide isolation of business processes and business systems from the details of metering and meter data collection, in a multi-vendor, multi-technology environment.

Any ODS proposed by the Bidder shall allow for the application of consistent processes and the maintenance of consistent interfaces independent of how, when, or where various meter reading technologies are deployed. This is intended to simplify and significantly reduce the likelihood of errors in business processes that utilize meter data. It should also allow for the most cost-effective AMI meter reading technologies to be deployed, without affecting downstream processes.

Bidder is to propose a fully capable ODS system able to manage the ongoing collection of all cumulative and interval meters for electricity, and potentially water and gas, as required by CHEC's current structure and operational responsibilities.

The ODS shall utilize a relational and fully versioned database that provides for long-term data storage of register, interval, tamper, outage, and meter event data. The system will provide for business process integration, and be accessible by all business and analytical systems, and readable by users of meter data throughout the utility. The ODS should have the ability to collect energy data streams from physical metered channels, endpoints, or modules, or calculate it as needed. The data should be linked together in flexible relationships that are managed over time.

The ODS data model should provide isolation of users from the day-to-day details of meter reading data collection processing. However, the ODS shall still provide access to those details for the systems and users that require it.

5.2 System Integration (I)

Systems of interest with regards to system integration include CIS systems, Outage Management Systems (OMS), and AMI and other meter reading data collection systems. Bidders are asked to provide a listing of these systems which can currently integrate with the proposed solution. While these systems are of immediate interest, it is expected that CHEC members will investigate the integration of GIS, WFM systems, WEB presentment OMS and other utility data systems in the future. Bidders are invited to provide any information they deem relevant to these interests.

5.2.1 Interaction with AMI (CI)

The ODS solution shall provide the following functionality with regards to the handling of data as provided by the AMI infrastructure:

i. AMI data insertion into the ODS will be dynamic.
ii. The system will store data in the original time increments as provided by the AMI system (ie. RAW AMI data including missing intervals and bad data).
iii. The system will store validated register and interval data in any time increment (ie. Intervals of 1 minute, 2 minute, 5 minute, 15 minute, etc.).
iv. Data storage will be energy independent and the ODS will be capable of storing and processing readings from all registers of all AMI endpoints (endpoints can include electric, water, and gas meters, with all available data from each meter).

v. Hourly reads in the system must retain the precision of the meter, to a minimum precision of 10 Watt hours (.01 kWh) for each residential electric data register (interval or otherwise). Bidder is requested to also provide detail regarding the precision of data storage for Commercial/Industrial metering (i.e. It is expected that the ODS would retain the precision of the meter regardless of the number of decimal points.)

vi. The system will accommodate "Request and Response" brokering to/from multiple AMI systems.

Bidders are required, as per Section 2.8 *Grounds for Disqualification* to provide written acknowledgement of the requirement for the proposed solution to be currently capable of these functions for the Sensus AMI system.

5.2.2 Other Meter Reading Data Collection Systems (I)

In addition to the acquisition of Data from the AMI, the ODS shall handle meter data from multiple sources, such as handheld, mobile, fixed network, etc. The ODS will allow the integration of multiple advanced meter reading technologies from multiple suppliers. CHEC will require the ability to seamlessly deploy multiple technologies in conjunction with traditional meter reading methods, and the ability to merge modern and traditional meter reading methods and technologies without impacting or modifying downstream billing processes. This ability is considered of value given that CHEC continues to manually collect meter read data while they deploy their AMI network.

The ODS solution shall have the functionality to emulate and manage schedules, cycles, and routes of manual meter reading operations to allow transition of legacy meter reading tasks, including the functionality to:

i. Process cycle/route-based meter reading systems, such as handheld (i.e. Itron MV-RS) or automated meter reading technology (i.e. Itron ERT enabled electromechanical meters),

ii. Process non-cycle/route-based meter reading systems, such as two-way remote reading technologies (i.e. MV-90 interval data collection from POTS enabled communication modules),

iii. Manage schedules such that the ODS will request all of the meter reading required for a given billing (readings may actually be obtained from multiple systems and/or technologies),

iv. Maintain information about which system is used to obtain readings for each meter so that a given request can be broken into individual requests for each meter reading system,

v. Functionality to create partial or full routes when returning readings to the billing system and combine multiple commodities, i.e. water and gas, into a single meter reading route for field collection and return data to the ODS system.

vi. The ODS should maintain performance statistics for each meter reading system and for the system as a whole.

Given that the ODS can perform the functions listed above, in an effort to retain consistency in the presentation of data, CHEC requires that: time references in data presented must be based on the local time zone and use Daylight Savings Time. Any data that is presented that is not validated should be clearly indicated as such. For further validation requirements, see Section 5.3 *Validation, Editing and Estimation (VEE)*.

5.2.3 Customer Information System (CI)

The system should accommodate "Request and Response" Brokering To/From Multiple Customer Information Systems (CIS). Some of the CIS systems commonly utilized in the Ontario market include:

- Advanced
- Cayenta

- Daffron
- Harris NorthStar
- Harris 5.2.19.x
- HTE
- Peoplesoft
- SAP
- SPL

Bidders are requested to specify the CIS systems for which an interface currently exists, and whether there is a cost to implementing the interface that will be required for CHEC member's CIS systems. In the event that the ODS cannot interface with the CIS systems being used by CHEC (reference Section 3.3.1 *Description of Environment*), the Bidder is asked to provide a high level overview of their system's ease of customization.

As part of the synchronization that is required between ODS and CIS, it is expected that the proposed solution will allow for new or changed customer, account, site ID, and service point information, and that this information will be imported from the external Customer Information System (CIS) en masse or upon completion of service orders.

CHEC anticipates using the ODS to test the IESO Billing Request file format that will be utilized by the centralized MDM/R. If Bidders have experience in this regard, documentation should be included in the response.

5.2.3.1 Wholesale Settlement Calculations (I)

CHEC is interested in whether the system is capable of performing Wholesale Settlement Calculations with billing output files for CIS. If this option is not currently available, please detail the development path.

5.2.3.2 Export Capabilities (I)

In addition to the interface required to directly integrate CIS data, CHEC is interested in the proposed solution's ability to export data in XML format, and the Itron MVRS handheld format. Bidders are requested to provide information explaining their current functionality in this regard, as well as any associated costs to accommodate these requirements if they are not currently available. If incremental costs are not stated, it is CHEC's assumption that costs for this functionality is included in the system pricing (i.e. functionality is considered standard).

5.2.4 Outage Management System (CI)

It is expected that the proposed solution will allow for receipt and display of outage related events from the AMI. CHEC is interested in having these capabilities performed by the ODS system, thereby allowing improved restoration and other outage related services. With the information available from AMI it is expected that the dispatching process for field service crews will be streamlined.

Bidders are requested to provide a listing of interfaces available to integrate the proposed ODS with CHEC's OMS (reference Section 3.3.1 *Description of Environment*). If an interface is not currently available, Bidders should specify the estimated costs associated with the creation of the required interface. In addition to a list of interfaces, Bidders are asked to provide some details regarding past implementations and a list of references with regards to the integration of OMS.

5.2.5 Work Force Management (WFM) (I)

CHEC expects that initially all data will be imported from CIS. However, as the deployment of AMI continues, CHEC will require that the system allow new or changed data to be imported from the workforce management system at the completion of meter-related service orders. The system will allow configuration data to be synchronized on a daily basis using batch files, and should allow real-time transactions to be performed with web-based APIs. The ODS system should also have the ability to interface to the WFM system and automatically create service orders in events where a field visit is required.

5.2.6 3rd Party Interfaces (I)

The ODS must provide a robust, industry standard means for extracting data so that the data can be presented to other 3rd party applications. In addition to CIS, OMS, WFM, other 3rd party applications might include GIS, WEB products, Theft Analysis tools, Load Forecasting/Profiling tools, etc. Bidders are requested to provide detailed information regarding their experience integrating to 3rd party applications.

The system should contain Application Program Interfaces (APIs) for third party applications. The system should not have a load limitation to API's (multi-threaded). If there is a load limitation to API's, please indicate what the limitation is.

The ODS solution should contain the flexibility and functionality to load, change, correct, and view configuration data through use of the following tools:

i. Service Oriented Architecture (SOA) Bus;
ii. XML configurable import APIs (batch or real time);
iii. XML configurable export APIs (batch or real time);
iv. comma delimited file (CSV) exports (batch)
v. configuration attributes reports.

5.3 Validation, Editing and Estimation (VEE) (CI)

All meter data received by the ODS will be subjected to VEE processes. At this time, CHEC requires an ODS solution to process residential AMI data, and the VEE rules for this class of customer have been published by the IESO (*Meter Data Management and Repository (MDM/R) VEE Standard for the Ontario Smart Metering System Issue 1.0*; Attached as Appendix "B").

Bidders are expected to follow this validation process, and as part of this RFP are expected to provide a statement of compliancy that this process will be the standard implemented.

NOTE: As stated in Section 1.2 *Provincial Context for Project* it is NOT CHEC's intention to duplicate infrastructure. CHEC fully supports the intended integration with the centralized MDM/R; VEE according to the IESO rules is required so that validated data is available for CHEC's operational data requirements (i.e. load studies, etc.).

5.3.1 Data Aggregation and Analysis (CI)

The ODS will contain utility analytical tools to enable the aggregation of interval data units into billing determinant format/buckets as required by the CHEC CIS. This will include TOU buckets as provided by the OEB Regulated Price Plan (RPP), Critical Peak Pricing (CPP), and aggregated monthly consumption files for Market Participants.

In addition to data aggregation the ODS calculation engine shall also support advanced calculation capabilities including (but not limited to) the netting of bi-directional meters (enabling net-billing of bi-directional meters), auditable change tracking, the calculation of the maximum demand for any requested customers; when data is requested the proposed ODS solution will calculate (rather than utilize stored values) and calculations will be fully versioned. In addition, the ODS will fully version all formula definitions for calculated channels and registers, and track changes over time as well as corrections. If formulas change over time, the ODS will use the appropriate formula in calculations for each time period.

5.3.2 Ancillary Meter Functions

The ODS application will include the facility to trigger on-demand reads and provide the capacity for revenue protection (theft prevention). To aid in analytical capabilities, we want to ensure that the ODS has the ability to perform comparison scenarios with meter data (i.e. analyze the metering load at a transformer by creating a virtual meter with the load at the homes to perform a comparison and determine losses that exceed a certain prescribed level). The Bidder is to describe how their solution will provide these services.

5.4 Commercial and Industrial Data (I)

As per Section 3.1 *Smart Metering Infrastructure – AMI Landscape* and Section 3.4 *Scope of Work*, CHEC requires a residential ODS solution, however it is a future expectation that Commercial and Industrial data will be aggregated and analyzed within the proposed system.

Bidders are requested to provide details regarding any functionality specific to Commercial and Industrial Metering that have not been explained through responses to other sections within Section 5: *ODS Solution Technical Requirements* of this document.

5.5 ODS System Reporting (I)

To accommodate the provincial requirements for data management CHEC requires that reads missing from the previous 24-hour reporting period ending at midnight must be logged and reported through the system by 6:00 am the following morning. CHEC requires that the ODS make the following reports available according to the same timeline:

- Error,
- Process,
- Event,
- Administration,
- Interactive Graphic and Load Data,
- Statistical,
- Register,
- Manually Edited data, and
- Custom reports utilizing report writers (Crystal, COGNOS, etc).

Bidders are asked to provide description and examples of the above listed reports, and identify whether the information is provided through manually dispatched reports, or automatically dispatched reports.

It is CHEC's preference that the ODS, where possible, accommodate reporting requirements through Exception Reporting. Certain DASHBOARD functions have been identified herein which CHEC has determined would be of particular value in assisting staff with the management of the ODS functions, with the ongoing operational maintenance of AMI, and with the schedule maintenance associated with billing functions.

5.5.1 DASHBOARD: AMI SLA (AMI Performance Levels) (CI)

The ODS, by way of data validation, should be capable of determining the performance levels of the AMI network. We have included the required AMI performance levels in Section 3.3.2 *AMI Service Level Agreement* for reference. As per Section 2.8 *Grounds for Disqualification*, Bidders are required to complete compliancy statements regarding their capacity to perform the necessary audit functions.

It is CHEC's preference that the results of said audits can be displayed graphically, within one screen, or a portion of an Operations screen, demonstrating (at a glance) that the AMI is performing to the required levels and that the ODS functionality allow for the ability to generate emails on exception to advise users when the SLA has not been met. In the event that the AMI is encountering problems, the user should be able to click on the interactive DASHBOARD function and be provided with additional information to explain the problems being encountered (i.e. list of meters not reporting, etc).

If the Bidder does not have a DASHBOARD function to provide this information this should be clearly stated. In this case the Bidder should provide information regarding the level of exception reporting that is inherent to the system, and which might be utilized to determine the level of performance of the installed AMI.

5.5.2 DASHBOARD: Operational Data/Indicators/Events (CI)

It is CHEC's preference that the events produced by the AMI system (outage notification, restoration notification, tamper information, hi/lo voltage indicators, etc) can be displayed graphically, within one screen, or a portion of an Operations screen. In the event that the AMI is encountering problems, the user should be able to click on the interactive DASHBOARD function and be provided with additional information to explain the problems being encountered (i.e. list of meters experiencing power outage, events received to indicate tamper, etc)

If the Bidder does not have a DASHBOARD function to provide this information this should be clearly stated. In this case the Bidder should provide information regarding the level of exception reporting that is inherent to the system, and which might be utilized to efficiently capture events being produced by the AMI.

5.5.3 DASHBOARD: Billing Schedule Maintenance (CI)

It is CHEC's preference that ODS will be able to graphically display, within one screen, or a portion of a billing screen, the current status of the billing schedule. Required information would include cycles billed, cycles pending billing, cycles which have completed validation within the ODS, and cycles being read, as well as the scheduled dates associated with these processes.

If the Bidder does not have a DASHBOARD function to provide this information this should be clearly stated. In this case the Bidder should provide information regarding the level of exception reporting that in inherent to the system, and which might be utilized to efficiently capture events being produced by the AMI.

5.5.4 Reporting: Multiple Systems (I)

It is expected that the operational and performance reporting requirements described through Section 5.5 *ODS System Reporting* will be possible across all meter reading technologies that have been integrated within the ODS, and the ODS will track which meters are to be read by each meter reading technology and the progress of these systems as they deliver data. The ODS will be able to report on the quantity, quality, and timeliness of collected data.

5.5.5 Reporting: Graphing (I)

It is expected that the ODS will provide the ability to produce data graphs and reports for all metered and calculated channels. The system will be flexible, including such functionality as the ability to perform calculations at the time of producing graphs and reports (i.e. the graph or report will calculate and display the result). All graphs and reports shall be viewed within the ODS application user interface, as well as contain the functionality to enable data export to spreadsheets, or be transportable to other electronic file format, and saved as images for use in external reports, etc. Reports will be required to be run in either online or batch mode.

5.5.6 Reporting: Custom Queries (C)

The ODS will be capable of executing custom queries to accommodate any areas where standard reports are not available. The successful Bidder will be required to provide full database documentation (i.e. Data Model Diagrams, Table Relationships, Field Definitions).

As part of their submission, the Bidder should provide a description of how the service is managed in terms of assisting the End-User to understand the data base structures and relationships, the creation/promotion of optimal data queries, and the prevention of machine degradation due to the use of unoptimized queries.

5.5.7 ODS Access

CHEC requires that the system be configured in a "Thin Client" so that utility users can access and view data, and as a means to download data in spreadsheet format for ad hoc analysis. Bidder should provide detailed information pertaining to the flexibility and functionality of the proposed solution in this regard, and clearly define the software components residing on the server side and any software components residing on the client side.

5.6 Meter Event Manager (I)

The Bidder should describe their solution’s event management capabilities with regards to receiving, storing, filtering, normalizing, and transferring event data received from any/all meter reading systems. Event data can include power loss, power restore, tamper, tilt, low battery alarms, sags/swells, etc. Event messages from different meters and/or reading systems will be standardized by the ODS solution so that a downstream outage management system can receive the same message for “power off” or “power on” regardless of which meter reading data collection system returned said event. All events received will be stored in the ODS database.

The ODS shall also provide power outage event filtering, such that the downstream outage management system receives only relevant event types, such as power off and power on that are more current than some predefined time period. Event reporting for a given meter shall also be filtered temporarily by the ODS during meter installation and/or scheduled maintenance such that false outages are not transferred to outage management.

5.7 ODS System Disaster Recovery Planning (CI)

The ODS system must reside in Canada, have adequate system redundancy, and the ODS service provider will have recovery planning such that hardware failure at any level of the ODS system will not result in any system downtime lasting more than 2 hours, with no loss in data.

More severe disasters, resulting from more than simple hardware failure (eg. building fire or telecommunications interruption), will be recovered from within 24 hours, with no loss in data. The recovery plan may include having access to a backup ODS server located at a geographically separated site (at least 50 km) and means to publish data on the back-up server. The ODS system provider's disaster recovery plan will include a worst-case provision to ensure that no data is lost.

The Bidder's response should include details regarding the disaster recovery planning that will accommodate both levels of disaster recovery (i.e. 2 hour and 24 hour recovery).

5.8 ODS Performance Service Levels (CI)

AMI Vendors deploying systems in CHEC's service area are expected to perform to the following service levels:

- Percent of hourly (interval) readings captured: 98% in 24 hours
- Percent of daily (register) readings captured: 98% in 24 hours
- In addition to the above requirements, 99% of all readings (99% of register, and 99% of interval) are required in 72 hours (rolling statistic), and 99.5% of all readings (99.5% of register, and 99.5% of interval) are required in 30 days (calendar statistic). These requirements will demonstrate the Vendor's ability to acquire the readings that were missed in 24 hours, over the subsequent time periods (i.e. continued commitment to acquire as many readings as possible).
- Percent of meters communicated within 24 hours: 99.9% (while it is conceded that some meters may be difficult to communicate with, and therefore acquire 100% of the readings 100% of the time, the aim of this statistic is to show that 99.9% of meters can be reached on a daily basis).

It is CHEC's expectation that the ODS system will be able to definitively determine whether the AMI network is satisfying these requirements. The ODS system provider should provide sufficient details to explain how their solution will be able to corroborate the AMI's performance to these service level expectations.

In addition to substantiating the AMI service levels, it is expected that the ODS will provide:

- 99.7% uptime (i.e. 2 hours per month downtime)
- Validated data files within 12 hours (interval data)
- Meter events files within 24 hours
- Alarm notification files immediately (given that the AMI can provide this data, the ODS is expected to filter/scrub alarms against known service orders from CIS)

5.9 Scalability (CI)

The Bidder must describe its proposed ODS data model demonstrating the model's flexibility and scalability to deliver cumulative and interval metering over the next ten years. The system should be designed for a minimum of 250,000 customers, assuming 2 years of online interval data and 7 years off-line data storage. Please specify the methodology for data storage and retrieval.

5.9.1 Ongoing Resource Requirements

Bidders should indicate to CHEC the expected level of resources that is expected to be required for ongoing operation of the proposed ODS solution. CHEC expects that the ODS solution will be managing their entire electric meter population by end 2010. Assuming a meter population growth resulting for the implementation of gas and/or water AMI, the Bidder should explain how the required resources would be expected to change (or not), beyond 2010.

5.10 ODS System Security (CI)

It is essential that the ODS system have, as a minimum, end-to-end protection against cyber attack and unauthorized intrusions. The Bidder should describe how its ODS ensures against loss or tampering of data. Security requirements are needed to manage the level of access users have, and the Bidder's ODS solution should meet the following minimum standards:

i. The system will contain System Administration and Security Management functions
ii. The system shall support tiered user access levels, to ensure separation of access according to the user's roles and responsibilities.
iii. The system will allow access (with appropriate permissions) to Raw AMI data, VEE formatted data, and Manually Edited data.
iv. Read-only access shall be provided for accessing data by customer, by Site-ID account, or by meter for users for whom those are the reference points, including the ability to reference and search by historical IDs or names and effective dates after changes have been made.
v. All corrections of errors with these entities should also be maintained within the ODS. Functionality should exist to allow comparisons between versions, and also allow previous versions to be restored. For all changes and correction made, information about who (or what system) made the change, when the change was made, and why the change was made shall be maintained and made available through the use of audit logs.
vi. The ODS should be able to integrate to an LDAP directory service for user authentication. This provides the user credentials required for controlling access to the LDC system resources (eg. networks and servers for both external and internal users).

Section 6: Price Submission Requirements

Please note that all documentation must reflect current capabilities. Any future capabilities must be stated as such, and a development schedule outlined.

Describe in detail the pricing for the systems proposed. Detail any assumptions made in the proposed solution and pricing. All of this information should be included within the Pricing and Functionality Spreadsheet. **As per Section 2.4 *Proposal Format Instructions*, any hard copies of the pricing submission should be submitted in a separate envelope, marked "PRICE OFFER".**

In addition to the minimum functionality required by the Ministry of Energy, CHEC is interested in the ability to support load control devices, and multi-utility meters, as this capability is in line with both the intent of the Ministry of Energy, and the service goals of CHEC members. Therefore, in addition to the current data collection requirements outlined in Section 3.3.2 *AMI Service Level Agreement*, CHEC expects to increase non-scheduled data communications to the network. These anticipated communications would in all likelihood include only specific areas, and affect low volumes of meters during any one communication.

6.1 Pricing and Compliancy Submission

The Pricing Spreadsheet allows for the Bidder to provide two options for the proposed ODS Infrastructure:

1) Within the tab labelled "Pricing_Option1_ASP" Bidders are required to submit pricing (Capital and 15 year Operating costs) for the proposed ODS Solution, as per the requirements of this RFP document (i.e. ASP model, with capability to accept Sensus AMI network data, perform AMI audit, etc.).
2) Within the tab labelled "Pricing_Option2" Bidders have the option to provide pricing alternative to that provided through Option 1. **NOTE: Pricing Option 1 is required, Pricing Option 2 is optional.** Currently the tab is structured for a license bid price submission, however the Option 2 tab has been provided in the event that Bidders feel that Pricing outside of an ASP model can better represent their model, and will allow Bidders to be creative in demonstrating the value of their solution (i.e. Bidders are free to modify the tab to demonstrate such options as higher upfront capital to allow decreased O&M costs, etc.).

6.2 Incremental Costs

In addition to the Pricing Options described in Section 6.1 *Pricing and Compliancy Submission*, Bidder's are required to submit the incremental cost for any functionality that is discussed in their proposal which does not come standard with their product. If an incremental cost is not provided, it is CHEC's understanding that the functionality comes standard with the product being proposed.

Section 7: Contract Terms and Conditions

7.1 Commencement of Contract Time

The successful Vendor shall be notified by CHEC of acceptance of the Vendor's Submission by CHEC sending a Purchase Order. The Vendor shall acknowledge receipt within ten days of the date of sending of the Purchase Order.

The Contract Time shall commence to run on the effective date indicated in the Purchase Order. Vendor shall start to perform the work on the date when the Contract Time commences.

7.2 Vendor Claims

All claims of the Vendor and all questions relating to the interpretation of the Contract, including all questions as to the acceptable fulfillment of the Contract on the part of the Vendor and all questions as to compensation, shall be submitted in writing to the CHEC Project Manager for determination.

All such determinations and other instructions of CHEC will be final unless the Bidder shall file with CHEC a written protest, stating clearly, and in detail the basis thereof, within fifteen (15) calendar days after CHEC notifies the Bidder of any such determination or instruction. CHEC will issue a decision upon each such protest within fifteen (15) calendar days and its decision will be final. Work will not be undertaken until a written final decision is rendered.

7.3 Changes in the Work

CHEC, without invalidating the Contract, may direct the Vendor to perform extra work or make changes in the work, provided that all changes or additions form an inseparable part of the work contracted for. Vendor shall make such changes or additions only after receipt of written instructions to do so from CHEC. If such changes or additions cause an increase or decrease in the cost of the Contract, or in the time required to complete the Contract, the adjustment to the contract price or time frames shall be as set out in the Change Order and the Contract shall be modified accordingly.

When a change is ordered, a change order shall be executed by CHEC and the Vendor before any change order work is performed. Any increase or decrease in the contract price and the time required for the completion of the contract work due to a change order shall be specifically set out in the change order. All terms and conditions contained in the Contract documents shall be applicable to change order work. The amount of any increase or decrease shall be added to or subtracted from the contract price as appropriate.

7.4 Delays & Extension of Time

If the Vendor is delayed at any time in the progress of the work by any act or neglect of CHEC, or any cause beyond the Vendor's reasonable control, he shall file with CHEC a notification that an extension of the Contract period is required.

The CHEC Project Manager shall review said notice and to the extent that the Vendor can reasonably demonstrate to CHEC Project Manager that it shall be delayed in its fulfillment of these terms and conditions and other obligations of this transaction due to a cause beyond its control, a reasonable extension period shall be granted.

7.5 Termination of Right to Proceed

CHEC may, in writing, terminate this Contract in whole or in part at any time, either for CHEC's convenience or for the default of the Vendor. Upon such termination, all data, plans, specifications, reports, estimates, summaries, completed work and work in process, and such other information and materials as may have been accumulated by the Vendor in performing this Contract shall, in the manner and to the extent determined by CHEC, become the property of CHEC. If the termination is for the convenience of CHEC and without default by the Vendor, an equitable adjustment for the Vendor's direct costs and profit for work actually performed shall be made by mutual agreement between the Vendor and CHEC. No amount shall be allowed for anticipated profit on unperformed services. Any expense incurred because of cost of completion by CHEC is chargeable to and shall be paid by the Vendor. The total liability to the Vendor shall be limited to the Contract value less the value of any equipment, material or completed services retained by CHEC member utilities.

Default occurs if the Vendor (1) abandons the work called for hereunder, (2) files a voluntary petition in bankruptcy or fails to obtain dismissal of an involuntary petition in bankruptcy within sixty (60) days after the filing thereof or has a Receiver/Trustee appointed, (3) becomes insolvent, (4) assigns this Contract or sublets any part of the work hereunder without prior written permission of CHEC, (5) repudiates the Contract, (6) allows liens to be filed against property of CHEC, (7) fails to meet or perform its obligations hereunder after five days notice or continues in chronic default of its obligations, (8) disregards laws, ordinances, rules and regulations related to the Contract and the work or disregards instructions of CHEC, (9) fails to complete the work in accordance with the Contract.

7.6 Right to Operate Unsatisfactory Equipment

If the operation or use of the materials or equipment after delivery and/or installation does not comply with the technical requirements set out in the Contract Documents to CHEC, CHEC shall have the right to operate and use such materials or equipment until such deficiency can be reasonably corrected provided that the period of such operation or use pending correction shall not impede or delay the ability of the Vendor to perform corrections. Such operation and use shall not constitute an acceptance of any part of the work, nor shall it relieve Vendor of any requirements of the Contract, nor shall it act as a waiver by CHEC of any requirement of the Contract.

7.7 Casualty Insurance

Before commencing work under this contract the Vendor at his own expense shall submit Certificates of Insurance, providing evidence acceptable to CHEC indicating that the Vendor has obtained and will maintain insurance for the duration of the contract. The following requirements apply to all Certificates of Insurance:

1) The insurance shall be written by an insurer acceptable to CHEC,
2) The insurance shall be primary to any coverage carried by CHEC.
3) The Vendor further agrees to provide CHEC with an executed Certificate of Insurance before commencement of work, and with written copies of the insurance policies at any time upon the written request of CHEC.
4) The Certificate of Insurance shall be an original copy signed by an authorized representative of the insurance carrier(s). (Note – faxed copies may be accepted initially to be followed up by originals in a reasonable length of time.)
5) The Certificate of Insurance shall provide that no less than 30 days advance notice will be given in writing to CHEC prior to cancellation, termination or alteration of the insurance coverage. CHEC shall be named as an additional insured on each General Liability Insurance Policy and any Excess Liability Policy or Umbrella Policy used to meet the required general liability limits.

The types of coverage and minimum limits are as follows:

1) GENERAL LIABILITY*
   a) $4,000,000 each occurrence
   b) $6,000,000 general aggregate
2) AUTOMOBILE LIABILITY*
   a) Bodily injury $1,000,000 per person
   b) $1,000,000 per accident
   c) Property damage $500,000 or
   d) Combined Single Limit $1,000,000

** A blanket, umbrella, and/or excess liability policy(s) may be utilized to increase limits to the desired level(s).*

7.8 Subcontractors

CHEC reserves the right to refuse to permit any person or organization (subcontractor) to participate in the work covered by this Contract, such refusal shall not be unreasonably imposed. No subcontract shall relieve the Vendor of any liabilities or obligations under the Contract, and the Vendor agrees that Vendor is fully responsible to CHEC for the acts and omissions of Vendor's subcontractors and of persons employed by them. Vendor shall require every subcontractor to comply with the provisions of the Contract.

7.9 Payment

Payment shall be made based upon completion of the performance milestones itemized below.
Vendor shall submit to CHEC a request for payment for each milestone that has been met. Payment for each milestone shall also be contingent on successful completion of the preceding milestones.

1) Fifteen percent (15%) of the contract price will be paid after the successful Acceptance Test, which requires delivery and integration of the system head-end.
2) Twenty five percent (25%) of the contract price will be paid after delivery of 35% of the communication infrastructure and 35% of the new meters and other customer premises equipment.
3) Twenty percent (20%) of the contract price will be paid upon successful installation, operation and route Acceptance of the equipment described in (2) above and delivery of an additional 30% all equipment on CHEC's system.
4) Twenty percent (20%) of the contract price will be paid upon successful installation, operation and route Acceptance of the equipment described in (3) above and delivery of all remaining system elements.
5) Twenty percent (20%) upon completion of system installation, Acceptance of all routes, and delivery of all documentation, judged by CHEC to be acceptable, in any event not longer than 90 days after complete installation.

CHEC will make payment within thirty (30) days of receipt of a request for payment, if above conditions are met.

When the Vendor has completed all work in accordance with the terms of the Contract Documents, the Vendor shall submit to CHEC a request for final payment. The request for final payment shall constitute a waiver of all claims by the Vendor except for claims specifically listed in the request.

Vendor's submission of its request for final payment shall constitute its warrant that the Vendor has to the best of its knowledge fully completed all work included in the Contract and has fully paid for labour, materials, equipment, services, taxes and all other costs and expenses resulting from this Contract.

7.10 Acceptance

These terms and conditions becoming binding when the Vendor's Submission chosen for acceptance by CHEC is given written notice of acceptance of the submission.

No modification hereof and no condition stated by Vendor in accepting or acknowledging this order, which is in conflict or inconsistent with, or in addition to the terms and conditions set forth herein, shall be binding upon CHEC unless accepted in writing by CHEC.

7.11 Shipments

Vendor shall mail Bill of Lading and Shipping Memo to destination, and CHEC's Project Manager.

Vendor shall notify the CHEC Project Manager promptly if unable to make shipment. Shipments shall be made to multiple destinations in CHEC's service territory for logistical convenience. Such shipment instructions will be stated in the purchase contract that will be developed between the selected Vendor and CHEC.

7.12 Prices

Vendor agrees that prices are firm unless otherwise noted, and Vendor warrants that said prices do not exceed the prices allowed by any applicable Federal, Provincial or Local regulation.

7.13 Compliance with Laws

Vendor warrants that in performing work under this order Vendor will comply with all applicable laws, rules and regulations of governmental authorities and agrees to indemnify and save CHEC harmless from and against any and all liabilities, claims, costs, losses, expenses, and judgments arising from or based on any actual or asserted violation by the Vendor of any such applicable laws, rules and regulations.

7.14 Patents

Vendor agrees to protect and save harmless CHEC from all costs, expenses or damages, arising out of any infringement of claim or infringement or Patents in CHEC's use of material or equipment furnished pursuant to this order.

7.15 Assignment

Vendor agrees that neither this order nor any interest herein shall be assigned or transferred by Vendor except with the prior written approval of CHEC.

7.16 Substitution

No substitution will be permitted under this order except on specific written authority of CHEC's Project Manager.

Appendix A

Ministry of Energy (MoE)
Functionality Specification for an
Advanced Metering Infrastructure
Version 2 (Dated July 5, 2007)

FUNCTIONAL SPECIFICATION

FOR AN

ADVANCED METERING INFRASTRUCTURE

VERSION 2

July 5, 2007

FUNCTIONAL SPECIFICATION

FOR AN ADVANCED METERING INFRASTRUCTURE

Table of Contents

FUNCTIONAL SPECIFICATION

FOR AN ADVANCED METERING INFRASTRUCTURE

1.0 APPLICATION OF SPECIFICATION

This Specification sets the required minimum level of functionality for AMI in the Province of Ontario for residential and small general service consumers where the metering of demand is not required. This Specification is not intended to apply to net metering applications.

2.0 FUNCTIONAL SPECIFICATION

2.1 Deployment

This Specification shall be met regardless of the size or scope of the AMI deployment by a distributor.

2.2 Minimum Functionality

2.2.1 As a minimum:

2.2.1.1 AMI shall collect Meter Reads on an hourly basis from all AMCDs deployed by a distributor and transmit these same Meter Reads to the AMCC and MDM/R, as required, in accordance with these Specifications; and

2.2.1.2 A Meter Read shall be collected, dated and time stamped at the end of each hour (i.e. midnight as represented by 24:00).

2.2.2 The date and time stamping of Meter Reads shall be recorded as year, month, day, hour, minute (i.e. YYYY-MM-DD hh:mm).

2.2.3 All meters shall have a meter multiplier of one (1).

2.2.4 Distributors shall provide the MDM/R with the service multiplier for transformer-type meters.

2.3 Performance Requirements

2.3.1 Collection and Transmission of Meter Reads:

2.3.1.1 AMI shall successfully collect and transmit to the AMCC and MDM/R at least 98.0% of the Meter Reads from all AMCDs deployed by a distributor in any Daily Read Period.

2.3.1.2 Meter Reads unsuccessfully collected or transmitted shall not be due to the same AMI component (including, without limitation, any AMCD) during any three (3) month consecutive time period.

2.3.1.3 AMI shall be able to collect and transmit Meter Reads during its operating life without requiring a field visit.

2.3.2 Transmission Accuracy: Over the Daily Read Period, 99.9% of the Meter Reads received by the AMCC shall contain the same information as that collected by all AMCDs deployed by the distributor.

2.3.3 AMI shall be capable of providing Meter Reads with a precision of at least 10 Watt-hours (0.01 kWh).

2.4 Technical Requirements

2.4.1 When an AMI includes AMRCs, the AMRCs shall have the ability to store meter data to accommodate the performance requirements in section 2.3.1.

2.4.2 Time Synchronization:

2.4.2.1 AMI shall be operated and synchronized to Official Time, as set by the National Research Council of Canada.

2.4.2.2 AMI shall have the capability of adjusting for changes due to local daylight savings time.

2.4.2.3 AMI installed within a distributor’s service area shall have the capability of accommodating more than one (1) time zone.

2.4.2.4 Time synchronization shall be maintained in the AMI to the specified accuracy parameters set out in section 2.4.3.1 following a loss of power.

2.4.2.5 All Meter Reads shall adhere to accurate time synchronization processes to ensure an accurate accounting of electricity consumption at each meter.

2.4.3 Time Accuracy:

2.4.3.1 At all times, time accuracy in the AMI shall not exceed a ±1.5 minute variance from the time established in section 2.4.2.1.

2.4.3.2 AMI shall be able to prove that time accuracy does not exceed the permitted time variance identified in section 2.4.3.1.

2.4.4 Loss and Restoration of Power:

2.4.4.1 AMI shall detect and identify the interval in which a loss of power occurred during a Daily Read Period.

2.4.4.2 AMI shall detect and identify the interval in which power was restored following a loss of power.

2.4.5 Environmental Tolerances: All AMI components (except the AMCC) shall operate and meet the requirements in these Specifications within a temperature range of minus thirty degrees Celsius (–30° C) to positive sixty-five degrees Celsius (+65° C), and within a humidity range of zero percent (0%) to ninety-five percent (95%) non-condensing.

2.5 Advanced Metering Communication Device (AMCD)

2.5.1 Installation Within the Meter:

2.5.1.1 The AMCD shall not impair the ability of the meter to be visually read.

2.5.1.2 Meters in which an AMCD is installed shall be able to be installed in existing meter sockets or enclosures.

2.5.1.3 AMCD shall meet or exceed ANSI standards to withstand electrical surges and transients.

2.5.2 Labelling:

2.5.2.1 The AMCD shall be permanently labelled with:

(1) Legally required labelling;

(2) Manufacturer's name;

(3) Model number;

(4) AMCD identification number;

(5) Input/output connections;

(6) Date of manufacture; and

(7) Bar code for tracking and inventory management.

2.5.3 When installed at a consumer's location, the meter shall visibly display, as a minimum, the AMCD identification number, meter serial number and LDC badge number for the meter.

2.5.4 The AMCD shall be able to be initialized or programmed during, or prior to, field installation.

2.6 Transmission of Meter Reads

2.6.1 All Meter Reads collected during the Daily Read Period shall be received by the AMCC and transferred to the MDM/R no later than 5:00 a.m. local time following the Daily Read Period.

2.6.2 Meter Reads are not required to be transmitted in a single transmission and may be transmitted as frequently as necessary in order to meet the requirements in section 2.6.1.

2.6.3 AMCC shall transfer the information identified in section 2.6.1 using an approved protocol and file structure.

2.7 Advanced Metering Regional Collectors (AMRC)

2.7.1 LAN Communication Infrastructure:

2.7.1.1 The spectrum allocation and wattage of the radio signal used by an AMI shall not impede neighbouring frequencies.

2.7.2 When an AMI includes AMRCs:

2.7.2.1 The AMI shall provide for the continuous powering of AMRCs regardless of their location and placement.

2.7.2.2 All AMCDs shall be able to collect and transmit Meter Reads when one or more AMRC has a loss of power.

2.7.2.3 Memory and software parameters shall be maintained at all AMRC during a loss of power, whether by the provision of backup/alternate power or other solution.

2.8 Advanced Metering Control Computer (AMCC)

2.8.1 Each AMCC shall have the ability to store a rolling sixty (60) days of Meter Reads.

2.8.2 A distributor shall not aggregate Meter Reads into rate periods or calculate consumption data from the Meter Reads collected through its AMI either in its AMCC or any other component.

2.8.3 The AMCC shall be able to perform basic operational verification of Meter Reads received before transmitting these Meter Reads to the MDM/R.

2.9 Customer Account Information

2.9.1 Distributors shall provide initial information associated with customer accounts to the MDM/R on a date to be determined.

2.9.2 On an ongoing basis, distributors shall provide information associated with any change to the initial information identified in section 2.9.1 to the MDM/R at a frequency to be determined.

2.9.3 Information to be provided to the MDM//R pursuant to sections 2.9.1 and 2.9.2 is to be determined.

2.10 Monitoring & Reporting Capability

2.10.1 The AMI shall have non-critical reporting functionality and critical reporting functionality as required in this section 2.10. Information generated from this reporting functionality shall be available to the MDM/R.

2.10.2 Non-critical reporting:

2.10.2.1 At the completion of every Daily Read Period and following a transmission of Meter Reads, the AMCC shall generate a status report that includes information regarding anomalies and issues affecting the integrity of the AMI or any component of the AMI including information related to any foreseeable impact that such anomalies or issues might have on the AMI's ability to collect and transmit Meter Reads.

2.10.2.2 In addition to section 2.10.2.1, the AMCC shall generate reports:

(1) Confirming successful initialization of the AMCD's installed in the field;

(2) Confirming data linkages among an AMCD identification number, LDC badge number, serial number and customer account;

(3) Confirming that the MDM/R has successfully received notification of any changes to customer account information;

(4) Confirming that the AMCC has successfully made changes to customer account information following receipt of same from the MDM/R;

(5) Confirming the successful collection and transmission of Meter Reads or logging all unsuccessful attempts to collect and transmit Meter Reads, identifying the cause, and indicating the status of the unsuccessful attempt(s) pursuant to section 2.3.1;

(6) Confirming the accuracy of the Meter Reads received by the AMCC pursuant to section 2.3.2;

(7) Confirming that all Meter Reads have a precision of at least 10 Watt-hours (0.01 kWh) pursuant to section 2.3.3;

(8) Confirming whether the Meter Reads acquired within the Daily Read Period are in compliance with the time accuracy levels identified in section 2.4.3;

(9) Confirming whether time synchronization within the AMI or any components of the AMI has been reset within the Daily Read Period;

(10) Identifying the intervals in which a loss of power occurred and at which power was restored, following a loss of power;

(11) Addressing the functionality of the AMCD communication link, including status indicators related to the AMCD and AMRC;

(12) Identifying suspected instances of tampering, interference and theft;

(13) Flagging potential network, meter and AMCD issues; and

(14) Identifying any other instances that impact or could potentially impact the AMI's ability to collect and transmit Meter Reads to the AMCC and/or MDM/R on a daily basis.

2.10.2.3 Following a transmission of Meter Reads or at the completion of every Daily Read Period, the information in section 2.10.2.2 (5) shall be stored and used by the AMCC to assess compliance with the requirement specified in section 2.3.1.2.

2.10.2.4 The reports generated in sections 2.10.2.1 and 2.10.2.2 shall be made available to the MDM/R with a frequency to be determined.

2.10.3 Critical reporting:

Critical events are defined to include any AMI operational issue that could adversely impact the collection and transmission of Meter Reads during any Daily Read Period.

2.10.3.1 The AMI shall identify and report the following to the distributor:

(1) AMCD failures;

(2) AMRC failures;

(3) Issues related to the storage capacity of any component of the AMI;

(4) Communication links failures;

(5) Network failures; and

(6) Loss of power and restoration of power.

2.10.3.2 The reports generated in section 2.10.3.1 shall be made available to the MDM/R.

2.11 Security and Authentication:

2.11.1 The AMI shall have security features to prevent unauthorized access to the AMI and meter data and to ensure authentication to all AMI elements.

2.12 Proven Technology

2.12.1 The AMI shall be a technology that has been proven to reliably comply with these Specifications.

2.13 Regulatory Requirements

2.13.1 The AMI shall meet all applicable federal, provincial and municipal laws, codes, rules, directions, guidelines, regulations and statutes (including any requirements of any applicable regulatory authority, agency, board, or department including Industry Canada, the Canadian Standards Association, the Ontario Energy Board and the Electrical Safety

Authority) (collectively, "**Laws**"). For greater certainty, the AMI shall meet all applicable Laws that are necessary for the measurement of data and/or the transmission of data to and from the consumers within the Province of Ontario, including Laws applicable to metering, safety and telecommunications.

2.14 Water or Natural Gas Meter Reads

2.14.1 The AMI should be capable of supporting an increased number of Meter Reads associated with the reading and transmission of water and/or natural gas meters through additional ports on the AMCD, through optionally available multi-port AMCDs, or through additional AMCD/AMRC devices that are compatible with operating on the AMI. When procuring AMI, distributors shall obtain an indication of the capabilities of the proposed AMI to read water and natural gas meters, indicating the makes and models of such meters that can be read, and any requirements for retrofitting them.

3.0 DEFINITIONS

Within this Specification the following words and phrases have the following meanings:

"AMCC" is an advanced metering control computer that is used to retrieve or receive and temporarily store Meter Reads before or as they are being transmitted to the MDM/R. The information stored in the AMCC is available to log maintenance and transmission faults and issue reports on the overall health of the AMI to the distributor.

"AMCD" is an advanced metering communication device that is housed either under the meter's glass or outside the meter. It transmits Meter Reads from the meter directly or indirectly to the AMCC.

"AMI" means an advanced metering infrastructure. It includes the meter, AMCD, LAN, AMRC, AMCC, WAN and related hardware, software and connectivity required for a fully functioning system that complies with this Specification. With some technologies, an AMI does not include AMRCs. An AMI does not include the MDM/R.

"AMRC" is an advanced metering regional collector that collects Meter Reads over the LAN from the AMCD and transmits these Meter Reads to the AMCC.

"consumer" or "customer" means a person who uses, for the person's own consumption, electricity that the person did not generate.

"distributor" has the meaning provided in the *Ontario Energy Board Act, 1998*.

"Daily Read Period" means the 24-hour period for collecting Meter Reads, subject to the two periods annually during which changes to and from daylight savings time take place. The Daily Read Period ends at 12:00 midnight of each day.

"LAN" means a local area network, the communication network that transmits Meter Reads from the AMCD to the AMRC.

"meter multiplier" is the factor by which the register reading must be multiplied to obtain the registration in the stated units.

"Meter Read" is a number generated by a meter that reflects cumulative electricity consumption at a specific point in time.

"MDM/R" means the meter data management and meter data repository functions within which Meter Reads are processed to produce rate-ready data and are stored for future use.

"Specification" means these functional specifications.

"transformer-type meter" means a meter designed to be used with instrument transformers.

"WAN" means a wide area network, the communication network that transmits Meter Reads from the AMRC to the AMCC or, in some systems from the AMCD directly to the AMCC, and from the AMCC to the MDM/R.

Appendix B

Meter Data Management and Repository (MDM/R) VEE Standard for the Ontario Smart Metering System Issue 1.0

STANDARD

Power to Ontario.
On Demand.

Meter Data Management and Repository (MDM/R)

VEE Standard for the Ontario Smart Metering System

Issue 1.0

This document provides the Standards for Validation, Estimation, and Editing of Meter Read Data performed by the MDM/R for the Ontario Smart Metering System

Disclaimer

Status of this Standard

This document was placed under formal change control on March 20, 2008 with the posting of Issue 1.0. However, as of this date, portions of Sections 3, 4, 5, 6 and 7 pertaining to Commercial & Industrial metering are still under review and may be subject to revision. These sections have been highlighted in "yellow".

Document ID	IESO_STD_0078
Document Name	Meter Data Management and Repository (MDM/R) - VEE Standard for the Ontario Smart Metering System
Issue	Issue 1.0
Reason for Issue	VEE Standard issued under formal change control.
Effective Date	March 20, 2008

Document Change History

Issue	Reason for Issue	Date
0.1	Draft VEE Standard for discussion with SMSIP Working Group	January 3, 2007
0.2	Updated and presented to the SMSIP Working Group Sub-committee	January 8, 2007
0.3	Updated and presented to the SMSIP Working Group Sub-committee	January 12, 2007
0.4	Updated with SMSIP Working Group Sub-committee	January 14, 2007
0.5	Updated with Input from Sub-committee members	January 25, 2007
0.6	Updated with Information from the MDM/R Detail Design Document Version 1.9	March 15, 2007
0.7	Updated to incorporate changes per the review of the VEE Sub-Committee	March 19, 2007
0.8	Update of Table 7-5 Default VEE Services Configuration	March 22, 2007
0.9	General revision to reflect additional detail provided in Version 2.0 of the Detailed Design	March 7, 2008
1.0	Document placed under formal change incorporating input of the SMSIP Working Group VEE Sub-Committee	March 20, 2008

Related Documents

Document ID	Document Title	Issue
Ontario Regulation 440/07	*Functional Specification for an Advanced Metering Infrastructure – Version 2*	July 5, 2007
Ontario Energy Board	*Distribution System Code*	Last Revised on June 27, 2007
MDM/R Detailed Design	*Meter Data Management and Repository MDM/R V1.0 Detailed Design Version 2.0*	March xx, 2008
IESO_SPEC_9027	*MDM/R V1.0 Technical Interface Specifications Version 2.3*	30 November 2007
SME_SPEC_0001	*MDM/R V1.0 Reports Technical Specifications Version 2.6*	14 February 2008
Ontario Energy Board Smart Meter Implementation Plan	*Draft Report of the Board For Comment*	November 9, 2004
SOR/86-131	*Electricity and Gas Inspection Regulations*	January 28, 2008

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Table of Changes

The following is a summary of changes to this document from Issue 0.8 dated March 22, 2007.

Reference (Section and Page)	Description of Change
Title Page	• Revised document title
Related Documents	• Updated reference to AMI Function Specification • Updated reference to Distribution System Code • Updated reference to MDM/R Detailed Design Document • Added references to MDM/R Technical Interface Specifications and MDM/R Reports Technical Specifications • Added reference to the Electricity and Gas Inspection Regulations
Section 1, pages 1-3	• Updated role of the OEB as described in the Introduction • Added assumptions regarding net metering and metering for all classification of generators • Updated description of Section 2
Section 2, pages 7-14	• Expanded description of AMI Quality and Completeness tests and Data Quality flags • Relocated and updated new Section 2.3.1 from Section 3 • Relocated and updated new Section 2.3.2 from Section 4 • Added new Section 2.3.3 providing descriptions of Data Collection and VEE Reports
Section 3, pages 15-22	• General re-organization of this section for clarity (changes not tracked) • Update throughout to describe ‘message’ validation services • Update of descriptions of all validation checks to provide greater specificity • Added initial draft of validation services for C&I metering
Section 4, pages 23-29	• General re-organization of this section for clarity (changes not tracked) • Update throughout to describe ‘message’ estimation routines • Update of descriptions of all estimation routines to provide greater specificity • Added initial draft of estimation services for C&I metering
Section 5, page 33	• Added initial draft of editing support for C&I metering
Section 6, pages 35-37	• Update of descriptions of Billing Validation Sum Check to provide greater specificity • Added initial draft of estimation services for C&I metering

Section 7, pages 39-52	• General re-organization of this section for clarity (changes not tracked) • Update throughout to describe 'message' validation and estimation routines • Update of descriptions of all validation and estimation parameters to provide greater specificity • Update of descriptions of Billing Validation Sum Check parameters to provide greater specificity • Additions to VEE Services tabulation to reflect additional parameters • Added placeholder for C&I metering VEE Services
Section 7.2, Table 7-5, pages 50-51	Updates to validation parameters for default VEE Services based on review and input by the SMSIP Working Group VEE Sub-Committee • Confirmed application of the Maximum Demand Check to VEE Services 02, 03, 04, 05, 06, and 07 by setting 'Maximum Demand Check' check service parameter to "Y" • Confirmed application of the Consecutive Zeros Check to VEE Services 02, 03, 04, 05, 06, and 07 by setting 'Consecutive Zeros Check' check service parameter to "Y" Updates to estimation parameters for default VEE Services based on review and input by the SMSIP Working Group VEE Sub-Committee • Disabled Linear Interpolation for VEE Services 03, 04, 05, 06, and 07 setting 'Max Interpolation Minutes' to zero • Confirmed use of Register Read Scaling for VEE Services 03, 04, 05, 06, and 07 setting 'Register Read Allocation' parameter to "Y" • Confirmed use of Newest Like Day for VEE Services 03, 04, 05, 06, and 07 setting 'Newest Like Day Method' parameter to "Newest Like Day" and 'Newest Like Day Limit' parameter to "1" day • Confirmed use of Class Load Profile estimation only for VEE Service 07 – Seasonal establishing the following parameter settings: o 'Use Class Load Profiles' = "Y" o 'Class Profile ADU Min Days' = 5 days o 'Class Profile ADU Oldest Day' = 30 days o 'Class Profile ADU Newest Day' = 1 day Established initial Billing Validation Sum Check parameter settings based on review and input by the SMSIP Working Group VEE Sub-Committee • For VEE Services 01 and 02 o 'BillingSumCheck' = "N" • For VEE Services 03, 04, 05, 06, and 07: o 'BillingSumCheck' = "Y" o 'BillingSumCheckFail Action' = "Value" o 'MaxRegisterRange' = "1" hour o 'NoRegRead Action' = "Fail" o 'ThresholdType' = "Ratio" o For 03, 04, 07 'ThresholdValue' = "0.010" (i.e. 1%) o For 05 and 06 'ThresholdValue' = "0.005" (i.e. ½ %)

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1. Introduction

This document has been prepared in consultation with the sub-committee members of the SMSIP Joint Working Groups as a draft Validation, Estimation and Editing (VEE) Standard for further consideration by the Joint Working Group.

The OEB does not envision approving the VEE rules developed by the IESO SMSIP Working Group. The Board does expect that, at a minimum, the rules would comply with 5.3.2 and 5.3.3 of the *Distribution System Code*.

1.1 Purpose

The purpose of this document is to establish a province wide validation, estimation standard and editing guideline for Meter Read data collected for electricity smart meters in the province of Ontario.

1.2 Scope

The scope of this document is the validation and estimation and editing standards for smart metering used for the following:

- Residential or small general service consumers where the metering of demand is not required for single phase and three phase installations either self-contained or transformer type meters.
- Commercial and Industrial consumers where the metering of demand is required for single phase and three phase installations either self-contained or transformer type meters involving multiple channel and multiple data type metering.

1.3 Who Should Use This Document

This document should be used by Local Distribution Companies, Advance Metering Infrastructure Operators, and the Smart Metering Entity for use in applying the VEE services described herein.

1.4 Assumptions and Limitations

- Wholesale metering installations registered with the IESO are not subject to the VEE services described in this document.
- Net metering and the metering for all classifications of generators are outside the current scope of the MDM/R and the VEE Services described in this document.

- Missing meter read data that requires estimation or editing will not be reported by the MDM/R for customer presentation.

- The sub-committee members of the SMSIP Joint Working Groups preference would be that weather normalization factors be applied to estimated Meter Reads. This MDM/R functionality is not being anticipated in the initial implementation of the MDM/R unless directed by the Ontario Energy Board. Future stages of MDM/R implementation may support this functionality.

- VEE Services provided by the MDM/R shall apply only to Smart Meters that conform to the criteria described in the *Functional Specification for an Advance Metering Infrastructure*.

- The VEE Services described in this document shall only be applied to physical Service Delivery Points.

1.5 Conventions

The standard conventions followed for this document are as follows:

- The word “shall” denotes a mandatory requirement,
- Title case is used to highlight process or component names; and
- *Italics* are used to highlight publication, titles of procedures, letters and forms

1.6 Roles and Responsibilities

Role of the Smart Metering Entity

The role of the Smart Metering Entity will be the configuration and maintenance of VEE Services to be applied to Meter Read data transmitted to the MDM/R by LDCs across the province of Ontario. VEE Services beyond a set of default VEE Services may be configured by the MDM/R Administrator to support additional LDC needs. Any such additional VEE Services will be available to all LDCs.

Role of Local Distribution Companies

The role of the local distribution company shall be to apply the available VEE Services appropriately to all Service Delivery Points within their service territory.

LDC’s will be responsible to validate all Meter Read data that has been identified by the MDM/R as “Needs Validation or Editing” (NVE).

1.7 How This Document Is Organized

This document is organized as follows:

- **Section 2** of this document provides an overview of the Application of the Validation, Estimation, and Editing Standards; the AMI to MDM/R Interface, and MDM/R Data Collection and Reporting Services.

- **Section 3** of this document provides a description of Validation Standards for residential or small general service consumers where the metering of demand is not required and commercial and industrial consumers where the metering of demand is required including meters involving multiple channels and multiple data type metering installations.

- **Section 4** of this document provides a description of Estimation Standards for residential or small general service consumers where the metering of demand is not required and commercial and industrial consumers where the metering of demand is required including meters involving multiple channels and multiple data type metering installations.

- **Section 5** of this document provides a description of Editing Guidelines for residential or small general service consumers where the metering of demand is not required and commercial and industrial consumers where the metering of demand is required including meters involving multiple channels and multiple data type metering installations.

- **Section 6** of this document provides a description of the Billing Quantity Validation Services for residential or small general service consumers where the metering of demand is not required and commercial and industrial consumers where the metering of demand is required including meters involving multiple channels and multiple data type metering installations.

- **Section 7** of this document provides a description of the Validation, Estimation and Editing services for residential and small commercial consumers, commercial and industrial consumers where the metering of demand is required including meters involving multiple channels and multiple data type metering installations.

1.7.1 Definition of Terms used in this Document

Within this document the following words and phrases have the following meanings:

"**AMCC**" means the Advanced Metering Control Computer that is used to retrieve or receive and temporarily store Meter Reads before or as they are being transmitted to the MDM/R. The information stored in the AMCC is available to log maintenance and transmission faults and issue reports on the overall health of the AMI to the LDC.

"**AMI**" means the Advanced Metering Infrastructure, it includes the meter, Advanced Metering Communication Device (AMCD), Local Area Network (LAN), Advanced Metering Regional Collector (AMRC), Advanced Metering Control Computer (AMCC), Wide Area Network (WAN), and related hardware, software, and connectivity required for a fully functioning data collection system. An AMI does not include the MDM/R.

"AMCD" is an Advanced Metering Communication Device that is housed either under the meter's glass or outside of the meter. It transmits Meter Reads from the meter directly or indirectly to the AMCC.

"AMRC" is an Advanced Metering Regional Collector that collects Meter Reads over the local area network from the AMCD and transmits these Meter Reads to the AMCC.

"**Billing Quantity**" refers to consumption data that has been through VEE and is ready for use in billing.

"**Billing Multiplier**" is a factor that shall be applied to Meter Reads from metering installations where instrument transformers including current transformers (CT) and potential transformers (PT) are installed. For transformer type metering installations this factor shall be the product of the current transformer ratio, the potential transformer ratio and the meter multiplier. All conforming Smart Meters shall have a meter multiplier of one (1) in accordance with the Functional Specification for an Advanced Metering Infrastructure. Transformer loss factors for primary installations shall not be included in the determination of this factor.

Where no external instrument transformers are installed such as for self-contained meters this factor shall be one (1) in accordance with the *Functional Specification for an Advanced Metering Infrastructure*.

"Commercial and Industrial customers" refers to commercial and industrial consumers where the metering of demand for billing purposes is required.

"**Consumer**" or "**customer**" refers to residential or small general service consumers where the metering of demand is not required.

"**Daily Read Period**" means the 24-hour period for collecting Meter Reads, subject to the two periods during which changes to and from Daylight Savings Time take place. The Daily Read Period commences at 12:00 midnight of each day.

"**kWh**" means kilowatt-hour.

"**LDC**" means a Local Distribution Company, which is a LDC, as defined in the Ontario Energy Board Act, 1998.

"**Meter Read**" is a number generated by a meter that reflects cumulative electricity consumption at a specific point in time. (The Meter Read and related data will be reported to the MDM/R at a specific Service Delivery Point).

"**Meter Read Block**" is used by the MDM/R for validation and estimation purposes. All validation and estimation functions are based on acting upon a set of contiguous intervals bounded by a start register read and a stop register read. In some instances a Meter Read Block the data will span two or more Meter Transfer Blocks. For a Meter Transfer Block consisting of interval consumption data with a register reading at the end of a set of interval consumption data, the start register read for the Meter Read Block will be the immediately preceding (contiguous) stop register read.

"Meter Transfer Block" is a set of data transferred from an AMCC (or other system) to the MDM/R relating to meter reads for a specific Universal SDP ID. A Meter Transfer Block is a set of interval consumption data with a register reading at the end of the set of interval data, or a set of interval register reads for a number of contiguous intervals.

"**MDM/R**" means the meter data management and meter data repository functions within which Meter Reads are processed to produce Billing Quantity data and the storage of data for future use.

"**SDP**" means the Service Delivery Point at which delivery is metered or calculated. The SDP is the point at which billing occurs based on input from one or more smart meters.

"**VEE**" means validation, estimating and editing of Meter Reads to identify and account for missed and inaccurate reads used to derive billing data.

– End of Section –

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2. Application of the VEE Standards

The Validation, Estimation and Editing Standards offer a series of checks that can be performed against a Meter Transfer Block. Several of the Validation and Estimation checks have variable configurable parameters. These parameters allow for the configuration of the actions taken should the Meter Transfer Block fail the various validation and/or estimation checks.

This section provides a description of the application of these standards by the Smart Meter Entity in establishing default VEE Services or specific VEE Services necessary to support additional LDC needs.

This section also provides a description of the AMI to MDM/R Interface including the quality and completeness tests that are expected to be performed by the Advance Metering Infrastructure prior to the transmission of meter read data to the MDM/R, and MDM/R Data Collection and Reporting Services.

2.1 Application of Standards

The diversity of consumer types, load usage patterns, geographic location, and other variables within Ontario necessitate the creation of a number of VEE Services. Multiple VEE Services will provide the ability to modify the validation and estimation parameters to better meet the VEE needs of a consumer group.

Default VEE Services offered to LDCs will be administered by the Smart Metering Entity and will be available for use throughout the province via the MDM/R.

Creation, maintenance and administration of any additional LDC specific VEE Services once created by the Smart Meter Entity shall be made globally available to all LDCs via the MDM/R.

2.2 AMI – MDM/R Interface

2.2.1 Quality and Completeness Tests Performed by the AMI

It is expected that certain quality and completion tests are performed by the AMI systems prior to the Meter Read data being sent to the MDM/R. Test results are in the form of interval data flags associated with the Meter Reads, in a particular Meter Transfer Block being sent to the MDM/R. These types of tests are listed below:

- Pulse Over Flow Check;
- Test Mode Check;
- Meter Diagnostic Check;

- Reverse Energy Check;
- Time Change Check; and
- Loss and Restoration of Power

Pulse Overflow Check

Pulse Overflow conditions are normally a result of improper scaling factors within the meter, improper instrument transformer sizing or a meter hardware failure. A meter sets a Pulse Overflow flag when the energy consumption in an interval exceeds the range of the interval. This flag generally indicates a serious problem with the meter installation or the meter itself. These metering conditions must be physically investigated and corrected by the LDC.

The AMI System must be capable to analyse and identify the intervals for this condition and flag them with a “PulseOverflow” flag prior to providing the Meter Read Data to the MDM/R. The MDM/R inspects Meter Read Blocks received with this condition and validates the data, estimates the data or flags it for verification or editing by the LDC based on the VEE Service parameter.

Test Mode Check

The Test Mode condition is normally performed at the metering installation by a metering technician. This test requires the meter to be placed in a test mode and possibly have a simulated load condition applied to the meter to verify the meter’s accuracy. The AMI System identifies the interval(s) where the usage is recorded by the meter in a Test Mode and provides this information to the MDM/R. Intervals received and flagged with a “test mode” indicator will be validated, estimated or flagged for verification or editing by the LDC based on the VEE Service parameter.

Meter Diagnostic Check

The AMI System may be capable to identify intervals for various meter diagnostic problem existing prior to providing the Meter Read data to the MDM/R. The Meter Read Blocks provided to the MDM/R with such conditions may be validated, estimated or flagged for verification or editing by the LDC based on the VEE Service parameter.

Reverse Energy Check

The AMI System may be capable to identify intervals for reverse energy condition exists prior to providing the Meter Read Data to the MDM/R. The Meter Read Blocks provided to the MDM/R with such conditions may be validated, estimated or flagged for verification or editing by the LDC based on the VEE Service parameter.

Time Change Check

Time change checks are performed within the AMI system to verify that the components used for data collection are within the acceptable time thresholds as described in the, “*Functional Specification for an Advanced Metering Infrastructure*.” The Time Change Flag indicates that the meter time was adjusted during the interval and the interval may be either shorter or longer than the specified interval at which the data is to be collected. Meter Read Blocks provided to the MDM/R with time change flags may be validated, estimated or flagged for verification or editing by the LDC based on the VEE Service parameter.

Loss and Restoration of Power

Loss of power is a condition where the supply of electricity to the AMCD and/or AMRC has occurred. This failure could be as a result of a LDC distribution supply failure or the operation of an electricity disconnect prior to the AMCD and/or AMRC device.

Restoration of power is a condition where the supply of electricity to the AMCD and/or AMRC has been re-established.

The AMI system shall detect and identify the interval(s) in which a loss of power occurred and identify the interval(s) in which the restoration of power occurred. These interval flags made available to the MDM/R are required to assure accurate validation and estimation of data for each SDP.

2.2.2 Data Quality Flags Provided by the AMI

AMI systems may provide additional data quality flags that will be recognized by the MDM/R and recorded as part of the meter data record.

Data quality flags do not represent validation tests but simply set data quality flags and failure codes in the MDM/R Meter Data Database. Data quality flags are applied as part of the meter data collection process. The data quality flags that are transferred vary by AMCC type and may set corresponding MDM/R flags. In addition to the quality and completeness test flags used for validation, the MDM/R will store the following data quality flags.

Partial Data

The MDM/R inspects each interval for a partial data flag. The 'PARTIAL_INTERVAL' flag is set in the Meter Data Database of each interval for which the AMCC reports a partial data condition.

Short Interval

The MDM/R inspects each interval for a short interval flag. The 'SHORT_INTERVAL' flag is set in the Meter Data Database of each interval for which the AMCC reports the interval to be shorter than the specified interval at which the data is to be collected.

Long Interval

The MDM/R inspects each interval for a long interval flag. The 'LONG_INTERVAL' flag is set in the Meter Data Database of each interval for which the AMCC reports the interval to be longer than the specified interval at which the data is to be collected.

Data Collection Estimation

The MDM/R inspects each interval for a data collection estimation flag. The 'DC_DATA_ESTIMATION' flag is set in the Meter Data Database for each interval for which the AMCC reports the interval has been estimated outside the MDM/R as part of the data collection process. This flag sets the Validation Status to EST (estimated) and sets the Change Method to EXT (external – indicating estimation performed external to the MDM/R). Other Validation checks work normally and can re-set the Validation Status; failure codes, and estimation Change Method on failure of such tests.

2.3 MDM/R Data Collection and Reporting Services

2.3.1 Meter Read Data Validation During Loading

These services are performed immediately upon receipt of the Meter Transfer Block from either an AMCC, manual input or other system(s). The AMCC generates the Meter Transfer Block file that is transferred to the MDM/R. The MDM/R will process the files through a series of processes as outlined in the table below.

Type	Description	Pass	Fail
Syntactic Check	The structure of the file is validated against the appropriate file format for the specific AMCC.	• Acknowledgement back to LDC or AMI Operator. • Continue Processing Data.	• The LDC or AMI Operator is notified of rejected data records flagged as invalid.
Semantic Check	The content of the file is checked for validity and to determine whether a power outage, power restoration, or meter rollover has occurred.	• Continue Processing Data • Power outage, restoration, and meter rollovers are flagged	• The LDC or AMI Operator is notified of rejected data records flagged as invalid
Other Meter Read Data Loading Services			
Application of CT/PT Multiplier	Interval consumption data is multiplied by the CT/PT Multiplier set for each SDP through the synchronization process. Register reads are stored "as received" and no multiplier is applied		
Calculation of Interval Consumption from Register Reads	In the event that the AMCC only delivers register reads, the MDM/R calculates the corresponding interval consumption data prior to loading data into the Meter Data Database. Interval consumption data is stored at the same granularity of the Meter Read data as received from the AMCC (e.g. Meter Read data received at 5-minute intervals will be stored as 12 values). The register reads are also stored. The CT/PT Multiplier is applied when creating the associated interval consumption data. Register reads are stored "as received" and no multiplier is applied.		
Treatment of Missing Reads and Zero Reads	Zero reads are stored as an actual Meter Read of zero. Missing reads are detected by the MDM/R, stored as zero and flagged as 'No-Data' but may be estimated during VEE.		

Table 2-1 Pre-VEE Processes

2.3.2 Meter Read Data Transmission

The following sections describe the sets of data that may be transmitted from the various AMCC technologies to the MDM/R. These data sets are defined as Meter Transfer Blocks. Also described is the application of message validation and estimation services to the Meter Read Block as used by the MDM/R for validation and estimation.

"**Meter Transfer Block**" is a set of data transferred from an AMCC (or other system) to the MDM/R relating to Meter Read data for a specific SDP. A Meter Transfer Block is a set of interval consumption data with a register reading at the end of the set of interval data (see Figure 2-1), or a set of interval register reads for a number of contiguous intervals (see Figure 2-2).

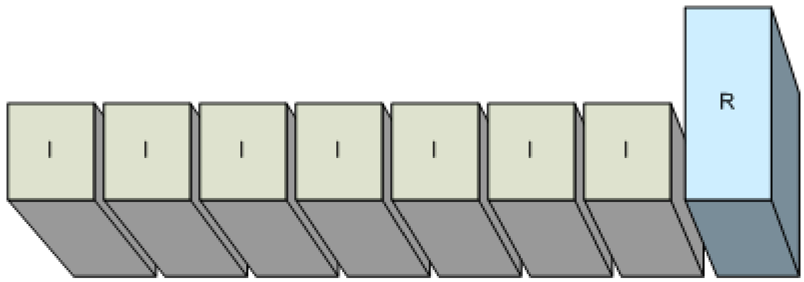

Figure 2-1 Cumulative Interval Consumption with a Stop Register Read

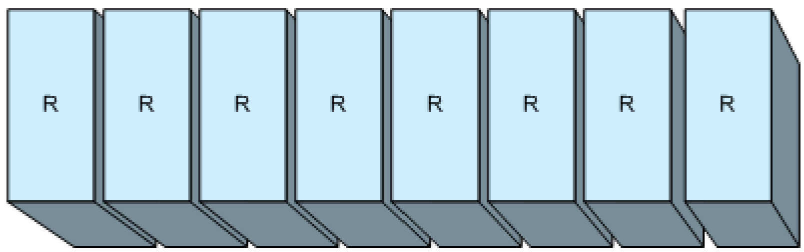

Figure 2-2 Register Reads For Each Interval

"**Meter Read Block**" is used by the MDM/R for validation and estimation purposes. Certain validation and estimation functions are based on acting upon a set of contiguous intervals bounded by a start register read and a stop register read. In some instances a Meter Read Block (see Figure 2-3) may span two Meter Transfer Blocks. For a Meter Transfer Block consisting of interval consumption data with a register reading at the end of a set of interval consumption data, the start register read for the Meter Read Block will be the immediately preceding (contiguous) stop register read.

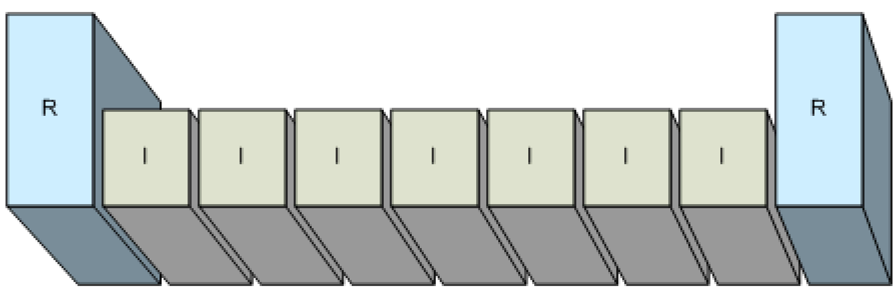

Figure 2-3 Interval Consumption with Start and Stop Register Reads

A Meter Transfer Block may be transmitted comprised of a stop register read only, with no associated interval consumption (see Figure 2-4). Such register read transmissions will be stored in the Meter

Data Database but will not trigger any validation algorithm or estimation algorithm for the estimation of the missing intervals.

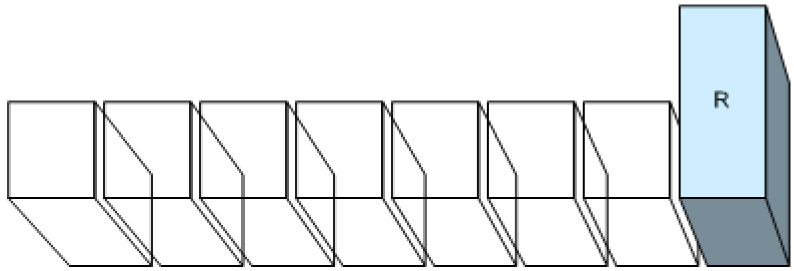

Figure 2-4 Stop Register Read Only, with No Interval Consumption

In Figure 2-5 the start register read (on the left) and subsequent interval consumption (below in grey) are stored in the MDM/R. Interval flags check; Maximum Demand Check, and Spike Check will be performed and if estimation is called for by the VEE Service, estimation will be attempted. The Sum Check will not be performed on the initial Meter Transfer Block. The new Meter Transfer Block contains a stop register read (on the right) but no interval consumption data. As with Figure 2-4 this register read transmission will be stored in the Meter Data Database but will not trigger any validation algorithm or estimation algorithm for the estimation of the missing intervals.

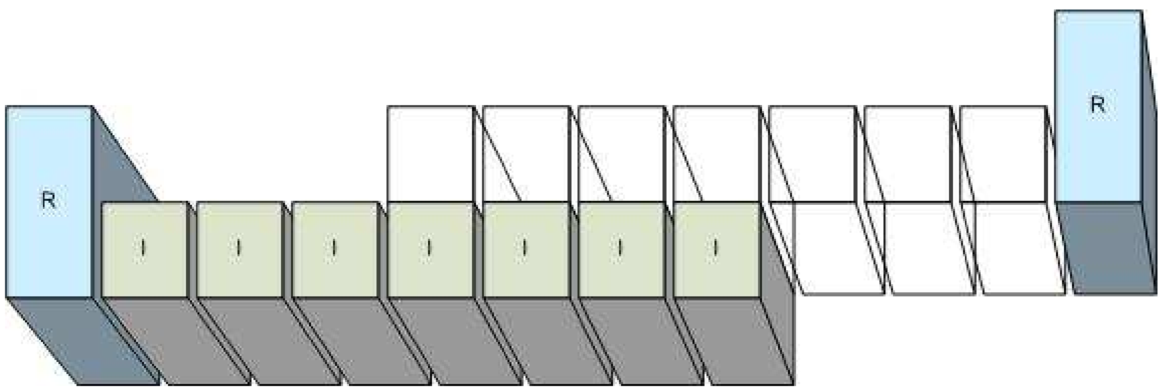

Figure 2-5 Meter Change with Incomplete Intervals

A Meter Transfer Block may be transmitted comprised of interval consumption only, with no associated stop register read (see Figure 2-6). Interval flags check; Maximum Demand Check, and Spike Check will be performed and if estimation is called for by the VEE Service, estimation will be attempted. The Sum Check will not be performed.

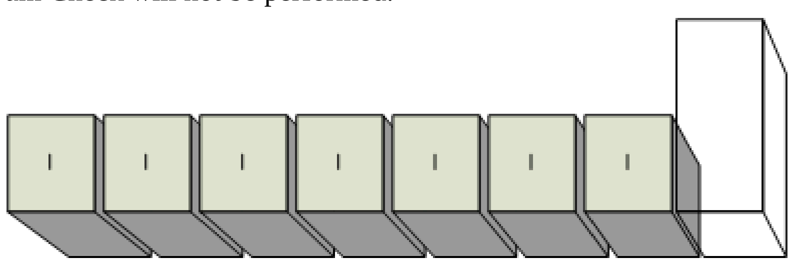

Figure 2-6 Interval Consumption with no Stop Register Read

In Figure 2-7 the stop and start register reads already exist in the MDM/R but with either no interval consumption data or perhaps estimated consumption data in between. The new Meter Transfer Block (below, grey) may provide, for example, edits to replace missing values or actual reads to replace estimated reads. This provides the LDC with the ability to send in edited meter reads or actual meter reads to fill in the gap between two register reads.

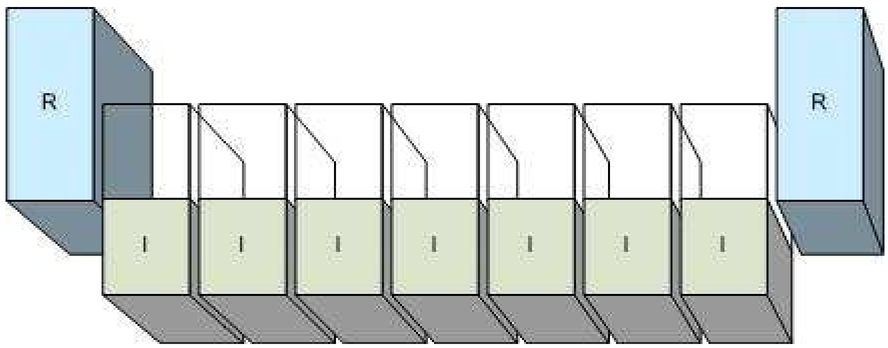

Figure 2-7 Edits Performed between Register Reads

2.3.3 Data Collection and VEE Reporting

The MDM/R provides daily reporting of the data collection processes and generates operational reports that detail the results. Complete specifications for these reports can be found in the MDM/R V1.0 Reports Technical Specifications. The data collection reports are as follows:

- DC01: Daily Read Status Report – providing a total count of meters for which data was received in the prior day segmented by AMCC type.
- DC02: Excessive Missing Reads Report – identifying meters that have failed to transmit register data for more than five days in a 10-day window.
- DC03: Interim Read Validation Failure Report – identifying *Meter Read* data files that have failed the incoming validation process for *Meter Read* data delivered to the MDM/R between midnight and the daily morning deadline for receipt of data for the prior *Daily Read Period* ‘N’.
- DC13: Final Read Validation Failure Report – identifying *Meter Read* data files that have failed the incoming validation process for *Meter Read* data delivered to the MDM/R during the entire previous day ‘N+1’.
- DC04: Missing Reads Detail Report – providing a listing of those meters for which data was not received for the most recent *Daily Read Period* ‘N’.
- DC05: Daily Data Collection Report – providing a total count of meters for which data was received in the prior day segmented by AMCC type and read age.

- DC06: Interim AMCC Data Collection Summary Exception Report – providing a summary of all exceptions encountered during the processing of *Meter Read* data files delivered to the MDM/R between midnight and the daily morning deadline for receipt of data for the prior *Daily Read Period* 'N'.
- DC16: Final AMCC Data Collection Summary Exception Report – providing a summary of all exceptions encountered during the processing of *Meter Read* data files delivered to the MDM/R during the entire previous day 'N+1'.
- DC07: Interim AMCC Data Collection Detailed Exception Report – providing a listing of all exceptions encountered during the processing of *Meter Read* data files delivered to the MDM/R between midnight and the daily morning deadline for receipt of data for the prior *Daily Read Period* 'N'.
- DC17: Final AMCC Data Collection Detailed Exception Report – providing a listing of all exceptions encountered during the processing of *Meter Read* data files delivered to the MDM/R during the entire previous day 'N+1'.

The MDM/R also provides daily reporting of the validation and estimation processes and generates operational reports that detail the results. Complete specifications for these reports can be found in the MDM/R V1.0 Reports Technical Specifications. The VEE reports are as follows:

- VE01: Interim Validation Failure Detail Report – providing a listing of all meters where Meter Transfer Block data has failed one or more of the validation checks for Meter Read data files delivered to the MDM/R between midnight and the daily morning deadline for receipt of data for the prior Daily Read Period 'N'.
- VE11: Final Validation Failure Detail Report – providing a listing of all meters where Meter Transfer Block data has failed one or more of the validation checks for Meter Read data files delivered to the MDM/R during the entire previous day 'N+1'.
- VE02: Interim Estimation Failure Detail Report – providing a listing of all meters where Meter Transfer Block data could not be estimated and the reason why for Meter Read data files delivered to the MDM/R between midnight and the daily morning deadline for receipt of data for the prior Daily Read Period 'N'.
- VE12: Final Estimation Failure Detail Report providing a listing of all meters where Meter Transfer Block data could not be estimated and the reason why for Meter Read data files delivered to the MDM/R during the entire previous day 'N+1'.
- VE03: Missing Interval Aging Report – providing a listing of those meters for which data was not received within the previous 3 calendar days.
- VE04: VEE Summary Report – providing summary number counts for the results of the validation; estimation; and verification/editing processes.

– End of Section –

3. Validation Standards

Validation is applied by the MDM/R in two ways: 1) data validation performed during loading of Meter Read data and 2) by the application of Daily Validation Services. Meter Read data validation during loading is applied to Meter Transfer Blocks received from all Smart Metering installations. The Daily Validation Services are applied in accordance with VEE Services defined for the type of consumer and metering installation. Daily Validation Services are configured to identify Meter Reads that fall outside of acceptable tolerance(s) and anomalies recorded by the meter.

The following sections describe the Meter Read data validation during loading, and the missing read checks.

- Validation Services for Residential or Small General Service Consumers, and
- Validation Services for Commercial and Industrial Consumers with the metering of demand with multiple channel metering.

3.1 Residential or Small General Service Consumers

Validation must be based on the characteristics of the data on hand. The list of checks and criteria itemized in the following sections shall be applied during validation of data collected by the AMI and transmitted to the MDM/R for consumers where the metering of demand is not required.

Validation will be performed for each Meter Transfer Block received from the AMI as part of Message Validation Services for residential or small general service consumers.

3.1.1 Message Validation Services

Validation Services are performed immediately upon completion of the Meter Read data load validation services for each applicable Meter Transfer Block. These services are performed on Meter Transfer Blocks received from the AMI or other systems. The validation checks performed on each Meter Transfer Block are referred to as message validation services.

Message validation service checks must be performed at the appropriate point in the data processing cycle of the MDM/R. Without strict adherence to the processing cycle, the validation service may fail resulting in invalid data. Some of these quality and completion checks must be performed by the AMCC and are described in section 2.2 of this document. Other validation checks within the MDM/R can be performed any time after data collection and before Billing Quantity generation. Billing Validation processes act upon the output from the Billing Quantity generation process and are described in Billing Validation Services section 6 of this document.

3.1.2 Overall Control

This parameter determines whether or not any validation and estimation is undertaken. If set to 'N' (No) then none of the following tests are undertaken. If the parameter is set to 'Y" (Yes), then all of the following tests that are enabled are undertaken.

Validation Check Sequence – Validation checks are performed in the following order:

1. Missing Intervals Check
2. Interval Flags Check
    a. Test Mode Check
    b. Pulse Overflow Check
    c. Time Change Check
    d. Meter Diagnostic Check
    e. Reverse Energy Check
3. Maximum Demand Check
4. Spike Check
5. Sum Check
6. Consecutive Zeros Check

3.1.3 Missing Intervals Check

The validation process identifies any gaps in interval consumption data within a Meter Transfer Block or between Meter Transfer Blocks and flags these gaps for Estimation or for verification/editing by the LDC based on the VEE Service parameter. Intervals for which a power outage is detected are not flagged as missing.

Power Outage Detection Within a Meter Transfer Block – This power outage detection algorithm identifies sections of missing intervals (i.e. 'NO_DATA' intervals) within a Meter Transfer Block that are part of a power outage. This algorithm for power outage detection is:

1. Within the Meter Transfer Block contiguous 'NO_DATA' intervals on either side of an "Outage" interval are flagged as 'POWER_OFF' and the 'NO_DATA' flag is cleared in these intervals.

2. An "Outage" interval is defined as:

    a. An interval with the 'POWER_OFF' flag set,
    OR

    b. An interval with the 'POWER_ON' flag set.

The "Outage" interval definition addresses data collection systems that may not set a power outage flag for an interval that contains a power restore event. A power restore event ('POWER_ON') in an interval implies that a power outage state ('POWER_OFF') was true at some point in the interval.

Power Outage Detection Between Meter Transfer Blocks – This power outage detection algorithm identifies sections of missing intervals between Meter Transfer Blocks that are part of a power outage. This algorithm for power outage detection is:

1. If the first interval of the of the current Meter Transfer block has a 'POWER_ON' flag set, get the interval record from the Meter Data Database for the last interval received prior to the start of the current Meter Transfer block

    a. If the last prior interval from the Meter Data Database has a 'POWER-OFF' flag set to 'Y', the section of missing intervals between Meter Transfer Blocks is part of a power outage. In this case set the 'POWER_OFF' flag to 'Y' and the interval value to '0' for every missing interval between the last prior interval and the start of the current Meter Transfer Block.

    b. If the 'POWER_OFF' flag is not set for the last prior interval from the Meter Data Database, the section of missing intervals between Meter Transfer Blocks is NOT part of a power outage. In this case set the 'NO_DATA' flag to 'Y' for every missing interval between the last prior interval and the start of the current Meter Transfer Block.

3.1.4 Interval Flags Check

The Interval Flags Check handles all single-interval checks – checks that can be done without comparing intervals to other intervals. This includes the Missing Intervals Check described above as well as the validation checks described below.

Test Mode Check

The MDM/R inspects each interval for a Test Mode Flag. An interval with the Test Mode flag set fails validation only if the interval consumption is non-zero. If zero usage is recorded for the intervals in which the meter was in test mode, (i.e. meter was bypassed during testing) this data is considered valid.

Many meters will register 0 interval consumption while in test mode, thus if the meter records usage in test mode, the data does not represent actual Customer consumption.

This test can be configured to validate with the failure flagged (i.e. soft failure), estimate, or require verification/editing.

Pulse Overflow Check

The MDM/R inspects each interval for a Pulse Overflow Flag. A meter sets a Pulse Overflow flag when the energy consumption in an interval exceeds the range of the interval. This flag generally indicates a serious problem with the meter installation or the meter itself.

This test can be configured to validate with the failure flagged (i.e. soft failure), estimate, or require verification/editing.

Time Change Check

The MDM/R inspects each interval for a Time Change flag. The Time Change Flag indicates that the meter time was adjusted during the interval and the interval may be either shorter or longer than the specified interval at which the data is to be collected. The Time Change flag is maintained since intervals with Time Change are not used in Demand computations.

This test can be configured to validate with the failure flagged (i.e. soft failure), estimate, or require verification/editing.

Meter Diagnostic Check

The MDM/R inspects each interval for a Meter Reset Flag. The meter read interface adaptor maps the meter diagnostic flags from each individual type of device to the Meter Reset Flag a part of the Data Collection process. (Reference MDM/R Technical Interface Specifications, Meter Read Interface – for each AMI technology.)

Meter diagnostic error flags generally indicate a serious meter problem but may not necessarily indicate that the interval data is erroneous.

This test can be configured to validate with the failure flagged (i.e. soft failure), estimate, or require verification/editing.

Reverse Energy Check

The MDM/R inspects each interval for a Reverse Rotation Flag.

This test can be configured to validate with the failure flagged (i.e. soft failure), estimate, or require verification/editing.

3.1.5 Maximum Demand Check

The Maximum Demand Check is a conditional test enabled or disabled for each specific VEE Service by a “check” product parameter.

The MDM/R compares each interval consumption value against the Maximum Demand Value specified in the VEE Service parameter. Interval values represent fully scaled kWh quantities including the CT/PT Multiplier. The Maximum Demand Value is in fully scaled kW.

The Maximum Demand Value (in kW) is divided by the number of intervals per hour (intervals/hr) providing an energy equivalent Maximum Interval Value (in kWh per interval). Each interval consumption value (in kWh) is then compared to the Maximum Interval Value. Interval consumption values greater than the Maximum Interval Value will fail the Maximum Demand Check and the ‘Maximum Demand Action’ will be performed.

This test can be configured to validate with the failure flagged (i.e. soft failure), estimate, or require verification/editing.

3.1.6 Spike Check

The Spike Check is a conditional test enabled or disabled for each specific VEE Service by a "check" product parameter.

The MDM/R may perform a spike check on each Meter Transfer Block to identify intervals with high consumption relative to the surrounding intervals. The spike check validation is performed as follows:

- Identify the highest and Nth highest interval values where N is a VEE Service parameter. The default value for N is 3.
- If the highest interval has already failed a prior validation check, then spike check is not performed.
- If the highest interval is less than or equal to the configurable Spike Check threshold, skip the spike check. The Spike Check Threshold value is specified in kWh units. The Spike Check Threshold is set in the VEE Service parameters.
- If the Nth highest interval is less than or equal to the configurable Spike Check threshold, skip the spike check. Otherwise, subtract the Nth highest interval from the highest interval and divide by the Nth highest interval. The algorithm is as follows:
  (highest interval - Nth highest interval)/Nth highest interval)
- The MDM/R will apply the following pass/fail criteria to the data set:
  - If ((highest interval - Nth highest interval)/Nth highest interval) <= threshold (a configurable value) the interval passes the spike check.
  - If ((highest interval - Nth highest interval)/Nth highest interval) > threshold (a configurable value), the interval fails the spike check and the 'Spike Check Action will be performed.

This test can be configured to validate with the failure flagged (i.e. soft failure), estimate, or require verification/editing.

3.1.7 Sum Check

The Sum Check is a conditional test enabled or disabled for each specific VEE Service by a "check" product parameter.

The Sum Check is performed after other validation checks and will only be performed if the Meter Transfer Block passes the Missing Intervals Check and all intervals have passed the previous validation tests flagged as validated (including "soft fail" intervals).

The MDM/R performs a sum check on the Meter Read Block. Should the absolute value of the Sum Check difference exceed the threshold this validation fails, and all interval records in the Meter Transfer Block will be flagged with the failure.

- The Meter Transfer Block must include at least one Register Read with a timestamp that is between the earliest and the latest interval timestamps in the Transfer block, i.e. the register read occurred during one of the intervals in the block. The Register Read with a timestamp at the end of a Meter Transfer Block is defined as the End Read. For the purposes of this

Sum Check the timestamp for the End Read is defined to be the reading at the end of the interval in which the reading was taken.

- Intermediate Register Read Conversion to End Read – A by-product of validation is that the Validator calculates the End Read from the Intermediate Register Read (IRR) value if all of the intervals between the two are valid. An Intermediate Register Read is defined as a Register Read with a timestamp that is between the earliest and the latest interval timestamps in the Transfer block. IRR conversion is performed using the following logic:
  IF:
  End Read is null AND Intermediate Register Read is null, do not perform Sum Check
  IF:
  End Read is null AND Intermediate Register Read is NOT null, calculate End Read from Intermediate Read and the sum of the valid intervals between the Intermediate register Read and the end of the Meter Transfer Block
  IF:
  End Read is not null, use End Read supplied as part of the Meter Transfer Block
- The Sum Check test will retrieve the most recent register reading and interval data from the Meter Data Database. This register read is defined as the Start Read and for the purposes of the Sum Check its timestamp is defined as the end of the interval in which if occurred.
- The Sum Check will subtract the Start Read from the End Read and compute the difference. If the value is negative the meter register has “rolled over” and 1 x 10^N will be added to the negative difference value where N is 4, 5 or 6 whichever will results in a positive value. The N reflects the number of meter register digits. For example add 100,000 to the negative difference value for a 5 dial meter.
- Sum Check failure is determined as follows. The sum of the interval consumption for intervals between the Start Read and End Read is divided by the CT/PT Multiplier and compared to the un-scaled register read difference. If the absolute value of the difference is greater than the Msg Sum Check Threshold, the ‘Msg Sum Check Action’ will be performed.

  |(∑ Interval values / CTPT Multiplier) **-** *(RR_Difference)| > Msg Sum Check Threshold*

  Note: When used with different CT/PT Multipliers, this algorithm tests that the tolerance is within the unscaled register readings. For example, if the CT/PT Multiplier was 80.0 and the Msg Sum Check Threshold was also 1.0, the Sum Check would test that the dial reading was within 1, meaning that the kWh was within 80.
- Meter Change and CT/PT Multiplier Change Detection – Because of the logic leading up to a Sum Check, it is not expected that a meter change event or CT/PT Multiplier change event would be the cause of a Sum Check failure. Nevertheless, if a sum check fails, the Validator does check for a meter change and/or CT/PT Multiplier value change event before reporting a sum check failure.
  A Sum Check failure is disregarded if a meter change or CT/PT Multiplier relationship change occurred anywhere in the time span delimited by a Start Read time and End Read time relative to the dataset being evaluated.

This test can be configured to validate with the failure flagged (i.e. soft failure), or require verification/editing. The ‘estimate’ action is not available for the Sum Check.

3.1.8 Extra-Message Checks

The Consecutive Zeros Check acts on data beyond the Meter Read data contained in a Meter Transfer Block.

Consecutive Zeroes Check

The Consecutive Zeros Check is a conditional test enabled or disabled for each specific VEE Service by a "check" product parameter.

A "Zero Interval" is defined as an interval where:

- Interval Value = 0
- NO_DATA is false (i.e. the 0 value is not the result of Missing Intervals)
- POWER_OFF is false
- POWER_ON is false

The MDM/R checks the Meter Transfer Block for consecutive zero values. The Consecutive Zeros Check is performed as follows:

IF there is at least one contiguous section of Zero Intervals in the dataset equal to or longer than 'Consecutive Zeros Threshold' THEN:

- Set 'ZER' bit in each Zero Interval FAIL_CODE
- Take action specified by 'Consecutive Zeros Action'

IF the dataset contains one or more trailing Zero Intervals, query Meter Data Database for count of adjacent later Zero Intervals. If the count of adjacent later Zero Intervals + count of leading Zero Intervals is longer than 'Consecutive Zeros Threshold' (hours) THEN:

- Set 'ZER' bit in each leading Zero Interval FAIL_CODE
- Take action specified by 'Consecutive Zeros Action'

IF the dataset contains one or more trailing Zero Intervals, query Meter Data Database for count of adjacent later Zero Intervals. If the count of adjacent later Zero Intervals + count of leading Zero Intervals is longer than 'Consecutive Zeros Threshold' (hours) THEN:

- Set 'ZER' bit in each trailing Zero Interval FAIL_CODE
- Take action specified by 'Consecutive Zeros Action'

A Consecutive Zeros Check does not flag prior or later intervals that are discovered in the Meter Data Database to be part of a consecutive zeros failure.

This test can be configured to validate with the failure flagged (i.e. soft failure), estimated, or require verification/editing.

3.2 Commercial and Industrial Consumers with metering of Demand (Multiple channel metering)

Data collection for Commercial & Industrial metering is expected to provide measurement data beyond the kWh data and associated register readings provided by metering used for Residential and Small General Service Customers where metering of demand is not required.

The MDM/R adaptors used for C&I Customers must be able to support kWh, kW, kVA, kVAh, kVAR, and kVARh along with associated registers.

3.2.1 Message Validation Services available to C&I Metering

Message validation services used for Residential and Small General Service Customers will also be available for use for C&I Customers.

3.2.2 Additions to Validation Services to Support C&I

The following validation check specific to C&I meters will be supported by the MDM/R.

kVARh Check

The kVARh check is performed to identify intervals where reactive load (kVARh) is present and active load (kWh) is not, indicating a suspicious usage pattern and possible meter malfunction. This check is only required when both kWh and kVARh are used for billing. If kVARh data is available but not used for billing, the check is optional. This check may be done on either consumption or pulse data, provided the data scaling is consistent throughout the period

– End of Section –

4. Estimation Standards

The MDM/R Estimation Standards applies a method that is operationally manageable and maintainable and is fair to Residential and Small General Service Customers where the metering of demand is not required, and Commercial and Industrial customers with the metering of demand is required.

The MDM/R Estimation Standard is consistent with the standard described in the "Ontario Energy Board, *Distribution System Code*, Last revised on June 27, 2007 (Originally Issued on July 14, 2000)" Section 5.3.2, specifically:

> "A distributor shall establish a VEE process according to local practice that is fair and reasonable and provides assurance that correct data is submitted to the settlement process."

This section provides a description of the application of the MDM/R Estimation Standards to:

- Residential or small general service consumers where the metering of demand is not required for single phase and three phase installations either self-contained or transformer type meters.
- Commercial and Industrial consumers where the metering of demand is required for single phase and three phase installations either self-contained or transformer type meters involving multiple channel and multiple data type metering.

4.1 Residential or Small General Service Customers

Estimation standards described in this section of the document refer to residential or small general service consumers where the metering of demand is not required. While other methods may arguably provide more accurate estimates the solution chosen uses historical data from a SDP to provide estimates that are representative of historical consumption at that SDP while providing computationally manageable overhead for 4.5 million meters or more.

4.1.1 Message Estimation Routines

Gaps or errors in interval data may be estimated by the MDM/R as they are identified in the validation process. Estimation for filling gaps between Meter Transfer Blocks is limited by the 'Max Estimation Days' parameter and gaps that exceed this value are not estimated. These estimations are performed on interval records marked as 'data requires estimation' by the validation processing.

Message estimation does not extend beyond the most recent Meter Transfer Block received. The Billing Validation process will call exception handling processes that will attempt use estimation to complete interval data that is missing at the end of a Billing Period. This includes extrapolation[1] of

[1] Billing Validation Extrapolation is a deferred delivery component – reference Component 27, MDM/R Change Request MCR No. 003.

interval data and associated reframing to generate complete Billing Quantities to the required End Date.

4.1.2 Linear Interpolation

If a section of data needing estimation is less than ‘Max Interpolation Minutes’ in length (e.g. 60 minutes) then this estimation uses linear interpolation to compute the interval values. If the ‘Max Interpolation Minutes’ is set to zero this method is not used.

Use point-to point linear interpolation to estimate the data using before and after endpoints, where:

1. Endpoints must be intervals with a validation status of ‘validated’ (VAL) including “soft fail” intervals. Intervals containing a power failure cannot be used as end points for linear interpolation.
2. If the section occurs in the middle of the Meter Transfer Block, the “first point” is the last valid interval before the section, and the “second point” is the first valid interval after the section.
3. If the section occurs at the beginning of the Meter Transfer Block, use the last interval from the historical data as the first point if the historical data is available and valid.

If before and after endpoints are not available, the interval(s) requiring linear interpolation will be flagged as PTS (i.e. no endpoints) with a validation status of ‘needs verification or editing’ (NVE).

4.1.3 Historic Estimation

If the section of data needing estimation is more than the ‘Max Interpolation Minutes’ and less than the ‘Max Estimation Days’ then estimation will be performed by averaging intervals from like day types to create a Daily Profile for the period to be estimated. A Daily Profile is a ranked list of valid reference days and the interval consumption value for each interval in the Daily Profile is simply the average of the interval values for the reference days.

If the section of data to be estimated exceeds ‘Max Estimation Days’ the intervals will be flagged as ‘GAP’ with a validation status of ‘needs verification or editing’ (NVE).

Use the average of selected reference days to estimate interval consumption data as follows:

- Only “validated” intervals can be used. Valid intervals are defined as those that have a validation status of VAL (including “soft fail” intervals and intervals that have been “verified” i.e. change method code ‘VER’). Estimated intervals with a validation status of (EST) cannot be used.
- Data from days with a power failure cannot be used. Power failures can cause irregular usage patterns, resulting in data that is not typical for the Customer.
- The earliest possible reference date is calculated as the ‘Oldest Like Day’ before the section of data needing estimation.
- The latest possible reference date is calculated as either:

   a. The ‘Newest Like Day’ past the last day in the section of data needing estimation, or

b. The last day of the same billing cycle as the last day in the section of data needing estimation.

- Reference days are chosen to be of the like day type that are closest chronologically to the data needing estimation, regardless of seasonal crossover. Currently, like days can include days behind an account change.[2] This may include days after the day requiring estimation. When two potential like days are equidistant from the day requiring estimation the 'before' day is selected over the 'after' day.

There are two steps to the historic estimation process and these are described below:

1) Develop an average Daily Profile for each period to be estimated:

   a) Find the 'Number Like Days' (e.g. five) "same day of the week" reference days with valid data closest in time to each section of data needing estimation based on the rules listed in the previous section. If the section needing estimation is a holiday, the "same day of the week" is the closest Sunday. Calculate the average Daily Profile for each day type to be allocated using the selected reference days. If 'Number Like Days' same day of the week are not available, calculate the average Daily Profile using fewer reference days. For example if the section of data to be estimated is on a Tuesday and the 'Number Like Days' is five, select the five closest Tuesdays. If five Tuesdays are not available select four, if not then three, then two, then one.

   b) If no "same days of the week" reference days are available, look for the 'Number Like Days' "like" days that are closest chronologically to the section of data needing estimation. For example, if the intervals needing estimation are on Tuesday, use Monday, Wednesday, and Thursday. Only use weekdays with weekdays; only use weekends with weekends; use only Sundays or holidays with holidays. Calculate the average Daily Profile using up to 'Number Like Days' reference days (e.g. from one to five as available).

   c) If there is no valid "same day of the week" or "like" reference days and 'Use Class Load Profile" is set to "N", the data may not be estimated and is flagged as NLK (NO_LIKE_DAYS) with a validation status of 'needs verification or editing (NVE).

2) Use the average Daily Profile to estimate the usage data:

   The estimated value for each interval is simply the average interval value from the calculated Daily Profile. The average interval value from the Daily Profile is considered "raw estimated data" and is subject to Register Read scaling if the 'Register Allocation' parameter is set to 'Y' for the VEE Service.

The MDM/R will normalize the representative profile so that the consumption for the Daily Read Period is the same as for the daily read profile to be estimated. The profile could at some future point also be normalized for weather factors but weather factors will not be supported unless directed by the Ontario Energy Board.

Note that this method does not assume that the historical days are a good match for the profile of the Meter Read Block being estimated and implicitly assumes that no large changes in consumption behavior have occurred. The technique generates estimates that are typical of recent behavior as opposed to trying to match historical usage to the profile of the Meter Read Block being estimated.

[2] Account Specific Historical Information Algorithm is a deferred delivery component – reference Component 35, MDM/R Change Request MCR No. 013.

4.1.4 Class Load Profile

The MDM/R supports estimation using a single specified Class Profile for each VEE Service. These Class Profiles may be applied optionally to each VEE Service. The MDM/R Administrator loads the Class Load Profiles into the appropriate interval channels in the MDM/R. One Class Load Profile channel for each VEE Service is defined.

Setting the 'Use Class Profile' parameter to "Y" enables Class Load Profile estimation. It can then be used in two situations:

- The most common intended use case of Class Load Profile estimation is as a fallback estimation option for intervals that cannot be historically estimated because of NO_LIKE_DAYS. The historical estimation algorithm will set a flag on a dataset if an interval has a NO_LIKE_DAYS failure. After the dataset has been fully processed by the historical estimation algorithm, the flag is checked, and if it is set, the ClassLoadProfiler is called to estimate all intervals in the dataset that have NO_LIKE_DAYS failures.

- Alternatively, Class Load Profile can be configured to be used instead of historical estimation, by setting the 'Number Like Days' parameter to '0'. In this case, all sections of NE (needs estimation) intervals in a dataset that are NOT linear interpolation are estimated using Class Load Profile.

Class Load Profile estimation consists of two steps described below.

1. Initialization. At the level of the section of data needing estimation, a Class Profile is initialized using the channel reference specified by the 'Class Profile Channel' parameter for the VEE Service associated with interval data being estimated; and the Start Time and End Time of the section of data needing estimation.

   a. The Class Profile is loaded for a given time period. Class Profiles are always loaded in 24-hour midnight-to-midnight time chunks (to set up for subsequent Average Daily Usage scaling). A section of data needing estimation that contains less than a full day of data will trigger a full day of Class Profile data that covers the dataset time period. A section of data needing estimation that contains intervals that span more than one day will trigger multiple days of Class Profile data to be loaded to cover all the days represented in the dataset.

   b. If the Class Profile is successfully loaded (all expected Class Profile intervals are found in the database), an attempt is made to scale the Class Profile interval values using the **Average Daily Usage** of the interval channel. The scaler sums up the interval data values in the class profile and divides by the number of days in the class profile to obtain the Average Profile Daily Usage in kWh per day. The Average Daily Usage is then obtained for the interval channel (see algorithm description below). The scaling factor is then calculated as:

      scalingFactor = Average Daily Usage / Average Profile Daily Usage

   c. If a scaling factor is successfully calculated, each interval of the "raw class profile interval data" is scaled as:

      scaledIntervalValue = rawIntervalValue * scalingFactor

2. For each interval in the section of data needing estimation obtain the estimated interval from the ClassLoadProfiler, and set the change method code based on whether the Class Profile has been scaled:

   If scaled, change method set to 'Class Load Profile, scaled with ADU' (ESE)

   If not scaled, change method set to 'Class Load Profile, unscaled' (ESD)

The **Average Daily Usage** (ADU) for the interval channel is obtained by querying the Meter Data Database for register reads, and calculating the Average Daily Usage using the first two register reads that meet the criteria for use as endpoints in the ADU calculation.

Register reads are queried over the time period delimited by the "Class Profile ADU Newest Read" (# of days) after the End Time of the section of data needing estimation, and going backwards through the "Class Profile ADU Oldest Read" (# of days) prior to the Start Time of the section of data needing estimation.

Beginning with the most recent register read and working backwards in time, the list is searched for the first pair of register read values (designated as RR1 at RR1Time; RR2 at RR2Time) that meet the following criteria:

- The register reads must be separated by at least "Class Profile ADU Min Days" full days, and

- Both register reads must have been obtained from the same meter with the same active CT/PT Multiplier value, and

- Neither of the register reads can be estimated (ESTIMATED_METHOD must be NULL).[3]

If there is a Meter or CT/PT Multiplier change between RR1Time and RR2Time, the earlier register read of the pair is re-designated as RR2 and a search is performed for an earlier register read (RR1) that meets the criteria above within time period delimited by the "Class Profile ADU Newest Read" and the "Class Profile ADU Oldest Read".

If a valid register read pair is NOT obtained by this search, the Average Daily Usage cannot be calculated and the Class Profile is not scaled.

If a valid register read pair is obtained, they are first run through the Dial Rollover algorithm to adjust for possible dial rollover between the readings, and the Average Daily Usage (ADU) in kWh per day is calculated as follows:

ADU = (((RR2 – RR1)*CTPT Multiplier) * (seconds-per-day)) / (RR2Time-RR1Time)

Loading Class Profile Data – The MDM/R Administrator loads the Class Profile data into the appropriate interval channels in the MDM/R. One Class Profile channel for each VEE Service is defined. The Class Profile data is maintained in an Interval Data channel. The standard class profile is a 60 Minute Interval Data, kWh channel. Class Profile interval data must be provided in advance of any period that is to be estimated by the Class Load Profile estimation process. This means that

[3] Estimation of Register Reads is not performed by the MDM/R.

the interval data must be provided for several weeks or months into the future. Generally a Class Profile is available for a full year.

4.1.5 Register Read Scaling

Register Read Scaling is applied to sections of intervals after they have been populated with raw estimated data using either the historical or class load profile estimation methods. Before scaling, each section of estimated intervals is first checked to determine if a meter change has occurred during the section. If so, the section is divided into meter-specific sections and each meter-specific section is scaled separately. If a meter change is detected, the algorithm checks for CT/PT Multiplier changes within the dataset time period, and the sections belonging to the different meters are scaled separately using appropriate CT/PT Multiplier values. If there is a gap between the two meter relationships, the estimated intervals in that gap are left unscaled.

Historic estimation and Class Load Profile estimation will operate with and without register reads. The VEE Service parameter “Register Allocation” determines if the register reads will be used to scale the “raw estimated data” from historical estimation or the “raw class profile interval data” from Class Load Profile estimation. When register reads are available before and after the gap being estimated and ‘Register Allocation’ is set to “Y”, the estimated interval values will be adjusted so that the sum of the intervals (actual and estimated) between the register reads is equal to the difference in register reads.

Intervals estimated using historical estimation with register read scaling are recorded in the Meter Data Database with a validation status of ‘estimated’ (EST) and a change method code ESC.

Intervals estimated using Class Load Profile estimation with register read scaling are recorded in the Meter Data Database with a validation status of ‘estimated’ (EST) and a change method code ESF.

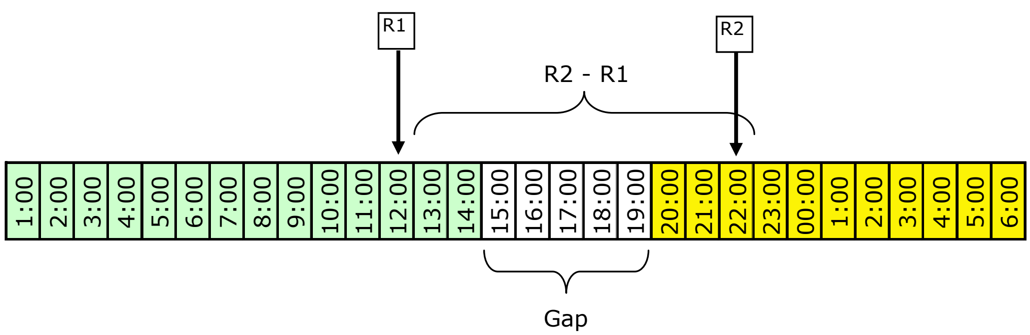

Figure 4-1 Estimation with Register Reads

As shown in Figure 4-1 register reads used in estimations are deemed to have occurred at the end of the interval in which they occurred. This assumption allows register reads to be used regardless of their alignment to the Meter Transfer Block or an interval boundary.

Although the AMCC interface requires that interval data is always accompanied by a register read, should register reads not be available on both sides of the gap being estimated or if ‘Register Allocation’ is set to “N” the ”raw estimated data” are not adjusted and are used as the estimate.

Intervals estimated using historical estimation without register read scaling are recorded in the Meter Data Database with a validation status of ‘estimated’ (EST) and a change method code ESB.

Intervals estimated using Class Load Profile estimation without register read scaling are recorded in the Meter Data Database with a validation status of ‘estimated’ (EST) and a change method code ESD.

4.2 Commercial and Industrial Consumers with metering of Demand (Multiple channel metering)

4.2.1 Message Estimation Services available to C&I Metering

The estimation algorithms used for C&I metering must require that all channels be present for estimation. In the event that one of more channels, but not all channels, are present for the same time interval, the estimation should fail. In effect, all non-register channels must be estimated simultaneously and in concert of each other. The absence of a single channel implies a serious meter failure and must be able to be configured for manual verification.

Message estimation services used for Residential and Small General Service Customers will also be available and applied to all channels for C&I metering and will include:

- Linear Interpolation, and
- Historic Estimation

Class Load Profile estimation is not proposed or expected to be required as the profiles for individual installations will vary drastically from location to location.

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5. Editing Guidelines

The MDM/R provides a Graphical User Interface (GUI) for performing manual verification and editing on Meter Read data. Upon notification of Meter Read data that Needs Verification/ Editing, the LDC will use the GUI to perform such verification or editing.

The OEB has provided some guidance for editing as described in the November 9, 2004 *Ontario Energy Board Smart Meter Implementation Plan, Draft Report of the Board For Comment*. Specifically:

> "When meter data is adjusted during the estimating process, there is always some risk that the estimated value will differ from actual consumption. Every effort must be made to ensure each estimate reflects accrual consumption to the extent possible. And to the extent possible, the risk of error should be born by the distributor."

The above principle may be applied by each LDC when editing meter read data.

5.1 Residential or Small General Service Customers

5.1.1 Manual Editing and Verification

Where actual interval consumption data is not available and automated estimation processes have not been successful, the LDC may be required to manually inspect and approve interval consumption data or to manually edit the values. The flowchart in Figure 5-1 describes this process.

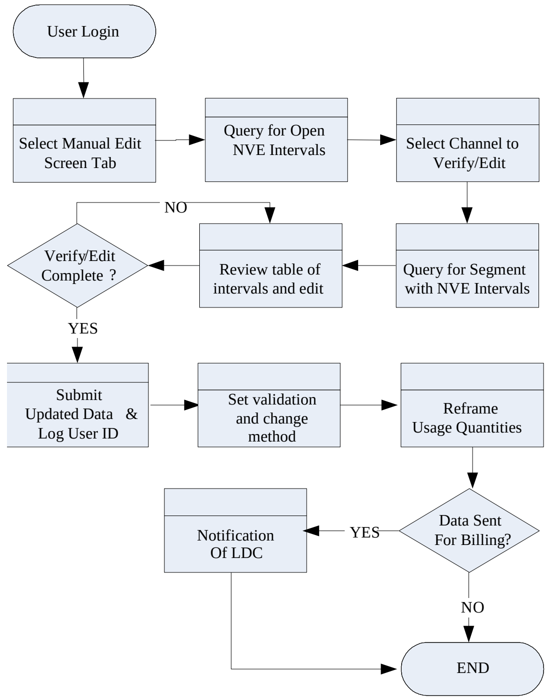

Figure 5-1 Manual Verification and Editing Flow

Locating Channels for Manual Editing

When validation checks result in interval consumption data being marked as data Needs Verification/Editing (NVE) the process automatically creates a record which contains the start and end times of the intervals that need manual verification and/or editing. An LDC user with appropriate permissions may generate a list of all such records and navigate to the interval channels that require attention.

Verifying or Editing Intervals

The LDC user may change interval consumption values in the GUI. When completed, the user submits the updated interval consumption data set. If the interval consumption data value is not changed the records are simply marked with validation status of Validated (VAL) and change method of Verified. If the interval consumption data values were changed (edited) they are marked with Validation Status set to Estimated (EST) and change method set to Edited (EDT). Intervals that are verified or edited in this process are updated in the Meter Data Database. The previous interval consumption data records are moved to the Prior Version table to maintain interval history.

Updating Billing Quantities After Editing

Channels that have been manually verified or edited in this process will be automatically reframed in order to update or complete the values in the Meter Data Database Usage table. Reframing is triggered as the interval consumption data version is updated. The LDC is notified where Billing Quantities have already been sent to the LDC based on prior interval consumption data versions.

5.2 Commercial and Industrial Consumers with Metering of Demand (Multiple channel metering)

5.2.1 Editing Support for C&I Metering

The editing functionality for meter data received from C&I metering must support the editing of all channel data (e.g.: kW, kVA, kVAR, kVAh and kVARh) simultaneously on the same screen.

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6. Billing Validation Services

Billing Validation takes place as Billing Quantities are assembled for delivery to the LDC or its agent as defined by the Data Delivery Service. Billing Validation is configured as part of the overall configuration of a Data Delivery Service including association with each VEE Service.

Billing Validations are performed on the data prior to producing Billing Quantity data. The Billing Validation process includes performing a sum check on the Billing Quantities over the period for which Billing Quantities are being provided.

The Billing Validation process will call exception handling processes that will attempt to use estimation to complete interval data that is missing during the Billing Period. This includes extrapolation[4] of interval data and associated reframing to generate complete billing quantities to the required End Date of the billing period. The extrapolation capability will be implemented consistent with the recommendation of the members of the SMSIP Joint Working Groups.

The Check Sum validation on Billing Quantity data will be performed by the MDM/R. SDPs identified as having this flag will be reported to the LDC to investigate and resolve.

6.1 Residential or Small General Service Customers

6.1.1 Billing Validation Sum Check

Prior to delivery of Billing Quantities for each SDP, the MDM/R performs the billing period validations. The Billing Validation Sum Check is configured as part of the Data Delivery Service parameters including association with a VEE Service. The MDM/R will perform the following billing validation tests once per billing request, as the Billing Quantities are prepared for export.

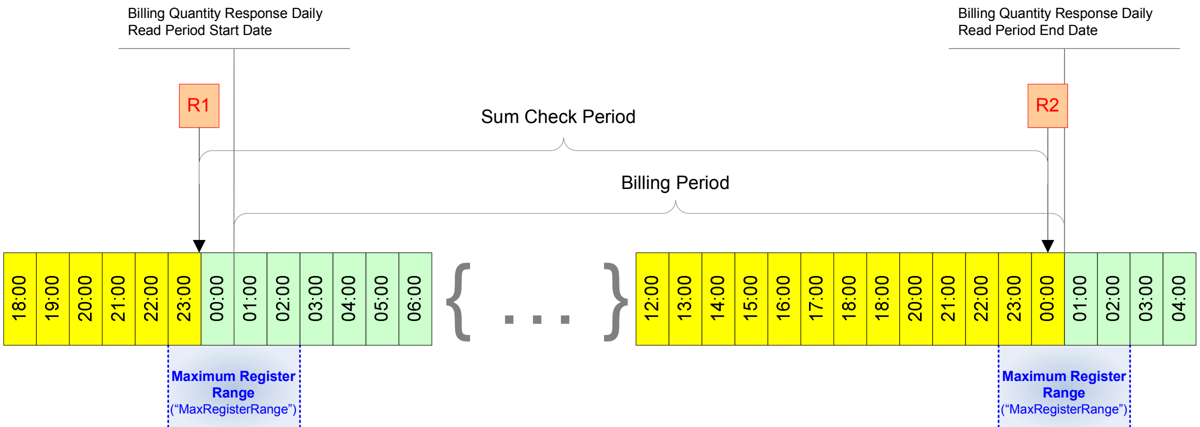

Figure 6-1 Billing Validation Sum Check on Billing Period

[4] Ibid Footnote No. 1.

The Billing Validation Sum Check is performed by comparing the total consumption of the Billing Quantity Response with the difference between the register read values nearest to the start and end points of the billing period as shown in Figure 6-1. Discrepancies may be the result of inaccuracies in manual meter data verification or editing activities.

The Billing Validation Sum Check accounts for the meter multiplier and applicable CT and VT ratios assigned to the SDP through synchronization (CT/PT Multiplier attribute) and meter register rollover and meter changes (using the First and Last Meter register readings taken at the time of the meter change and communicated through the synchronization process). The Billing Validation Sum Check requires two register readings. The first must be within 'MaxRegisterRange' hours of the Start of the billing period, the second within 'MaxRegisterRange' hours of the End of the billing period. If these register values are not available the Billing Validation Sum Check may be marked as a Billing Validation Sum Check failure or Billing Validation Sum Check skipped.

If the difference calculated above is greater than the 'ThresholdValue' for the VEE Service the Billing Validation Sum Check has failed.

The Billing Validation Sum Check 'ThresholdValue' is set specifically for the Data Delivery Service associated with each VEE Service. The threshold value above which the Billing Validation Sum Check fails may be expressed for each Data Delivery Service as one of:

1. 'Ratio' – the Sum Check is determined by comparing the absolute value of the total Billing Quantity consumption subtracted from the register reads difference divided by the register read difference to an allowable ratio i.e. the 'ThresholdValue', or
2. 'Value' – the Sum Check is determined by comparing the absolute value of the total Billing Quantity consumption subtracted from the register reads difference to a maximum kWh value i.e. the 'ThresholdValue'.

The register read difference (RR2 – RR1) is determined by RR2Time within the 'MaxRegisterRange of the Billing Quantity Response End Date and RR1Time within the 'MaxRegisterRange' of the Billing Quantity Response Start Date.

The threshold value when using the threshold type 'Ratio' is expected to be set at or below the error permitted under the dispute provisions of the Electricity and Gas Inspection Regulations. When using the threshold type 'Value' the threshold value is expected to be the maximum value of one interval period in kWh.

The Billing Validation Sum Check process accounts for CT/PT Multiplier when comparing the difference between the register read values and the total consumption of the Billing Quantity Response.

Billing Quantities for SDPs that fail the Billing Validation Sum Check may still be reported but the record will be flagged with the Billing Validation Sum Check failure code, alternatively the Billing Quantities may be nullified and the record(s) reported with the Billing Validation Sum Check failure code. The Billing Validation Sum Check is performed as soon as the billing process acquires complete data for the billing period in order to provide the LDC the opportunity to address sum check failures prior to the close of the billing window as defined by the 'LatestReportDays' parameter of the Billing Quantity process.

6.2 Commercial and Industrial Consumers with Metering of Demand (Multiple channel metering)

Billing validation services used for Residential and Small General Service Customers will also be available for use for C&I Customers.

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7. VEE Services

7.1 Overview of Message Validation and Estimation

Figure 7-1 illustrates the high-level flow of the message validation and message estimation processes. The initial step in the process is to determine the VEE Service that is to be used for the Meter Transfer Block. The process flow is then as follows:

1) Message Validation Checks - Interval consumption data in the Meter Transfer Block is checked against the criteria defined in the VEE Service parameters. Each interval within the Meter Transfer Block is assigned an outcome. The four outcomes supported are:

   a) Validated – the consumption in the interval passed all tests and is acceptable for billing and recorded with a validation status of ‘validated’ (VAL) in the Meter Data Database.

   b) Validate/Flag – the consumption in the interval has failed some validations but is acceptable for billing – these are soft validation failures. This data is flagged as having failed validations and recorded with a validation status of ‘validated’ (VAL) in the Meter Data Database. Soft validation failures are recorded as flag and failure codes on each interval record.

   c) Estimate – the consumption in the interval is incomplete or has failed validation, this data is passed on for automated estimation. This information will be recorded with a validation status of ‘needs estimation’ (NE) in the Meter Data Database but will not be made available for billing purposes until estimation is completed. These are hard validation failures.

   d) Verify/Edit – the consumption in the interval that is incomplete or has failed validation checks configured for manual verification or editing, this data is recorded with a validation ststus of ‘needs verification or edit’ (NVE) in the Meter Data Database pending manual processing. This information will not be made available for billing purposes until verification and editing is completed. These are hard validation failures.

2) Message Estimation Routines – Interval consumption data that has failed validation as incomplete (e.g. missing intervals) or having failed validation tests configured for estimation may be estimated according to processes defined by the VEE Service parameters. Register reads are not estimated. Estimated interval consumption data is then recorded with a validation status of ‘estimated’ (EST) in the Meter Data Database and flagged with a Change Method code indicating the type of estimation performed. Estimated interval consumption data is available for framing and the production of Billing Quantities.

3) Manual Verification or Edit – Consumption values for intervals that requires manual intervention is recorded with a validation status of ‘needs verification or edit’ (NVE) in the Meter Data Database. This data remains in this state and is not usable for billing until manual verifications or edits have been completed.

4) Interval consumption data for which the VEE Service is “No Validation” is recorded with a validation status of ‘not validated’ (NV) in the Meter Data Database and made available for billing.

5) Validated data; validated/flagged data; estimated data; verified or edited data, and ‘not validated’ data is available for daily Framing and the production of Billing Quantities.

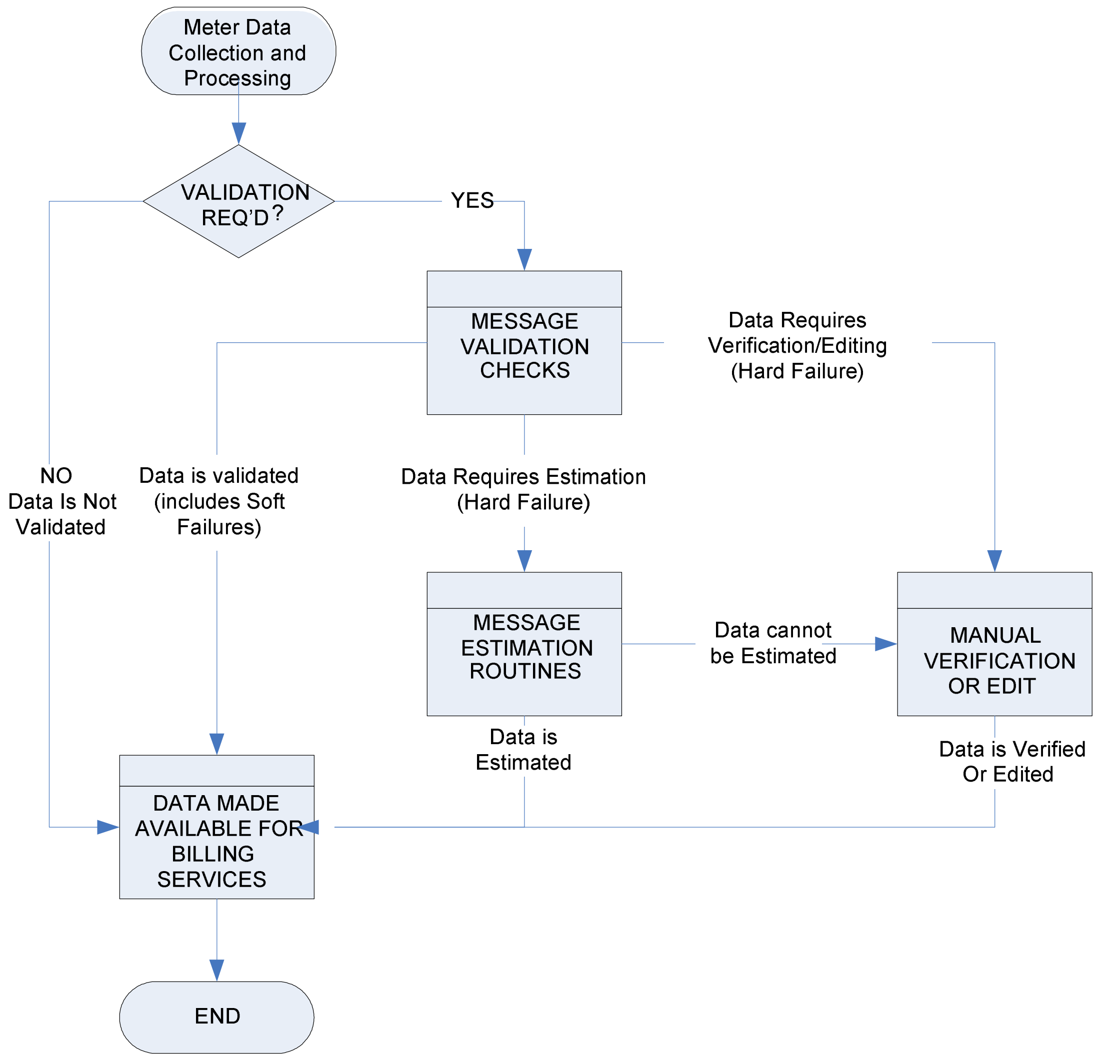


Figure 7-1 VEE Sequence as Meter Transfer Block is Received

7.1.1 Message Validation Checks

Table 7-1 below provides the parameters and descriptions for the message validation checks that are undertaken against each Meter Transfer Block. The columns in the table have the following meanings:

- **Validation Checks –** the nature of the validation test or check
- **Parameter –** the parameter that is set when the VEE Service is configured
- **Valid Value** – the allowable values of the parameter. For parameters labeled as 'Action' these are the values available for configuration to set the action when the validation check is deemed to have failed.

- **Description** – description of the parameter.

For each of the validation checks where an action is taken (as noted in the Parameter column in Table 7-1) one possible outcome is available based upon the configuration value chosen. Up to three configurable values may be available:

- **Validate/Flag –** Upon validation test failure interval consumption data is acceptable for billing. This data is flagged as having failed validations and stored in the Meter Data Database. These soft validation failures are recorded and reported to the LDC.
- **Estimate –** Upon validation test failure interval consumption data will not be made available for billing. This data is passed on for automated Estimation. These failures are recorded and reported to the LDC.
- **Verify/Edit –** Upon validation test failure interval consumption data will not be made available for billing. This data requires manual verification or editing and is saved in the Meter Data Database for manual processing. These failures are recorded and reported to the LDC.

All validation checks are undertaken for each interval, i.e. the process does not stop on encountering the first failure.

Validation Checks	Parameter	Valid Value	Description
Overall Control	Validation Enabled	Y/N	Indicates whether any validation or estimating is to be performed. If 'Y' validation is enabled If 'N' validation is disabled
Interval Flags Check			
Missing Intervals	Missing Intervals Action	Validate/Flag Estimate Verify/Edit	Indicates action to be taken for missing intervals. Flagged in the Meter Data Database as 'NO_DATA' and displayed in the GUI as 'Y' in the 'NoData' field.
Test Mode	Test Mode Action	Validate/Flag Estimate Verify/Edit	Indicates action to be taken on reporting of a test mode condition by the AMCC. Flagged in the Meter Data Database as 'TEST_MODE' and displayed in the GUI as 'Y' in the 'TestMode' field.
Pulse Overflow	Pulse Overflow Action	Validate/Flag Estimate Verify/Edit	Indicates action to be taken on reporting of a pulse overflow condition by the AMCC. Flagged in the Meter Data Database as 'PULSE_OVERFLOW' and displayed in the GUI as 'Y' in the 'Overflow' field.

Validation Checks	Parameter	Valid Value	Description
Time Change	Time Change Action	Validate/Flag Estimate Verify/Edit	Indicates action to be taken on reporting of a time change by the AMCC. Flagged in the Meter Data Database as 'TIME_CHANGE' and displayed in the GUI as 'Y' in the 'TimeChg' field.
Meter Diagnostic	Meter Reset Action	Validate/Flag Estimate Verify/Edit	Indicates action to be taken on reporting of a diagnostic error by the AMCC. Flagged in the Meter Data Database as 'METER_RESET' and displayed in the GUI as 'Y' in the 'MtrDiagError' field.
Reverse Energy	Reverse Rotation Action	Validate/Flag Estimate Verify/Edit	Indicates action to be taken on reporting of reverse rotation by the AMCC. Flagged in the Meter Data Database as 'REVERSE_ROTATION' and displayed in the GUI as 'Y' in the 'RevEnergy' field
Calculation Based Checks			
Maximum Demand	Maximum Demand Check	Y/N	Indicates whether to perform the maximum demand check on each interval. If 'Y' maximum demand is enabled If 'N' maximum demand is disabled
	Maximum Demand Action	Validate/Flag Estimate Verify/Edit	Indicates action to be taken if maximum demand check fails. Upon failure stored in the Meter Data Database as a bit sum 'FAIL_CODE' decimal value = 64 and displayed in the GUI as a decimal sum under 'FailCode'.
	Maximum Demand Value	Min: 0 Max: n/a Units: kW	Maximum demand value in kW for an interval
Spike Check	Spike Check	Y/N	Indicates whether to perform a spike check on the Meter Transfer Block. If 'Y' spike check is enabled If 'N' spike check is disabled
	Spike Check Action	Validate/Flag Estimate Verify/Edit	Indicates action to be taken if a spike check fails. Upon failure stored in the Meter Data Database as a bit sum 'FAIL_CODE' decimal value = 1 and displayed in the GUI as a decimal sum under 'FailCode'.

Validation Checks	Parameter	Valid Value	Description
	Spike Check Threshold	Min: 0 Max: n/a Units: kWh	Minimum value in kWh of highest interval required to perform spike check
	Spike Check Ratio	Min: 0.0 Max: n/a	Maximum ratio of highest to Nth highest interval value to pass spike check.
	Second Peak Rank	Min: 2 Max: n/a	2,3,4, … 'n' the order of the interval value to use in the spike check ratio test – e.g. 2nd highest value, 3rd, 4th, etc.
Sum Check	Msg Sum Check	Y/N	Indicates whether to perform a sum check on the Meter Transfer Block. If 'Y' sum check is enabled If 'N' sum check is disabled
	Msg Sum Check Action	Validate/Flag Verify/Edit	Indicates action to be taken on failure of sum check in a Meter Transfer Block. Upon failure stored in the Meter Data Database as a bit sum 'FAIL_CODE' decimal value = 2 and displayed in the GUI as a decimal sum under 'FailCode'.
	Msg Sum Check Threshold	Min: 0 Max: n/a Units: kWh	The threshold value for a Meter Transfer Block in kWh for which the Sum Check test will fail. This is a value in kWh before the CT/PT Multiplier.
Extra-Message Checks			
Consecutive Zeros	Consecutive Zeros Check	Y/N	Indicates if the consecutive zeros check is to be performed If 'Y' consecutive zeros is enabled If 'N' consecutive zeros is disabled
	Consecutive Zeros Action	Validate/Flag Estimate Verify/Edit	Indicates action to be taken on failure of consecutive zeros check. Upon failure flagged as 'ZER' on Reports VE01 and VE11.
	Consecutive Zeros Threshold	Number of intervals	Number of consecutive intervals with zeros allowed. NOTE: The specification of the threshold value as a number of intervals requires that a different VEE Service be defined for meters of different interval length.

Table 7-1 Message Validation Check Parameters and Descriptions

7.1.2 Message Estimation Routines

Gaps or errors in interval consumption data may be estimated by the MDM/R as they are identified in the validation process. Estimation for filling gaps between Meter Transfer Blocks is limited by the 'Max Estimation Days' parameter and gaps that exceed this value are not estimated.

Estimation does not extend beyond the most recent Meter Transfer Block received. The LDC is responsible for manually editing any Meter Read data where the Meter Transfer Blocks are not complete to the end of the billing period.

These estimations are performed on intervals recorded by the validation process with a validation status of 'NE' in the Meter Data Database.

Table 7-2 provides the parameters and descriptions for the message estimation that will be undertaken for intervals in each Meter Transfer Block that have been recorded as needing estimation. The columns in the table have the following meanings:

- **Estimation –** the nature of the estimation routine
- **Parameter –** the parameter that is set when the VEE Service is configured
- **Valid Value –** the allowable values of the parameter
- **Description –** description of the parameter.

Estimation Routine	Parameter	Valid Value	Description
Linear Interpolation	Max Interpolation Minutes	Min: 0 Max: n/a Units: minutes	Maximum number minutes that may be estimated using linear interpolation. Set to zero if linear interpolation is not allowed.
Overall Control	Max Estimation Days	Min: 0 Max: n/a Units: days	Maximum number of consecutive days that may be estimated either using Historic (Like Days) or Class Load Profile estimation.
	Register Allocation	Y/N	Determines if Historic estimations and/or Class Load Profile estimations are scaled using Register Reads at the start and end of the Meter Transfer Block.
Historic Estimation	Oldest Like Day	Min: 0 Max: n/a Units: days	Specifies the oldest day of historical data that may be used in historic estimation. The date established by this parameter is calculated in 24-hour increments relative to the Start Time of the first interval of a Meter Transfer Block needing estimation.

Estimation Routine	Parameter	Valid Value	Description
	Number Like Days	Min: 0 Max: n/a Units: days	Specifies the preferred (and maximum) number of reference days to use in calculating an historical estimation. Note: Setting this value to '0' effectively switches Historical estimation off. A '0' value is used when only Class Load Profile estimation is to be used for a particular VEE Service.
	Newest Like Day Method	'Newest Like Day' or 'Billing Cycle'	Provides for days after the day being estimated used as reference days. 'Newest Like Day' – use newer like days up to a 'Newest Like Day Limit' 'Billing Cycle' – use newer like days within a billing cycle.
	Newest Like Day Limit	Min: 0 Max: n/a Units: days	Used when 'Newest Like Day Method' is set to 'Newest Like Day'. Specifies the latest day of data that may be used in historical estimation. The date established by this parameter is calculated in 24-hour increments relative to the End Time of the last interval of a Meter Transfer Block needing estimation.
Class Load Profile	Use Class Profile	Y/N	Indicates if Class Load Profile estimation is to be performed. If 'Y' Class Load Profile is enabled If 'N' Class Load Profile is disabled
	Class Profile ADU Min Days	Min: 0 Max: n/a Units: days	Specifies the minimum separation between Register Reads used in calculating Average Daily Usage for Class Profile scaling
	Class Profile ADU Oldest Read	Min: 0 Max: n/a Units: days	Specifies the oldest day of Register Read data that may be used when calculating Average Daily Usage for Class Profile scaling
	Class Profile ADU Newest Read	Min: 0 Max: n/a Units: days	Specifies the latest day of Register Read data that may be used when calculating Average Daily Usage for Class Profile scaling
	Class Profile Channel	Channel Reference	If 'Use Class Profile' is set to "Y" this parameter must reference a valid channel containing reference interval data

Table 7-2 Message Estimation Routine Parameters and Descriptions

7.1.3 Validation and Estimation Outcomes

The MDM/R VEE Services generate meta-data relating to each specific interval consumption value and this meta-data is stored against interval records in the Meter Data Database. Table 7-3, Daily VEE Outcomes, lists the four validation statuses used to identify the state of an interval. Each state is further defined by the method used to modify an interval value and the validation test that failed. All Change Method Codes are recorded for each interval consumption value. Validation Failure Codes are set for all the VEE checks that fail for each interval.

Interval Validation Status	Change Method Codes	Validation Failure Code
NO VALIDATION (NV): No validation performed, data may be used as permitted.	**NULL**: Interval value not changed.	Not applicable
VALIDATED (VAL): Interval has been validated and is available for billing and other uses.	**NULL**: Interval value not changed. **VER**: Interval has been manually reviewed and verified for submission to billing.	Failure code(s) from validation failures as indicated in Table 7-1 NOTE: Failure code on validated interval is a Warning or Soft error
ESTIMATED (EST): Interval was estimated and is available for billing and other uses.	**ESA:** Interval value estimated using linear interpolation **ESB**: Interval value estimated using Historic estimation without Register Read scaling **ESC**: Interval value estimated using Historic estimation with Register Read scaling **ESD**: Interval value estimated using Class Load Profile estimation without scaling **ESE**: Interval value estimated using Class Load Profile estimation scaled using Average Daily Usage from register reads **ESF**: Interval value estimated using Class Load Profile estimation with Register Read scaling **ESG**: Interval value estimated using extrapolation **EDT:** Interval value has been manually edited. **EXT:** Interval value was estimated by an external system	Failure code(s) from validation failures as indicated in Table 7-1

NEEDS VERIFICATION/EDITING (NVE): Interval requires manual verification or editing and is not available for billing or other uses.	**NULL:** Null pending manual edit or verification then Validation Status changed to VAL or EST.	Failure code(s) from validation failures as indicated in Table 7-1

Table 7-3 VEE Outcomes

7.1.4 Billing Validation Sum Check

Table 7-4 provides the parameters and descriptions for the Billing Validation Sum Check that will be undertaken against each Billing Quantity Response. The columns in the table have the following meanings:

- **Validation Check** – the nature of the validation check
- **Parameter** – the parameter that is set when the VEE Service is configured
- **Valid Value** – the allowable values of the parameter
- **Description** – description of the parameter

Validation Check	Parameter	Valid Value	Description
Billing Validation Sum Check	BillingSumCheck	Y/N	Indicates whether to perform the Billing Validation Sum Check on the computed Billing Quantity. If ‘Y’ sum check is enabled If ‘N’ sum check is disabled
	BillingSumCheckFail Action	‘Value’ OR ‘null’	Upon Billing Validation Sum Check failure: If set to ‘Value’ will provide Billing Quantity Response with computed values and error code If ‘null’ will provide Billing Quantity Response with ‘null’ values and error code
	MaxRegisterRange	Min: 0 Max: n/a Units: hours	Maximum period in hours to search for the register reads nearest the: Billing Quantity Response Daily Read Period Start Date and Billing Quantity Response Daily Read Period End Date

Validation Check	Parameter	Valid Value	Description
	NoRegRead Action	'Skip' OR 'Fail'	Action to take if register readings are not available. If 'Skip' Billing Validation Sum Check is not performed If 'Fail' Billing Validation Sum Check fails upon failure to find register reads
	Sync Mapping Code	Char (2) Specific usage: 01, 02, 03 … 30	The VEE Service to which the Data Delivery Service is to be associated.
	ThresholdType	'Ratio' OR 'Value'	The type of Billing Sum Check: If set to 'Ratio', a percentage based sum check is performed. If set to 'Value', a threshold based sum check is performed.
	ThresholdValue	Min: 0 Max: n/a Value of form: Number (1,3)	Threshold at which sum check passes or fails. If 'ThresholdType' is set to: 'Ratio' – then a percentage allowed for the sum check difference expressed as a ratio of the register read difference and the total Billing Quantity, e.g. 1% is 0.010 'Value' – then a value in kWh allowed for the actual sum check difference

Table 7-4 Billing Validation Sum Check Parameters and Description

7.2 VEE Services for Residential or Small General Service Customers

A VEE Service refers to a specific validation configuration in combination with a specific set(s) of estimation algorithms. A set of default VEE Services will be created that will enable Ontario LDCs to choose the VEE Services that are most appropriate for their consumers yet still provide a level of standardization across the province. The default VEE Services will be:

VEE Service, No Validation

This VEE Service does not perform any validation checks. This could be used when new SDPs are established in the MDM/R and the quality of data has not yet stabilized. This will allow for the collection of interval data in the MDM/R to be used for future estimation processes but will not create unnecessary notifications to the LDC until the data quality has stabilized. The SDPs using this VEE

Service will typically not be set to send Billing Quantities to the LDCs CIS system as the Meter Read data has not been validated.

VEE Service, No Estimation

This VEE Service could be used for any SDP where no automatic estimation is required. Any missing Meter Read data for a SDP using this VEE Service will require manual estimation or editing.

VEE Service, Residential

This VEE Service shall be used for the majority of residential consumers.

VEE Service, Residential – Electric Heat

This VEE Service can be used for residential electric heat consumers. These consumers typically display very unbalanced usage patterns between seasons.

VEE Service, Transformer Type

This VEE Service can be used for transformer type SDPs. These SDPs generally have a higher level of usage and the presence of Voltage and/or Current Transformers with a CT/PT Multiplier greater than 1 (one) require the need to have unique thresholds on some of the validation checks.

VEE Service, Small General Service

This VEE Service can be used for high usage consumers. This VEE Service has higher threshold values in the maximum demand validation check.

VEE Service, Seasonal

This VEE Service can be use for consumers that have no usage for extended periods of time.

Table 7-5 provides the configuration parameters applied for each of the default VEE Services described above. The configuration parameters for each default VEE Service are considered initial values. The efficacy of the configuration for each VEE Service will be demonstrated during testing and initial integrated operation of the MDM/R and AMI systems. The configuration for each VEE Service may be updated as the result of ongoing testing and operation of the Ontario Smart Metering System.

Parameter	No Validation	No Estimation	Residential	Residential – Electric Heat	Transformer Type	Small General Service	Seasonal
Sync Mapping Code	01	02	03	04	05	06	07
MESSAGE VALIDATION CHECKS							
Validation Enabled	N	Y	Y	Y	Y	Y	Y
Interval Flags Check							
Missing Intervals Action	N/A	Verify/Edit	Estimate	Estimate	Estimate	Estimate	Estimate
Test Mode Action	N/A	Validate/Flag	Validate/Flag	Validate/Flag	Validate/Flag	Validate/Flag	Validate/Flag
Pulse Overflow Action	N/A	Verify/Edit	Verify/Edit	Verify/Edit	Verify/Edit	Verify/Edit	Verify/Edit
Time Change Action	N/A	Validate/Flag	Validate/Flag	Validate/Flag	Validate/Flag	Validate/Flag	Validate/Flag
Meter Reset Action	N/A	Verify/Edit	Verify/Edit	Verify/Edit	Verify/Edit	Verify/Edit	Verify/Edit
Reverse Rotation Action	N/A	Validate/Flag	Validate/Flag	Validate/Flag	Validate/Flag	Validate/Flag	Validate/Flag
Maximum Demand Check							
Maximum Demand Check	N/A	Y	Y	Y	Y	Y	Y
Maximum Demand Action	N/A	Validate/Flag	Validate/Flag	Validate/Flag	Validate/Flag	Validate/Flag	Validate/Flag
Maximum Demand Value	N/A	50 kW	15 kW	25 kW	35 kW	50 kW	25 kW
Spike Check							
Spike Check	N/A	N	Y	Y	Y	Y	Y
Spike Check Action	N/A	N/A	Validate/Flag	Validate/Flag	Validate/Flag	Validate/Flag	Validate/Flag
Spike Check Threshold	N/A	N/A	7.5 kWh	15 kWh	20 kWh	25 kWh	7.5 kWh
Spike Check Ratio	N/A	N/A	50	50	50	50	50
Second Peak Rank	N/A	N/A	3	3	3	3	3
Sum Check							
Msg Sum Check	N/A	Y	Y	Y	Y	Y	Y
Msg Sum Check Action	N/A	Validate/Flag	Validate/Flag	Validate/Flag	Validate/Flag	Validate/Flag	Validate/Flag
Msg Sum Check Threshold	N/A	0.25 kWh	0.25 kWh	0.25 kWh	0.25 kWh	0.25 kWh	0.25 kWh
Consecutive Zeros Check							
Consecutive Zeros Check	N/A	Y	Y	Y	Y	Y	Y
Consecutive Zeros Threshold	N/A	336[5]	336	336	336	336	4380[6]
Consecutive Zeros Action	N/A	Validate/Flag	Validate/Flag	Validate/Flag	Validate/Flag	Validate/Flag	Validate/Flag

[5] Based on a one (1) hour interval meter and 14 days

[6] Based on a one (1) hour interval meter and 6 months

Parameter	No Validation	No Estimation	Residential	Residential – Electric Heat	Transformer Type	Small General Service	Seasonal
Sync Mapping Code	01	02	03	04	05	06	07
MESSAGE ESTIMATION ROUTINES							
Max Interpolation Minutes	N/A	0	0	0	0	0	0
Overall Control – Historic Estimation and Class Load Profile Estimation							
Max Estimation Days	N/A	0	15	15	15	15	45
Register Allocation	N/A	N	Y	Y	Y	Y	Y
Historic Estimation							
Oldest Like Day	N/A	0	30	30	30	30	0
Number Like Days	N/A	0	5	5	5	5	0
Newest Like Day Method	N/A	Newest Like Day	Newest Like Day	Newest Like Day	Newest Like Day	Newest Like Day	Newest Like Day
Newest Like Day Limit	N/A	0	1	1	1	1	1
Class Load Profile Estimation							
Use Class Load Profiles	N	N	N	N	N	N	Y
Class Profile ADU Min Days	N/A	N/A	N/A	N/A	N/A	N/A	5
Class Profile ADU Oldest Day	N/A	N/A	N/A	N/A	N/A	N/A	30
Class Profile ADU Newest Day	N/A	N/A	N/A	N/A	N/A	N/A	1
Class Profile Channel	N/A	N/A	N/A	N/A	N/A	N/A	Internal Siebel Ref
BILLING VALIDATION SUM CHECK							
BillingSumCheck	N	N	Y	Y	Y	Y	Y
BillingSumCheckFail Action	N/A	N/A	Value	Value	Value	Value	Value
MaxRegisterRange	N/A	N/A	1	1	1	1	1
NoRegRead Action	N/A	N/A	Fail	Fail	Fail	Fail	Fail
Sync Mapping Code	01	02	03	04	05	06	07
ThresholdType	N/A	N/A	Ratio	Ratio	Ratio	Ratio	Ratio
ThresholdValue	N/A	N/A	0.010	0.010	0.005	0.005	0.010

Table 7-5 Default VEE Services Configuration

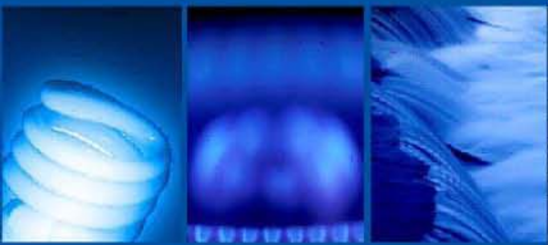
7.3 VEE Services for Commercial and Industrial Consumers with metering of Demand (Multiple channel metering)

VEE Services for C&I customers will be configured based on existing and additional validation, estimation and editing functionality developed for the MDM/R and after consultation with the SMSIP Working Group VEE Sub-Committee.

– End of Document –

util-assist

utility strategic operational assistance



CornerstonE
Hydro Electric Concepts

Request for Proposal

Wide Area Network Solution / Services

RFP 2008-1205

December 5, 2008

Section 1: Background

1.1 Introduction

To create a conservation culture in Ontario and make the Province a North American leader in energy efficiency, the Government has taken action to facilitate a number of key initiatives, including the introduction of flexible, time-of-use pricing for electricity, and a target reduction in Ontario's energy consumption of 5% by 2007.

The CHEC Group consists of the following 14 electricity Local Distribution Companies:

Centre Wellington Hydro Ltd.	Orangeville Hydro Limited
COLLUS Power Corp.	Orillia Power Distribution Corporation
Grand Valley Energy Inc.	Parry Sound Power Corporation
Innisfil Hydro Distribution Systems Ltd.	Rideau St. Lawrence Distribution Ltd.
Lakefront Utilities Inc.	Wasaga Distribution Inc.
Lakeland Power Distribution Ltd.	Wellington North Power Inc.
Midland Power Utility Corporation	Westario Power Inc.

These utilities collectively represent over 110,000 endpoints across Ontario. CHEC members have been working collaboratively through the planning and preparation stages for the Smart Meter Initiative. CHEC is an association of electricity distribution utilities modeled after a cooperative to share resources and proficiencies as the Ontario electricity industry continues its transformation.

The mission of CHEC is to be recognized as the premier LDC Cooperative in the province, by meeting or exceeding member expectations through the sharing of services, opportunities, knowledge and resources. The values of CHEC include the sharing of resources, both intellectual and technical, enabling members to deliver value to their customers and shareholders ensuring competitiveness in the marketplace. Together the mission and value statements represent lofty but attainable goals for CHEC members. Collaboratively CHEC represents over 110,000 residential end points in Ontario and is comprised of the following member utilities:

1.2 Provincial Context for Project

To create a conservation culture in Ontario and make the Province a North American leader in energy efficiency, the Government has taken action to facilitate a number of key initiatives, including the introduction of flexible, time-of-use pricing for electricity, and a targeted reduction in Ontario's energy consumption of 5% by 2007.

As part of its energy conservation effort, the Ontario government has achieved their commitment to implement 800,000 smart meters by 2007 and is now focused on the replacement efforts of all existing meters (5 million) with smart meters by 2010. Phase One utilities have fulfilled their commitments to install 1 million smart meters by Dec 31, 2007 which assisted the government in exceeding their interim goal of 800,000 by Dec 31, 2007.

The underlying premise behind the provincial mandate to install these meters is to educate customers on their consumption habits and implement new rate structures that will encourage load shifting and conservation of energy, thereby reducing the requirement for increased power generation capabilities.

1.3 CHEC's Approach to Smart Metering

With respect to the Provincial government's Smart Metering Initiative, CHEC has taken a collaborative approach to becoming educated on this mandate by working with other Ontario utilities and advocacy groups.

Along with satisfying the provincial mandate of measuring "how much electricity a customer uses each hour of the day, and to use that data to charge customers an energy price that varies depending on when the electricity was consumed" (OEB Smart Meter Plan; January 26, 2005; page i); CHEC will also implement the Smart Meter Network to improve overall efficiency within member service territories. Real time connectivity with the end use consumer through the installed networks will allow for improvements in the maintenance and management of the distribution network (i.e. improved outage management and restoration) and the utilization of existing infrastructure (e.g. Fiber) where available, will allow for cost effective implementation of these systems.

Through the authorized London Hydro RFP process, CHEC has successfully procured Smart Meters to accommodate their deployment commitments. The following CHEC members will be deploying the Elster EnergyAxis AMI Network (total meters = (approximately) 43,400).

Utility	Meters	Utility	Meters
Centre Wellington Hydro Ltd.	4,986	Rideau St. Lawrence Distribution Ltd.	4,635
Lakeland Power Distribution Ltd.	7,232	Wellington North Power Inc.	2,759
Midland Power Utility Corporation	5,473	Westario Power Inc.	14,682
Parry Sound Power Corporation	2,651		

Details relevant to WAN considerations have been provided within Section 3.2 *AMI System Deployed*. These CHEC members (heretofore referred to as CHEC) will now begin concentrating on establishing a long term relationship with a WAN service provider which will cost effectively provide communication capabilities between the installed regional collectors, and the back office data management systems.

The attached documentation sets out the procedural and technical requirements for the submission of proposals to Cornerstone Hydro Electric Concepts (CHEC), for its AMI WAN connection requirements as per the enclosed specifications; as well as the substantive contractual terms that govern the relationship between parties upon the award of the contract.

CHEC hopes to evaluate Bidders as objectively as possible with the end goal of selecting the best-fit service provider for a WAN solution, thereby allowing CHEC to achieve their goals, as well as those of the provincial Smart Meter mandate. CHEC have chosen to accomplish this objective through a partnership approach. Some components of service that will be required include:

- Hardware Procurement
- Installation and Commissioning
- Ongoing Maintenance

The Ministry of Energy (MoE), in their *Functional Specification For An Advanced Metering Infrastructure Version 2* (dated July 5, 2007, provided for reference as Appendix "A"); Section 2.3, *Performance Requirements* require that at minimum, 98% of all daily reads must be successfully collected, with the intention of providing this data to the centralized Meter Data Management / Repository (MDM/R) by 5 am. The centralized MDM/R is owned and operated by the Independent Electricity System Operator (IESO). CHEC is therefore interested in AMI WAN service providers which can reliably deliver the collected data according to these timelines. CHEC has provided further information regarding collected data in Section 3.4 *Collector Configuration (CI)*.

1.4 Smart Meter Terminology

For the purposes of this procurement process, and within this Request for Proposal document, CHEC has opted to utilize the terminology as defined by the Ministry of Energy in their *Functional Specification For An Advanced Metering Infrastructure Version 2* (dated July 5, 2007), Section 3, *Definitions.* For reference, this document has been included herein as Appendix "A".

1.5 Key Dates

Below is the expected timeline that CHEC will be following during the evaluation of available WAN solutions. CHEC reserves the right to adjust these dates as needed. All Bidders will be notified if any of the following dates are altered. As can be seen, it is the intention of CHEC to make its decision by January 30, 2009.

RFP released by CHEC:	**December 5, 2008**
Bidder Response with Intention to Bid:	**December 10, 2008**
In Person Q&A Meeting:	**9:00 a.m. – 12:00 p.m. December 15, 2008**
Final Questions Due:	**December 17, 2008**
Answers to Questions:	**December 22, 2008**
Closing Time (RFP Due):	**3:00 p.m. Eastern Time, January 2, 2008**
RFP Decision:	**January 30, 2009**
Anticipated Start Date:	**April 1, 2009**

Section 2: Instruction to Bidders

2.1 Bid Documents

This Request for Proposals (RFP), establishes the system products and services that CHEC wishes to acquire. This bid document is the basis upon which CHEC seeks firm proposals from selected Bidders and upon which proposals will be evaluated. The documents are:

1) This RFP (a .pdf document), including Appendices that are integral to it
2) CHEC_WANRFP_PricingSheet_Dec2008.xls, a Microsoft Excel workbook. This file allows for entry of pricing information, as well as the Statement of Understanding required by Section 2.8 *Statement of Understanding*, and will heretofore be referred to as the Pricing Spreadsheet.

2.1.1 Pricing Spreadsheet

The following tabs are included within the Pricing Spreadsheet:
1) CHEC_WANRFP_Section2.8: This tab requires completion by the Bidder, and will act as their compliancy statement according to the requirements of Section 2.8 *Statement of Understanding*
2) Pricing_Option1: This tab requires completion by the Bidder
3) Pricing_Option2: This tab is optional and only requires completion by the Bidder should they feel that the Pricing provided in Option 1 is not representative of the most cost effective option available (see Section 6: *Price Submission Requirements* for more details).

2.2 Intention to Bid

Recipients of this RFP are asked to inform CHEC of their intention to bid by completing the template form found in Section 2.20 *Proposal Forms*, and by submitting this form by the date shown in Section 1.5 *Key Dates*. Recipients that express intention to bid will be included in all correspondence (if any) during the bidding process.

2.3 Submission Requirements

1) A complete proposal will consist of one (1) original and five (5) copies of each of
   a) The proposal forms (as provided in Section 2.20 *Proposal Forms*, and
   b) The Bidder's Response document (including all associated attachments).
2) The Pricing spreadsheet (CHEC_WANRFP_PricingSheet_Dec2008.xls) and a soft copy of all of the above forms and documents should also be provided on one CD. The Pricing and Compliancy spreadsheet will allow for the Bidder to enter their pricing information in a standard format, as well as allow the vendors to attest to their company's compliancy with the RFP requirements. **As per 2.4 *Proposal Format Instructions*, any hard copies of the pricing submission should be submitted in a separate envelope, marked "PRICE OFFER".**
3) The required format of the Bidder's Response document is outlined in Section 2.4 *Proposal Format Instructions*.
4) The original hard copy shall be clearly identified as "ORIGINAL"; the remainder (i.e. five copies) shall be marked as "COPY". In the event of discrepancy between the copies of the Response, the one marked "ORIGINAL" shall prevail. Each Bidder's Response shall consist of the required documents with the required number of copies of all commercial information, including pricing, terms and conditions and exceptions (if applicable). Faxed or late proposals will not be accepted. Proposals must be sealed and marked clearly quoting the proposal number referred to on the cover sheet of the proposal documents. The use of any means of delivery of a proposal shall be at the risk of the Bidder.

5) CHEC shall not be liable for, nor shall it reimburse any Bidder for costs incurred in the preparation of proposals, or any other services or samples that may be requested as part of the evaluation process.
6) The Proposal Forms shall be signed under the Corporate Seal of the Bidder, by the duly authorized signing officer(s). All submitted pages shall be initialled by such officer(s).

2.4 Proposal Format Instructions

Where information has been requested through this RFP, the Bidder's Response should clearly indicate the RFP section number that the Response pertains to. The Bidder's Response should be organized according to the following sections:

1) Section 1 of the proposal will contain the Bidder's Executive Summary, no more than two pages in length that introduces the Bidder and highlights key features of the proposal.
2) Section 2 of the Proposal **should be provided in a separate envelope which has been clearly marked "PRICE OFFER".** This section will contain the summary pages pertaining to the Price Offer, contained within the Pricing Spreadsheet. The Bidder's detailed itemized pricing information for all goods or services is to be contained within the Pricing and Compliancy Spreadsheet which is to be included with the Response in its entirety as well as within this section. Any alternative pricing offers may also be included within the Pricing Spreadsheet, by adding tabs as needed. All pricing shall be expressed in Canadian currency, exclusive of taxes. If your originating currency is not Canadian, the currency exchange that was used to calculate the price in Canadian currency is to be provided.
3) Section 3 of the proposal will contain the Statement of Understanding that is included within the Pricing Spreadsheet as the tab entitled "CHEC_WANRFP_Section2.8" which will serve to satisfy the requirements of Section 2.8 *Statement of Understanding*.
4) Section 4 of the proposal will contain all requested information regarding the Bidder (CHEC RFP Section 4: *Bidder Company Information*) in the order presented in this document, with the numbering used in this document.
5) Section 5 of the Bidder's proposal will contain the requirements of Section 5 of this RFP Document (Section 5: *AMI WAN Solution Technology Requirements*), in the order presented in this document, with the numbering used in this document.
6) Any Bidder wishing to provide additional information other than what is requested in this proposal document must place such additional information in Section 6 of the Bidder's response which should be marked Supplementary Information. Any Additional Information or any unsolicited value-added alternatives may, in CHEC's absolute discretion, be given due consideration, or not.

2.4.1 Sample Responses to Demonstrate Format

Within the section or subsection heading an indicator has been included to specify whether the Bidder should provide information pertaining to the functionality of their product/service (with regards to the section requirements), or a statement of compliancy AND information pertaining to the functionality of their product with respect to the requirement of the section. Where no indicator is included, a response is not required.

(I)	When an (I) has been included with the section heading, CHEC requires Information regarding the proposed system's functionality, and the methodology utilized to satisfy the RFP requirement.
(C)	When a (C) has been included with the section heading, CHEC requires a statement of compliancy from the vendor. Within the proposal documentation, the Bidder is required to state the compliancy with the requirement by stating Fully Compliant, Partially Complaint, or Not Compliant.

(CI) When a (CI) has been included with the section heading, CHEC requires both a statement of compliancy, and Information regarding the proposed functionality, and the methodology utilized to satisfy the RFP requirement.

In Section 2.4 *Proposal Format Instructions* subsections 4 and 5, it has been specified that the order and numbering used within this document be retained. A sample has been provided here.

4.1 Financial / Business Stability (I)

1. What is the current size (number of employees), turnover rates for last three (3) years, and location(s) of the bidder's company?

Bidder's Functionality Statement: Vendor X currently employs 600 employees. Of the 100 office and management staff, 37 are within the Operations division providing ample redundancy and support to effectively manage this project. Vendor X's head office is located in . . . Turnover is considered low at 3%; we attribute this to an effective Safety and Training program (1 week) in which employees receive ample safety training as well as introduction to the company incentive program which has been seen to improve morale . . .

5.2 AMI WAN Coverage (CI)

It is CHEC's intention to utilize one service provider for AMI WAN coverage. It is therefore expected that the bidder will be capable of ubiquitous coverage across CHEC service areas, as described in Section 3.3 Deployment Territories. If the bidder cannot support all the use cases on their network, and will utilize the capacity of another carrier in order to provide service across all of CHEC's service territories, it is requested that the bidder identify and describe any off-net network elements, and the level of control over these carrier in the event of a critical service interruption. The Service Level agreements and assurances between the bidder and the off-net service provider should be discussed.

Bidder's Statement of Compliancy: Fully Compliant

Vendor X has reviewed the coverage maps provided by CHEC, and can state with certainty that ubiquitous coverage can be provided negating the requirement for any off-net service providers. As a result the information provided regarding Breach Notification, Security Updates, System Updates, Unwanted Traffic, and Service Level Agreements unconditionally applies to the proposed infrastructure.

2.5 Adjustments / Substitutions

1) A proposal may be altered by a Bidder only by submitting another proposal at any time up to the Closing Time. Adjustments by telephone, facsimile, telegram or letter to a proposal already submitted will not be considered. The last proposal received by CHEC's designee shall supersede and invalidate all proposals previously submitted by the Bidder for this RFP.
2) During the period prior to the Closing Time, changes made by CHEC to the proposal documents will be issued by CHEC to the Bidders as written addenda. The Bidder shall list in its proposal all addenda that were considered in the preparation of its proposal.
3) No substitutions or deviation from the Specifications, Proposal Form or General Conditions of Contract will be permitted without CHEC's approval in writing.

2.6 Complete Bid

Bidders are requested to submit bids that are complete and unambiguous without the need for additional explanation or information. CHEC reserves the right to make a final determination as to whether a bid is acceptable or unacceptable solely on the basis of the bid as submitted, and proceed with bid evaluation without requesting further information from any Bidder. If CHEC deems it desirable and in its best interest, CHEC may, in its sole discretion, request from any Bidder or Bidders additional information clarifying or supplementing any submitted bid.

2.7 Clarifications

Upon the issuance of this RFP to Bidders, and continuing through the submission date, all questions or other communications with CHEC shall be by email only, with CHEC's authorized representative:

Mr. James Douglas
Util-Assist Inc.
chec@util-assist.com

CHEC will respond to the question in writing, with both the question and Response provided to each Bidder that has declared intention to bid. No Response will be made to questions submitted after December 10, 2008.

2.8 Statement of Understanding

It is a requirement of this RFP document, that Bidders submitting proposals for evaluation complete a Statements of Understanding which will attest to the Bidder's understanding of:

1) The Scope of Work as explained in Section 3: *Project Overview*, and associated subsections which describe:
   a) CHEC's AMI Performance requirements,
   b) CHEC members' Service Territories,
   c) The Bidder's requirement to interface to the chosen AMI,
   d) The Bidder's requirement to supply the modem hardware.

2.9 Post Bid Meeting

CHEC reserves the right to invite any or all Bidders to make an in-person presentation regarding the proposed AMI WAN solution. CHEC may request Bidder's assistance in arranging visits to other installations where Bidder has deployed the solution.

2.10 Withdrawal of Proposal

Bidders will be permitted to withdraw their proposal unopened after it has been submitted if such a request is received by the designee of CHEC in writing, prior to the Closing Time.

2.11 Bid Inconsistencies

Any provisions in Bidder's proposal that is inconsistent with the provisions of this Request for Proposals, unless expressly described in the proposal as being exceptions, are deemed waived by the Bidder. In the event the order is awarded to Bidder, any claim of inconsistency between the proposal and this RFP will be resolved in favour of this RFP unless otherwise agreed to in writing by CHEC.

2.12 Bidder's Statement of Understanding

1) The Bidder acknowledges that it has carefully examined, understands and accepts the proposal documents, has carefully examined the requirements contained in the proposal documents and hereby submits an offer according to the requirements set forth in this proposal.
2) It is understood that this proposal, if it has not been withdrawn in accordance with Section 2, subsection 2.10 *Withdrawal of Proposal* of the Proposal Instructions, is irrevocable and shall remain open for acceptance by CHEC for a period of ninety (90) working days following the opening of the proposals.
3) It is further understood by the Bidder that if CHEC accepts its proposal, then the Bidder (Vendor) is bound by the Contract and agrees to provide the goods and/or services upon the terms and conditions of the Contract.
4) The Bidder acknowledges and agrees that all quantities shown in the proposal documents are approximate only. Quantities may be subject to increase, decrease, or total deletion in the event that CHEC determines in its absolute discretion that such change is required.
5) While CHEC has used considerable efforts to ensure an accurate representation of information in this Request for Proposal, the information contained in this Request for Proposal is supplied solely as a guideline for Bidders. The information is not guaranteed or warranted to be accurate by CHEC, nor is it necessarily comprehensive or exhaustive. Nothing in this Request for Proposal is intended to relieve Bidders from forming their own opinions and conclusions with respect to the matters addressed in this Request for Proposal.

2.13 Proposal Evaluation

1) All proposals shall be opened after the Closing Time in the presence of CHEC Representative or another individual designated to open the proposals by CHEC. The opening will not be public.
2) In determining the contract award, the lowest proposal will not necessarily be accepted, and CHEC reserves the right to accept or reject any or all proposals in its absolute discretion. Further, proposals may be accepted or rejected in total or in part.
3) The Evaluation Committee will review proposals and will then carry out interviews with selected Bidders for clarification as required.
4) It is anticipated that a written contract will be negotiated immediately after the successful Bidder has been notified. If a contract cannot be negotiated within thirty (30) days of notification, CHEC may, at its sole discretion at any time thereafter, terminate negotiations with that Bidder and either negotiate a contract with the next qualified Bidder or choose to terminate the Request for Proposal process and not enter into a contract with any of the Bidders.

2.14 Award of Contract

1) The Bidder acknowledges that CHEC reserves the right, privilege, entitlement and absolute discretion, and for any reason whatsoever to:
   a) Cancel this Request for Proposals at any time, either before or after the Closing Time;
   b) Accept a proposal which is not the highest scoring proposal submission, or reject a proposal that is the highest scoring proposal even if it is the only proposal received;
   c) Accept the proposal deemed most favourable to the interests of CHEC or that may provide the greatest value advantage and benefit to CHEC based upon but not limited to price, ability, quality of work, service, past experience, past performance and qualification;
   d) Accept or reject any and all proposals, whether in whole or in part;
   e) Award any part of any proposal; or
   f) Accept or reject any unbalanced, irregular, or informal proposals.

2) The Bidder acknowledges that CHEC will evaluate proposals using an internal scoring method as referenced in section 2.18 *Proposal Evaluation Criteria* and other criteria which CHEC deems relevant, even though such criteria may not have been disclosed to the Bidder. By submitting a proposal, the Bidder acknowledges CHEC's rights under this section and absolutely waives any right, or cause of action against CHEC and its consultants, by reason of CHEC's failure to accept the proposal submitted by the Bidder, whether such right or cause of action arises in contract, negligence, or otherwise.
3) Contract award, if any, will be communicated by written notification from CHEC to the successful Bidder. The successful Bidder, if any, in the presence of the designate, must sign the Contract Agreement in triplicate (3), within seven (7) Working Days of written notification of acceptance.
4) Bidders whose proposals have been rejected by CHEC will be notified within thirty (30) days of the award date.
5) The successful Bidder shall provide CHEC with a designated inside customer service representative. Any disputes and/or queries with respect to the Contract will be directed to CHEC representative, whose decisions with respect to any matter under dispute shall be final and binding.

2.15 Freedom of Information

Proposals submitted to CHEC become the property of CHEC and, as such, are subject to the *Freedom of Information and Protection of Privacy Act*, R.S.O. 1990, c. F.31, as amended.

2.17 Ownership of Data

CHEC shall own all data collected by the system. Data collected by the system shall not be used for any purpose without the approval of CHEC.

2.18 Proposal Evaluation Criteria

CHEC will evaluate proposals using an internal scoring method that weights various parameters to give the CHEC Smart Meter Team insight into the strengths of each proposal relative to CHEC's needs. The CHEC internal scoring method values the following proposal attributes (order of presentation does not reflect priority):

Figure 1 Proposal Evaluation Criteria

Proposal Evaluation Criteria	Section	% Total Points
Project Overview	**3**	
Bidder Information	**4**	
AMI WAN Solution Technical Requirements	**5**	
AMI WAN Solution Overview	**6**	
AMI WAN Coverage		
Project Management		
AMI WAN Safety Standards		
AMI WAN Solution Installation		
Value Added Services		
Section 3 through 5 inclusive:		**40%**
Pricing Weighting:		**60%**
Total		**100%**

Along with the bidder's company information, and statements of understanding regarding the project, the technical answers to section 5 will represent 40% of the total weighting of the RFP. Pricing submitted will represent 60% of the total weighting of the RFP. Vendors will be selected for further discussion based on the Team's judgment, developed using the scoring method.

2.19 Payment

When the Supplier has completed all work in accordance with the terms of the contract documents, the Supplier shall submit to CHEC a request for final payment. The request for final payment shall constitute a waiver of all claims by the Supplier except for claims specifically listed in the request. CHEC will make payment within thirty (30) days of receipt of a request for payment.

Supplier's submission of its request for final payment shall constitute its warrant that the Supplier has to the best of its knowledge fully completed all work included in the Contract and has fully paid for labour, materials, equipment, services, taxes and all other costs and expenses resulting from this Contract.

2.20 Proposal Forms

Within this section, there are two forms required for submission. The first form is found in Section 2.20.1 *Intention to Bid Form*; the intention of this form is to allow the vendor to provide a standard email Response to CHEC designee to notify CHEC of the Bidder's intent to respond to the RFP.

2.20.1 Intention to Bid Form

The procedure to be utilized for this form is to copy and paste the following content into an email, and send the email to:

chec@util-assist.com

according to the time line as established by Section 1.5 *Key Dates*.

INTENTION TO BID NOTIFICATION FORM

PROPOSAL NO. 2008-1205

Intention to Bid:
Please allow this email to represent "__Insert Company Name Here____" intention to respond to the CHEC group RFP 2008-1205.

Contact for communication regarding bid: __________________________________
Contact phone number: __________________________________
Contact email address: __________________________________

We acknowledge the requirement for our WAN solution to, at minimum, NOT inhibit CHEC's requirements to meet the Ministry of Energy's minimum functional requirements as outlined in the document *Functional Specification For An Advanced Metering Infrastructure Version 2* (dated July 5, 2007). Our proposal will include the required compliance statements and documents to properly express our ability to meet these requirements. We also acknowledge the Submission Deadline is 3:00 PM Eastern Time on January 2, 2008.

2.20.2 RFP Submission Form

The procedure to be utilized for this form is to print the following pages to be included with the RFP submission, which should be addressed to:

Mr. Eric Kussen
Midland Power Utility Corporation
16984 Hwy 12, PO Box 820
Midland, Ontario
L4R 4P4

according to the time line as established by Section 1.5 *Key Dates*.

Cornerstone Hydro Electric Concepts

Proposal Number: **2008-1205**

FOR: AMI WAN Solution and Services

THIS PROPOSAL IS SUBMITTED BY:____________________

ADDRESS:

TELEPHONE: FAX NO.:

BIDDER G.S.T. No.:

PERSON(S) SIGNING ON BEHALF:____________________________(print)

POSITION(S) OF THE PERSON(S):__________________________________(print)

To Cornerstone Hydro Electric Concepts, Hereafter called "Owner":

I/WE ____________________________________ the undersigned declare:

1. THAT no Person(s), Firm or Corporation other than the one whose signature(s) of whose proper officers and the seal is or are attached below has any interest in this proposal or in the contract proposed to be taken.

2. THAT this proposal is made without any connections, knowledge, comparison of figures or arrangements with any other company, firm or person making a proposal for the same work and is in all respects fair and without collusion or fraud.

   THE Bidder insures that no Owner and or employee of the Owner, is, or has become interested, directly or indirectly, as a contracting party, partner, stockholder, surety or otherwise howsoever in or on the performance of the said contract, or in the supplies, work or business in connection with the said contract, or in any portion of the profits thereof, or of any supplies to be used therein, or in any monies to be derived there-from.

3. THAT the several matters stated in the said proposal are in all respects true.

4. THAT I/WE have carefully examined the requirement(s), as well as all the Instruction to Bidders, Project Overview, AMI WAN Solution Technical Requirements, Proposal Forms, and Appendices relating thereto, prepared, submitted and rendered available by the Owner and hereby acknowledge the same to be part and parcel of any contract to be let for the work therein described or defined.

5. THAT I/WE do hereby propose and offer to enter into a contract to deliver all work as described or implied therein including in every case freight, duty, exchange, G.S.T. and P.S.T. in effect on the date of the acceptance of proposal, and all other charges on the provisions therein set forth and to accept in full payment therefore, the sums calculated in accordance with the actual measured quantities and unit prices set forth in the proposal herein.

6. THAT Addendum/Addenda No. ___ to ___ inclusive relate to the said contract and Bidder hereby accepts and agrees to the same as forming part and parcel of the said contract.

7. THAT additions or alterations to or deductions from the said contract, if any, shall be made in accordance with the prices stated in the Schedule of Items of Unit Prices in strict conformity with the requirements of the Contract.

8. THAT this offer is irrevocable and open to acceptance until the formal contract is executed by the awarded Bidder for the said requirement(s) or ninety (90) working days, and unit prices for as long as stated elsewhere in the document, whichever event first occurs and that the Owner may at any time within that period without notice, accept this proposal whether any other proposal has been previously accepted or not.

9. THAT the awarding of the contract, by the Owner is based on this submission which shall be an acceptance of this proposal.

10. THAT I/WE also understand that the Owner reserves the right to accept or reject all or part of this proposal or any other and also reserves the right to accept other than the lowest proposal.

The undersigned affirms that he/she is duly authorized to execute this proposal.

PROPONENT'S SIGNATURE AND SEAL:

NAME: ______________________________ ______________________________
(Please Print) (Signature)

POSITION: ______________________________

WITNESS
NAME: ______________________________ ______________________________
(Please Print) (Signature)

POSITION: ______________________________

(If Corporate Seal is not available, documentation should be witnessed)

DATED AT THE ____ THIS ________
(City/Town) (Day)

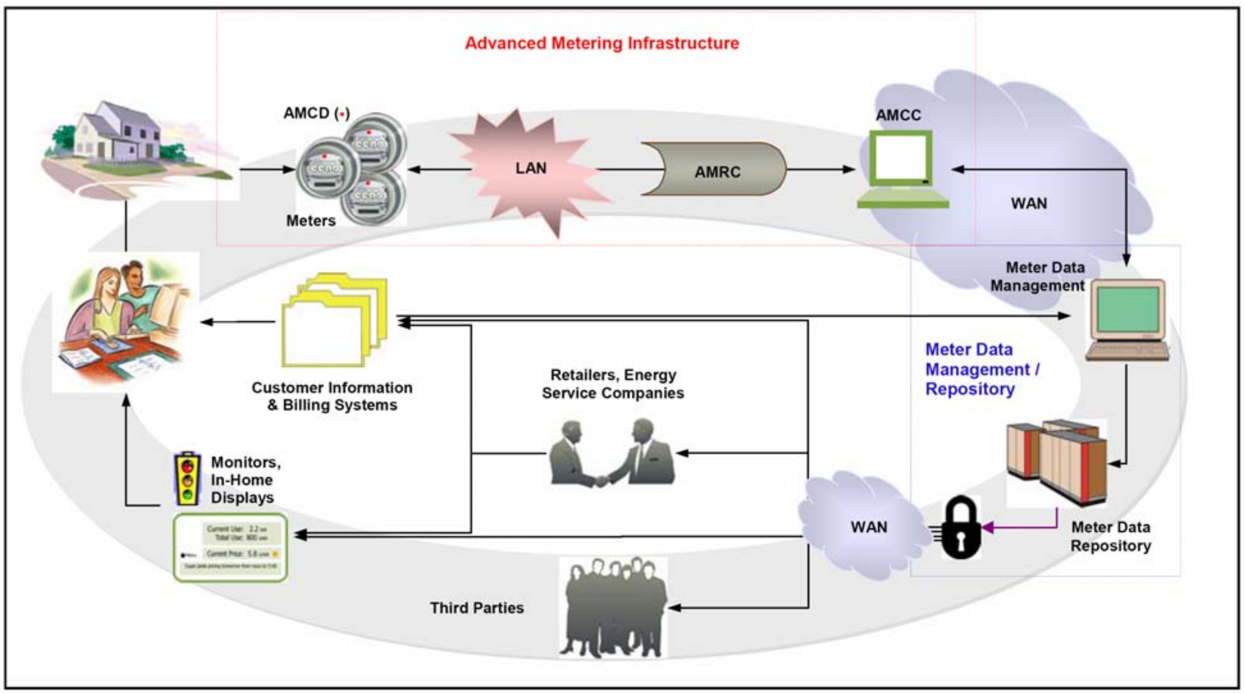
DAY OF ______________________________ 2008.
(Month)

Section 3: Project Overview

3.1 Smart Metering Infrastructure – AMI Landscape

The Advanced Metering Infrastructure (AMI) which CHEC is installing is meant to satisfy the requirements of the provincial Smart Meter Initiative (SMI), which is hoped to contribute to the creation of a conservation culture in Ontario. The metering and associated infrastructure (i.e. AMCDs, AMRCs, and AMCC) will be owned and operated by CHEC, and the centralized Meter Data Management/Repository will be owned and operated by the Independent Electricity System Operator (IESO). There are performance requirements detailing success rates for data collection from the AMI infrastructure, and time requirements within which the data must be provided to the MDM/R. Following is a diagram depicting the data flow for the Ontario Smart Meter landscape.

Figure 2: Ontario Smart Metering System Data Flow



Performance requirements for the AMI have been specified within the Ministry of Energy document entitled *Functional Specification For An Advanced Metering Infrastructure Version 2* (dated July 5, 2007, which has been provided for reference as Appendix "A"). As discussed within this document the AMI system includes the Advanced Metering Communication Devices (AMCD), the Local Area Network (LAN), Advanced Metering Regional Collector (AMRC), the AMI Wide Area Network (AMI WAN) and an Advanced Metering Control Computer (AMCC). The system will provide the infrastructure within which date and time stamped hourly meter reads are remotely collected and transmitted daily to CHEC's AMCC, and which will eventually be sent to the centralized Meter Data Repository (MDM/R) through the MDM/R Wide Area Network (MDM/R WAN).

The MDM/R functions include collecting and storing data, processing it for TOU and CPP billing, and making it accessible to consumers and to LDC's in accordance with their billing cycles. The data will also be made available to retailers, energy service companies and other interested parties in a manner that protects the privacy of consumers.

As discussed in Section 1.3 *CHEC's Approach to Smart Metering*, CHEC is currently engaged in a project to install Smart Metering in all residential locations by December 2010. Planning for the commercial and industrial component of the smart meter initiative is currently being developed and is not considered part of this proposal. However, bidders are welcome to provide comments on their offering for industrial coverage and budgetary figures should be provided separately should the vendor decide to do so.

3.2 AMI System Deployed

As stated within Section *1.3 CHEC's Approach to Smart Metering*, the following CHEC utilities will be deploying the Elster Energy Axis AMI network:

Utility	Collectors	Utility	Collectors
Centre Wellington Hydro Ltd.	6	Rideau St. Lawrence Distribution Ltd.	8
Lakeland Power Distribution Ltd.	23	Wellington North Power Inc.	5
Midland Power Utility Corporation	8	Westario Power Inc.	24
Parry Sound Power Corporation	3		

The Elster Energy Axis system is a MESH network. In this system the REX2 meters that are deployed also act as Radio "repeaters", transmitting the data from meter to meter, until the information is received by a Collector. In the Energy Axis system, A3 Alpha meters act as collectors (in addition to having the ability to act as a residential or commercial meter), which can handle data from a maximum of 2000 REX2 meters. It is not considered best practices to implement the maximum meters per collector; it has been determined that somewhere around 750 meters per collector provides optimum redundancy, and also allows for future addition of water or gas meters to the network. Appendix "B" contains CHEC service territory maps, with the anticipated AMRC locations.

The Elster EnergyAxis Metering Automation Server (MAS) is the advanced metering control computer (AMCC) component of the system for data collection and system management. The AMCC, on a predetermined/preset schedule, polls the AMRC for the metering data. This communication between the AMRC and the AMCC is via commercial WAN networks.

In the Elster EnergyAxis system, normal billing data and meter statuses are stored in the electronic registers in each meter. The A3 Alpha Meter/Collectors automatically set up their local RF networks and poll each meter six times daily. The incoming data from the individual meters is stored in the Meter/Collector. Elster's LAN technology also supports both broadcast outbound and inbound capabilities as required for real-time meter reads or remote programming. For the Elster EnergyAxis system the regional collector would be installed in a residential meter base (i.e. typically at the side of residential dwelling, approximately 1.7 meters from the ground.

The MAS server provides central system management to support both scheduled and on request meter readings. Data from the reads is output in industry-standard XML file formats for import into billing, enterprise or MDM/R applications.

The majority of data collection will occur during the Daily Read Period, and there will be situations where data collection will occur during regular business hours for the purpose of on-demand readings, troubleshooting, or network commissioning.

3.3 Deployment Territories (CI)

Maps of CHEC's individual service territories are provided within Appendix "B" to identify the areas where coverage will be required. The provided maps should aid the bidders in understanding the environment and location of CHEC's smart metering system, including the anticipated collector (i.e. WAN service points) locations.

Vendors are asked to provide a statement of recognition (i.e. compliancy) that the bidder understands CHEC's schedule for deployment and the deployment territories, and that they are providing a bid response with the intention of performing the required services for all required territories of CHEC. Given the diverse nature of the service territories, and that there are Smart Meter Deployments occurring across the province, bidders have the opportunity within this section to demonstrate (through submitted documentation/statements), how they will be able to accommodate the unique requirements of CHEC. (i.e. installation across the area according to the projected timelines).

3.4 Collector Configuration (CI)

As part of the Bidder's proposal, CHEC requires a statement of compliancy to demonstrate the understanding that as a turnkey solution provider the Bidder will be providing the required modem hardware interface to connect the AMRC (Elster A3 meter) to the WAN solution infrastructure. Vendors should confirm that the proposed hardware is certified for use with the Elster's EnergyAxis system.

There are several configurations of A3 Alpha Collectors including meter based or standalone (i.e. pole top) collectors. The collector, whether meter based or pole top can be supplied with the option of Ethernet, RS232 Output, or an internal POTS modem.

The POTS based collector has a communication rate of 2400 baud. This type of collector requires a telephone line connection. Based on preliminary data, for a regional collector (AMRC) with approximately 500 smart meters (AMCD) associated, the AMRC transmits on average approximately 55,000 bytes (0.05 MB) data daily during the daily read period. Similarly during the daily read period, the AMRC receives on average 170,000 bytes (0.17 MB) per collector to retrieve 24 hours worth of data daily.

It is recommended that WAN Solution Providers contact Elster to ensure that the solution being proposed utilizes hardware that is compatible with the Elster AMRC hardware:

Mr. Clarence Batterink
Elster Metering, Product Manager - Electricity
(905) 634-4895 x104
clarence.e.batterink@ca.elster.com
3450 Harvester Road
Burlington Ontario L7N 3W5

3.5 Scope of Work

CHEC, through this RFP, is seeking a cooperative and mutually beneficial relationship with a WAN provider which will allow CHEC to successfully fulfill their regulatory requirements for data collection. It is hoped that through this relationship, a high level of quality and service with regards to installation, security, and on-going maintenance can be acquired at a reasonably low cost. CHEC would like to explore opportunities which can potentially enhance the utility through standardized processes, improved end to end functional capabilities, and combined service offerings.

This request for proposal for AMI WAN solution addresses CHEC's requirements for smart metering in residential applications. If the bidder also provides a solution for commercial and industrial applications, the response may also address this solution distinctly segregated from the solution provided for residential application, if possible. Specifically, if the proposed solution is applicable for commercial and industrial customers with no modifications, the bidder shall identify such.

As stated previously, the AMI commercial and industrial portion of CHEC's smart meter initiative is currently under review and is not considered part of this proposal. However, bidders are welcome to provide information on their offering for these future requirements; budgetary information should be provided separately and marked clearly as "**Supplementary Information**", as detailed in Section 2.4 *Proposal Format Instructions*.

With regards to the requirements for the wirelessly connected collectors that are being installed through this second phase of AMI deployment, CHEC considers the following list of services as required to successfully satisfy the intent of this RFP:

- Project management, system design, commissioning and training
- AMI WAN system hardware and equipment
- System security (i.e. detailed security parameters to protect all information collected)
- Service levels and value added services
- Applicable costs, pricing and rates
- Provide the technical expertise required to establish communications between the AMI collector points and CHEC member utilities' back office systems
- Establish an understanding of the demarcation point
- Describe the technology roadmap for the proposed system/technology

Section 4: Bidder Company Information

4.1 Financial / Business Stability (I)

1) What is the current size (number of employees), turnover rates for last three (3) years, and location(s) of the Bidder's company?
2) Number of employees assigned to application development and support.
3) What is the current financial condition of the Bidder's company? Provide supporting documentation and annual reports for the last three years. If the company is privately held, supply sufficient information to document the company's financial status.

4.2 Experience providing same or similar products & services (I)

1) How many years has the Bidder been in business?
2) How long has the Bidder been providing WAN solutions?
3) Describe the Bidder's primary line of business and the percentage of its business derived from the sale of WAN solutions and associated services.
4) Bidders should identify and describe services they could offer CHEC as part of the Contract that would support environmentally responsible business practices.
5) Bidders are to provide data to support their safety record such as corporate safety statistics, internal safety record, WSIB rating, injury rate or injury severity. In addition, Bidders must provide documentation supporting their commitment to safety within their manufacturing facilities and design of products.

4.3 Contract Manager (I)

The vendor is asked to acknowledge the requirement to designate a contract manager, who shall have the authority to handle and resolve any technical issues, disputes or contractual issues in a timely manner. The bidder should describe the Contract Manager's experience with managing projects of a similar size and scope, including timelines, and results if applicable. Response should include the Contract Manager's and any other related team member's Curriculum Vitae (CV).

4.4 Perspectives expressed by references (I)

To ensure long-term viability and maintenance of the system, the selected Bidder must be a proven vendor in the area of application software. Bidders are requested to provide a list of at least three (3) references (contact names and phone numbers) for companies using the Bidder's proposed system to perform the same or similar application(s) as the one(s) described in this RFP for the past three (3) years.

4.5 Subcontractors (I)

Does the bidder intend to subcontract any component, service or support requested in this RFP? If so, indicate which components, services or support and identify the subcontractors. If there is an intention to utilize a subcontractor, all information requested as part of this RFP, should be provided for the subcontracting firm as well as for the prime bidder.

4.6 Minimum Competencies (CI)

First and foremost it must be stated the CHEC group's number one requirement will always remain the health and safety of its employees and customers and that proponents must comply with all applicable Provincial, Federal and Municipal acts and regulations that pertain to the work solution being proposed. The successful proponent will be:

- Responsible for knowing, understanding and ensuring that work is done in compliance with the appropriate safety legislation, EUSA rules, CHEC rules, policies, procedures and safe work practices that apply to the work.
- Responsible for identifying the job hazards, determining the solutions or barriers required to provide safe working conditions and communicating this information to all workers under their supervision.
- Responsible for ensuring all job information such as daily tailboard conference sheets, traffic plans, vehicle and equipment inspection sheets are filled out properly and returned to the office as appropriate.
- Responsible for holding documented tailboard conferences daily and ensuring appropriate worker participation in order to complete the work safely. Responsible for directing the work in a safe manner.
- Responsible for using and ensuring all crew members use and wear at all times the appropriate personal protective and safety equipment required for the work.
- Responsible for using and ensuring all crew members use the equipment, materials, and protective devices in a proper and safe manner.
- Responsible to ensure loss incidents and potential loss incidents are reported to CHEC immediately. Provide preliminary details, fill out the proper documentation and participate in the incident investigation as required.
- Responsible to report workers who do not comply with their health and safety responsibility, for corrective action by their supervisor.

Based on the nature of the work being procured through this RFP, and in accordance with the CHEC Health and Safety Policy, and depending on the WAN solution proposed, the successful Bidder will furnish the following items 21 days prior to the formal award of the contract without which is grounds for disqualification from the process:

- Acknowledgement from the Proponent that they are aware of and agree to adhere to the terms and conditions as per Section 7.
- A WSIB Clearance Certificate indicating the Proponent's firm number, account number, and that their account is in good standing.
- The Proponent further agrees to maintain their WSIB account in good standing throughout the contract period and shall produce a Clearance Certificate from WSIB from time to time during the contract on request and/or prior to final payment.
- Liability Insurance.

In addition, prior to the start of work (and throughout the duration of the work, should a CHEC utility make a request), the proponent (as is the case for any contractor working for a utility forming the CHEC), will provide:

- Field Service Personnel Health and Safety Policy and Training Program
- Proof of drivers license/insurance/police check and driver's abstract for those staff working within the CHEC territory
- EUSA electrical safety and awareness course
- Health & Safety Policy / Program (including policies/procedures for working in and around live lines, ladder safety training, MTO Book 7, fall arrest/second man/ladder rescue requirements, WHMIS MSD documentation for any hazardous materials used in the job,
- CPR/First Aid certifications
- Documentation of injury experience
- List of PPE utilized for work within CHEC
- And, any other documentation that may be deemed necessary by CHEC

Section 5: AMI WAN Solution Technical Requirements

CHEC's general expectation is that flexibility and functionality of the chosen AMI WAN Solution will enable the chosen AMI Solution to meet the requirements as outlined in the Ministry of Energy's *Functional Specification For An Advanced Metering Infrastructure Version 2* (dated July 5, 2007), included herein as Appendix "A" for reference.

As well as a response to the following subsections, the bidder's response should include (in section 5 of the response) an overview of the proposed solution. Please ensure the current functionality of your product is clearly explained. If the product is not currently able to accommodate the requirements as explained in this document, please provide a detailed development path/plan for the product. This document details the level of priority assigned to all Smart Meter technology functions.

As well as an overview of the proposed system architecture and system functionality, the documentation submitted by the bidder should include installation requirements, expected labour requirements, and any requirements for ongoing labour / operations; as this information will be of value in CHEC's SMI budgeting process.

5.1 AMI WAN Solution Overview (I)

Bidders shall provide a work/data flow diagram and comprehensive explanation demonstrating how the communications will work between the AMRC and the AMCC. Coverage maps are requested to indicate whether or not all of CHEC's service territories (as depicted in Section 3.3 *Deployment Territories*) are covered by the proposed WAN solution.

In addition, the following technical information is requested as it pertains to the proposed AMI WAN Solution:

- technical descriptions of all equipment in the proposed solution, including size, shape and weight of all proposed devices
- a description of how the equipment is mounted
- the power requirements and source of voltage for all equipment
- technical details of the equipment used to enable communication to the AMRC (i.e. Elster A3 collector) which will be equipped with a modem which will enable communications between the AMRC and the AMCC.

5.1.1 AMI WAN Solution Roadmap (I)

As per the MoE Minimum Functionality Specifications (Appendix "A"), the AMI solution chosen by CHEC will have a 15 year life. As a result, CHEC requests that bidders identify the development roadmap for the proposed WAN solution. Bidders should describe how the product will maintain backward compatibility for hardware, software, and any other required network components. In the event that hardware and/or software upgrades are required, and/or if over-the-air firmware or software upgrades are possible, the bidder should provide policies and procedures for these upgrades to demonstrate that CHEC's system uptime will be minimally affected. This is considered critical due to the performance specifications that have been specified by the Ministry of Energy.

Bidders are also requested to, if applicable, discuss possible modifications which might be necessary should CHEC deploy another AMI solution in future stages of the Smart Meter Initiative.

5.1.2 AMI WAN Solution Security (CI)

It is essential that the WAN solution have, as a minimum, end-to-end protection against cyber attack and unauthorized intrusions. Bidders shall provide comprehensive documentation describing the security measures that have been implemented to insure:

1) Data integrity
2) Data security
3) Immunity from outside (electromagnetic) interference as well as from fading and other forms of signal degeneration or attenuation,
4) Data encryption
5) MAC address filtering
6) DHCP (dynamic host configuration protocol)
7) NAT (network address translation)
8) Built-in firewall
9) User authentication (CHAP)
10) Password access (PAP)
11) Centralized password repository (global, regional, cluster or unit remote updates)
12) Bandwidth restrictions (limited data rate per unit)
13) Traffic analysis restrictions (watch for irregular traffic flows)
14) Automatic "call home" modems
15) ACL (access control lists)
16) Traffic logging

Where a security technique has been specified (i.e. DHCP) that the bidder does not apply, but where an alternative strategy has been utilized, documentation should explain both the effectiveness of their strategy and the reasons why it is felt that their solution is at least as effective as the strategy specified.

Vendors should also describe how proximity to AMCDs, topography, foliage, terrain, weather conditions, and other (neighboring utility's) AMI, etc. are expected to impact the transmission and integrity of data integrity over the fifteen (15) year operating life of the AMI will be maintained.

For bidders that are proposing the use of any off-net service providers, it is required that their security documentation include description of how security will be implemented over public domain, such as the Internet. If the proposed solution will utilize globally routable addresses, or any assigned IP prefixes are part of a global routing database, the security measure that would be implemented should be clearly explained.

Once the successful bidder has implemented their proposed WAN solution, and all necessary acceptance testing has been performed in order to show that the system is fully functional, the bidder will work with CHEC to select a mutually agreeable independent 3rd party security firm to perform an audit of the AMI WAN solution. The bidder also agrees to work with CHEC to implement any suggested improvements made by the security firm, should they be considered reasonable, and not cost prohibitive in order to eliminate (or minimize) any security breaches which may be identified by the security audit, to CHEC's satisfaction.

5.1.2.1 Breach Notification (I)

CHEC is interested in understanding the monitoring processes, as well as notification and corrective measures that are utilized by the WAN solution provider in the event that the WAN solution is breached. Additionally, bidders should discuss examples of past breaches, how they were handled, and the measures that were implemented to minimize risk of future occurrences.

5.1.2.2 Security Updates (I)

In the event that a component manufacturer releases system (i.e. security) updates for their equipment, CHEC would like to understand the WAN solution provider's policy regarding implementation and notification (i.e. timeframe) of said upgrade (i.e. what is the time from update release to update implementation?).

5.1.2.3 Unwanted Traffic (I)

Bidders should explain how the network protects against unwanted traffic (i.e. text messaging, spamming, etc). If Bidders have addressed this through Service Level Agreements in the past with other customers, CHEC is interested in any information that can be provided in this regard.

5.1.3 AMI WAN Scalability (I)

Bidders should demonstrate through documentation that the system is capable of at least the 76 WAN points being procured through this RFP, that the system has been tested to higher volumes, and also describe larger deployments and other business endeavours which demonstrate scalability. Depending on future growth, or the addition of other commodities to the AMI (i.e. water, gas), there is the potential for more endpoints to be deployed.

5.1.3.1 Bandwidth (I)

It is acknowledged that the bandwidth required for Smart Metering applications may, at this time, be considered minimal (see Section 3.4 *Collector Configuration (CI)* for estimation of current bandwidth usage). However, CHEC has intentions of exploring the possibilities of incrementally expanding use of the Smart Metering network to include other functions such as Smart Grid (i.e. transmission/distribution monitoring equipment) as well as security camera functions, VoIP, multi-commodity data collection, etc. Bidders are asked to provide details around the amount of bandwidth being proposed with the Smart Metering solution, as well as the flexibility (and incremental costs associated) to expand the solution should that be required in order to accommodate additional functions.

5.2 AMI WAN Coverage (CI)

It is CHEC's intention to utilize one service provider for AMI WAN coverage. It is therefore expected that the bidder will be capable of ubiquitous coverage across CHEC service areas, as described in Section 3.3 *Deployment Territories*. If the bidder cannot support all the use cases on their network, and will utilize the capacity of another carrier in order to provide service across all of CHEC's territories, it is requested that the bidder identify and describe any off-net network elements, and the level of control over these carrier in the event of a critical service interruption. The Service Level Agreements and assurances between the bidder and the off-net service provider should be discussed.

5.2.1 Quality Assurance (I)

Bidders should describe how they will measure and track their performance as a service provider. Samples of any discussed reporting functions should be included in the response. Describe any ongoing maintenance service offerings relevant to the proposed solution, and any additional costs which might be required as part of the maintenance agreement.

Explanation should include how the bidder would keep CHEC informed of scheduled downtime/maintenance, keeping in mind the importance of the midnight to 5 am period of time which is so critical in allowing CHEC to meet the regulated requirements for AMI performance (as found in Appendix "A").

5.2.1.1 Claims Administration (CI)

As part of providing exemplary customer service, the bidder is expected to handle customer complaints that are related to their services and provide customer assistance to resolve issues resulting from negligence to the satisfaction of the utility, ensuring all claims are reported. Claims not resolved after 10 days should be reported to the utility for resolution.

5.2.2 Disaster Recovery (I)

The Proponent shall provide comprehensive information around disaster recovery; explanation should include disaster recovery for equipment in the field, equipment at the service provider's facility, and any equipment which is intended to reside at any of CHEC's facilities. Bidders should explain the capacity within the proposed solution for remote fault resolution due to device malfunction.

Included in the description of technical services available to best ensure the AMI WAN solution maintains an acceptable level of performance (as detailed in Appendix "A"), the bidder is asked to discuss how proactive, real time WAN network surveillance, alarming and trouble ticketing would be accomplished. If there are any network elements provided by the Vendor that cannot or will not be monitored remotely, this should be clearly explained. If off-net facilities are to be used in the proposed system, describe the off-net provider's network monitoring capability.

5.2.2.1 Equipment Configuration (I)

It is critical that CHEC understand the configuration of the equipment (hardware settings, software settings, all known optionable user configuration parameters) so that in the event that a WAN related issue is encountered, requiring equipment restart, the necessity of a truck roll is minimized. It would be CHEC's preference that in the vast majority of instances, equipment could be remotely restarted and reset.

5.2.2.2 Surge Transient Protection (I)

Transient Voltage Surge Suppressors protect against transient voltage spikes which can be caused by in building events such as switching of lighting and the starting and stopping of motors, electrical fault conditions (equipment failure which passes high currents to ground or from phase to phase, power failure and the subsequent return of power, or external causes such as lightning strikes that hit the electrical system in your nearby geographical area, and lightning strikes that induce transients through radiation of electric-magnetic fields without hitting the electrical system. Transient surges may cause serious damage to communication interfaces inside a building.

Due to the many ways a transient surge may be created, a single surge suppression layer applied to incoming lines may not be appropriate to completely shield the internal lines and equipment from transient voltages.

Bidders are asked to provide details around the layering of surge protection devices/solutions that are provided with the proposed solution.

5.2.3 AMI WAN Service Level Agreements (CI)

Bidders should state their acceptance with CHEC's Service Level Agreement requirements for WAN coverage, as outlined below:

- 99.99% uptime during the Midnight through 5:00 am time period.
- 98% uptime during the remaining daily time period (i.e. 5:00:01 am through 11:59:59 pm)
- Percent of daily (register) readings captured: 98% in 24 hours

The AMI system has been designed (with appropriate infrastructure) to accommodate the Ministry of Energy specified performance requirements. It is imperative that the proposed WAN solution not impede the AMI system's ability to meet these performance requirements. AMI WAN solution providers are requested to acknowledge that the proposed AMI WAN solution will facilitate the achievement of these statistics, rather than impede success, and that the pricing provided within the Pricing and Compliancy spreadsheet has been provided with these Service Level Agreements in mind (Pricing option tabs have been provided in the event that a bidder would like to provide pricing for a solution they might consider the most "cost-effective", but it is imperative that the pricing that has been entered in tab 1 reflect the costs associated with a system which will allow the above stated Service Levels to be met).

In addition, AMI WAN providers are asked to provide examples of Service Level Agreements that have been constructed with clients in the past (who have like data transfer requirements).

5.2.3.1 Redundancy / Auto Failover (I)

Bidders are requested to provide detail regarding the coverage redundancy and fail over planning (i.e state tower:AMRC ratio) that is inherent to the proposed solution which will ensure the performance levels that are expressed in Section 5.2.3.1 *AMI WAN Service Level Agreements* can be achieved.

In addition to redundancy planning, CHEC would like to understand the immediate and near term maintenance requirements for the system.

5.2.3.2 Remote Monitoring, Logging & Alerting (I)

If the bidder's proposed WAN solution includes remote monitoring functionality such that CHEC is able to troubleshoot encountered problems to alleviate potential service calls, resulting in increased system uptime, bidders are asked to provide details.

5.2.3.3 System Updates (I)

With respect to the Service Level Agreements required in Section 5.2.3.1 *AMI WAN Service Level Agreements* CHEC acknowledges that the WAN solution provider will need to upgrade system components. CHEC is interested in the WAN solution provider's capabilities to do this remotely, the anticipated frequency with which this will occur, and the actual impact to system uptime.

5.2.4 AMI WAN Solution Warranty (I)

Bidder should provide documentation and field testing results attesting to the expected life of the proposed equipment. For equipment that will be used outdoors, the durability and ruggedness should be discussed as well as the Mean Time Between Failure and Mean Time to Repair for all proposed equipment.

The Bidder shall provide information detailing the warranties that are provided with the proposed AMI WAN solution. Should the Bidder's warranty statement be greater than one page in length, please include a summary highlighting the following items:

1) Term: term of warranty for all associated hardware and software, and possible pro-rated scenarios,
2) Fault: cost coverage and obligations depending on whether deficiency is attributed to manufacture / workmanship, off-net service provider, or some fault of CHEC,
3) Labour: detail whether labour costs covered by the WAN Solution Provider if a fault is found in the product after the solution has been deployed.

The Bidder's warranty information should include the procedure which would be required by CHEC when defects in materials and/or workmanship are found. Bidder's Response should include descriptions of the Bidder's obligations, as well as the obligations of CHEC.

CHEC's assumption (with regards to warranty) is that the proposed AMI WAN solution infrastructure will function as an integrated system, as represented in the Bidder's proposal document. If this assumption (with regards to warranties) is incorrect, the Bidder's documentation should include documentation regarding potential communication problems and their impact to the system warranty.

5.3 Project Management (I)

It is preferred that the proposed WAN solution be flexible enough that the schedule for Smart Meter deployment is not impeded by the WAN solution requirements. As CHEC prepares to deploy meters within an area, a list of possible collector sites would be provided to the successful WAN solution provider with the intention (ideally) that the WAN solution would be installed in conjunction with the meters.

Bidders are asked to propose a project plan complete with milestones and deliverables. It is CHEC's expectations that this project will be managed by the Contract Manager referenced in Section 4.3 *Contract Manager* of the bidder's response.

The project plan should include the process for end-to-end testing, and the procedure to install and commission the AMI WAN solution with the AMI system. Tasks that are to be completed by CHEC should be clearly identified along with the required skill sets for CHEC's team members and any training that may be required for CHEC's staff (including field service representatives, management and IT personnel). Bidders should provide training requirements (description of training required, time required for training, training format), in order to bring applicable CHEC Staff to a level of proficiency which will allow basic troubleshooting to identify possible communication equipment failure and the area of responsibility.

5.4 AMI WAN Certifications (I)

Bidders are to identify all applicable Health Canada and Industry Canada requirements and CSA certifications that pertain to the proposed solution. Information should include all manufacturing approvals that might be required. Response to this section should include safety standards for the manufacture of equipment as well as safety standards that must be met for the installation of the proposed solution.

Documentation demonstrating the bidder's license to operate on the proposed frequencies should be included.

Within this section, Bidders are also requested to describe any precautions that are taken to reduce and/or eliminate the possibility of tampering with the proposed solution.

5.5 AMI WAN Solution Installation (I)

Bidders should provide a comprehensive description pertaining to the installation of the proposed equipment. Within their explanation regarding the installation of the proposed AMI WAN solution, bidders should include the following:

i. The environmental tolerances of all proposed equipment. Bidders may choose to provide technical specifications for the proposed equipment, however, included within this section should be an explanation of their operating tolerances with regards to temperature and humidity, and whether the equipment is intended for installation indoors or is expected to be mounted outdoors, and where (i.e. pole top, bidder owned antennae, etc)
ii. As it pertains to section i above, explain the possible impact to the proposed equipment if it were installed indoors, or within a meter cabinet.
iii. Explain, in detail, how the system configures itself upon installation, as well as recovery from outage events (i.e. power outage, network outage, modem resets, modem hangups, etc).
iv. Tools that are required to ensure there is coverage at the installation site
v. Routine operation and required maintenance of the installed system
vi. Troubleshooting, diagnosis and repair of the installed system
vii. Training on test equipment needed to maintain the system

The project plan should include the process for end-to-end testing, and the procedure to install and commission the AMI WAN solution with the AMI system. Tasks that are to be completed by CHEC should be clearly identified along with the required skill sets for CHEC team members and any training that may be required for CHEC staff (including field service representatives, management and IT personnel). Bidders should provide training requirements (description of training required, time required for training, training format), in order to bring applicable CHEC Staff to a level of proficiency which will allow basic troubleshooting to identify possible communication equipment failure and the area of responsibility.

5.5.1 System Support (I)

Bidder shall describe the process by which the originally furnished hardware/software is maintained and upgraded. Included in this description should be information pertaining to any 3rd party software licenses, and the associated costs, and any recurring costs associated with maintenance (software or otherwise) or upgrades. Bidders shall describe any one-time or recurring licenses, keys, restrictions of use, or limitations (and all associated costs) that may in any way restrict CHEC's full and open use of the proposed solution. **If restrictions are not described, Bidder represents that there are no such restrictions, or requirements.**

Bidder shall provide an hourly rate for trouble service calls which may be issued by CHEC.

5.6 Value Added Services (I)

CHEC currently utilizes cellular technology devices for field staff including Blackberry devices capable of email functions.

CHEC is also interested in Workforce Management (WFM) systems and may choose to deploy this in their service territories in the future. The handheld devices would be utilized by field staff and will be capable of wireless integration with CHEC back office systems.

CHEC would like to explore opportunities to reduce cost and/or increase efficiencies. If the bidder is able to provide cost savings opportunities by way of device bundling, pooling of minutes, or otherwise, information should be provided.

Section 6: Price Submission Requirements

Please note that all documentation must reflect current capabilities. Any future capabilities must be stated as such, and a development schedule outlined.

Describe in detail the pricing for the systems proposed. Detail any assumptions made in the proposed solution and pricing. All of this information should be included within the Pricing and Compliancy Spreadsheet.

In addition to the minimum functionality required by the Ministry of Energy, CHEC is interested in the ability to support load control devices, and multi-utility meters, as this capability is in line with both the intent of the Ministry of Energy, and the service goals of CHEC. Therefore, in addition to the current data collection requirements outlined in Section 3.4 *Collector Configuration (CI)*, CHEC expects to increase non-scheduled data communications to the network. These anticipated communications would in all likelihood include only specific areas and low volumes of meters during any one communication.

6.1 Pricing Submission

The Pricing and Compliancy Spreadsheets allows for the Bidder to provide two options for the proposed WAN Infrastructure:

1) Within the tab labelled "Pricing_Option1" Bidders are required to submit pricing (Capital and 15 year Operating costs) for the proposed WAN Solution (which has been designed with the redundancy required to meet the Service Level Agreements outlined in Section 5.2.3 *AMI WAN Service Level Agreements* and all stated data requirements).
2) Within the tab labelled "Pricing_Option2" Bidders are permitted to submit pricing (Capital and 15 year Operating costs) for the proposed WAN solution; in the event that the bidder feels Option 1 is NOT the most cost effective solution. Pricing_Option2 is where the Bidder is able to provide suggestions with regards to the design of the solution which will allow for more "cost effective" service options. If required, the bidder may add tabs to provide further options.

NOTE: As per Section 2.4 Proposal Format Instructions, the PRICE OFFER should be submitted in a separate envelope which has been clearly marked "PRICE OFFER".

6.2 Incremental Costs

In addition to the Pricing Options described in Section 6.1 *Pricing and Compliancy Submission*, Bidder's are required to submit the incremental cost for any functionality that is discussed in their proposal which does not come standard with their product. If an incremental cost is not provided, it is CHEC's understanding that the functionality comes standard with the product being proposed.

Section 7: Contract Terms and Conditions

7.1 Commencement of Contract Time

The successful Vendor shall acknowledge acceptance of the Purchase Order from CHEC within 10 days of its issue.

The Contract Time shall commence to run on the effective date indicated in the Purchase Order. Vendor shall start to perform the Work on the date when the Contract Time commences.

7.2 Vendor Claims

All claims of the Vendor and all questions relating to the interpretation of the Contract, including all questions as to the acceptable fulfillment of the Contract on the part of the Vendor and all questions as to compensation, shall be submitted in writing to CHEC Project Manager for determination.

All such determinations and other instructions of CHEC will be final unless the Bidder shall file with CHEC a written protest, stating clearly, and in detail the basis thereof, within fifteen (15) calendar days after CHEC notifies the Bidder of any such determination or instruction. CHEC will issue a decision upon each such protest within fifteen (15) calendar days and its decision will be final. Work will not be undertaken until a written final decision is rendered.

7.3 Changes in the Work

CHEC, without invalidating the Contract, may direct the Vendor to perform extra work or make changes in the work, provided that all changes or additions form an inseparable part of the work contracted for. Vendor shall make such changes or additions only after receipt of written instructions to do so from CHEC. If such changes or additions cause an increase or decrease in the cost of the Contract, or in the time required to complete the Contract, an equitable adjustment shall be made and the Contract shall be modified accordingly by a Change Order in writing.

When a change is ordered, a change order shall be executed by CHEC and the Vendor before any change order work is performed. Any increase or decrease in the contract price and the time required for the completion of the contract work due to a change order shall be specifically set out in the change order. All terms and conditions contained in the Contract Documents shall be applicable to change order work. The amount of any increase or decrease shall be added to or subtracted from the contract price as appropriate.

7.4 Delays & Extension of Time

If the Vendor is delayed at any time in the progress of the work by any act or neglect of CHEC, or any cause beyond the Vendor's reasonable control, he shall file with CHEC a notification that an extension of the Contract period is required.

CHEC Project Manager shall review said notice and to the extent that the Vendor can reasonably demonstrate to CHEC Project Manager that it shall be delayed in its fulfillment of these terms and conditions and other obligations of this transaction due to a cause beyond its control, a reasonable extension period shall be granted.

7.5 Termination of Right to Proceed

CHEC may, in writing, terminate this Contract in whole or in part at any time, either for CHEC's convenience or for the default of the Vendor. Upon such termination, all data, plans, specifications, reports, estimates, summaries, completed work and work in process, and such other information and materials as may have been accumulated by the

Vendor in performing this Contract shall, in the manner and to the extent determined by CHEC, become the property of CHEC. If the termination is for the convenience of CHEC, an equitable adjustment for the Vendor's direct costs and profit for work actually performed shall be made by mutual agreement between the Vendor and CHEC. No amount shall be allowed for anticipated profit on unperformed services.

Default occurs if the Vendor (1) abandons the Work called for hereunder, (2) files a voluntary petition in bankruptcy or fails to obtain dismissal of an involuntary petition in bankruptcy within sixty (60) days after the filing thereof or has a Receiver/Trustee appointed, (3) becomes insolvent, (4) assigns this Contract or sublets any part of the Work hereunder without prior written permission of CHEC, (5) repudiates the Contract, (6) allows liens to be filed against property of CHEC, (7) disregards laws, ordinances, rules and regulations related to the Contract and the Work or disregards instructions of CHEC. Any expense incurred because of cost of completion by CHEC is chargeable to and shall be paid by the Vendor. The total liability to the Vendor shall be limited to the Contract value less the value of any equipment, material or completed services retained by CHEC.

7.6 Right to Operate Unsatisfactory Equipment

If the operation or use of the materials or equipment after delivery and/or installation does not reasonably comply with the technical requirements set out in the Contract Documents to CHEC, CHEC shall have the right to operate and use such materials or equipment until such deficiency can be reasonably corrected provided that the period of such operation or use pending correction shall not impede or delay the ability of the Vendor to perform corrections. Such operation and use shall not constitute an acceptance of any part of the work, nor shall it relieve Vendor of any requirements of the Contract, nor shall it act as a waiver by CHEC of any requirement of the Contract.

7.7 Work Protection

Work protection from electrical hazards, where required, shall be applied for prior to beginning work and shall be consistent with the Electric & Utilities Safety Association's Protection Code, and upon review and acceptance by Bidder, utility requirements. Protections shall be surrendered at the end of each working day. In general, daily requests shall be available during utility normal working hours only.

Signalling and traffic protection shall be done according to the Occupational Health and Safety Act, the Highway Traffic Act, and utility requirements.

Only competent personnel shall work within the ten feet limit of approach for apparatus energized over 750 volts. The utility Manager of Engineering and Maintenance shall have the sole discretion to determine such competence, but Bidder will assume full liability in respect of any such personnel, even if approved of by the utility. Equipment, tools, and protective clothing shall be in accordance with the Electric Utilities Safety Association, the Occupational Health and Safety Act, and other authorities having jurisdiction.

7.8 Site Housekeeping

During the performance of the work, Bidder shall ensure that the work site is kept as neat and orderly as possible, in keeping with the nature of the work in progress. When work is interrupted for any length of time, or at the completion of the work, all waste material shall be removed and tools, equipment and surplus material shall be removed or stored or secured in a neat and safe fashion.

7.9 Casualty Insurance

Before commencing work under this contract the Vendor at his own expense shall submit Certificates of Insurance, providing evidence acceptable to CHEC indicating that the Vendor has obtained and will maintain insurance for the duration of the contract. The following requirements apply to all Certificates of Insurance:

i. The insurance shall be written by an insurer acceptable to CHEC,

ii. The insurance shall be primary to any coverage carried by CHEC.

iii. The Vendor further agrees to provide CHEC with an executed Certificate of Insurance before commencement of work, and with written copies of the insurance policies at any time upon the written request of CHEC.

iv. The Certificate of Insurance shall be an original copy signed by an authorized representative of the insurance carrier(s). (Note – faxed copies may be accepted initially to be followed up by originals in a reasonable length of time.)

v. The Certificate of Insurance shall provide that no less than 30 days advance notice will be given in writing to CHEC prior to cancellation, termination or alteration of the insurance coverage. CHEC shall be named as an additional insured on each General Liability Insurance Policy and any Excess Liability Policy or Umbrella Policy used to meet the required general liability limits.

The types of coverage and minimum limits are as follows:

1) GENERAL LIABILITY*
   a) $5,000,000 each occurrence
   b) $6,000,000 general aggregate
2) AUTOMOBILE LIABILITY*
   a) Bodily injury $5,000,000 per person
   b) $5,000,000 per accident
   c) Property damage $500,000 or
   d) Combined Single Limit $1,000,000

** A blanket, umbrella, and/or excess liability policy(s) may be utilized to increase limits to the desired level(s).*

7.10 Subcontractors

CHEC reserves the right to refuse to permit any person or organization (subcontractor) to participate in the work covered by this Contract, such refusal shall not be unreasonably imposed. No subcontract shall relieve the Vendor of any liabilities or obligations under the Contract, and the Vendor agrees that Vendor is fully responsible to CHEC for the acts and omissions of Vendor's subcontractors and of persons employed by them. Vendor shall require every subcontractor to comply with the provisions of the Contract.

7.11 Payment

Payment shall be made based upon completion of the performance milestones itemized below.
Vendor shall submit to CHEC a request for payment for each milestone that has been met. Payment for each milestone shall also be contingent on successful completion of the preceding milestones.

1) Fifteen percent (15%) of the contract price will be paid after the successful Acceptance Test, which requires delivery and integration of the system head-end.
2) Twenty five percent (25%) of the contract price will be paid after delivery of 35% of the communication infrastructure and 35% of the new meters and other customer premises equipment.
3) Twenty percent (20%) of the contract price will be paid upon successful installation, operation and route Acceptance of the equipment described in (2) above and delivery of an additional 30% all equipment on CHEC's system.
4) Twenty percent (20%) of the contract price will be paid upon successful installation, operation and route Acceptance of the equipment described in (3) above and delivery of all remaining system elements.
5) Twenty percent (20%) upon completion of system installation, Acceptance of all routes, and delivery of all documentation, judged by CHEC to be acceptable, in any event not longer than 90 days after complete installation.

CHEC will make payment within thirty (30) days of receipt of a request for payment, if above conditions are met.

When the Vendor has completed all work in accord with the terms of the Contract Documents, the Vendor shall submit to CHEC a request for final payment. The request for final payment shall constitute a waiver of all claims by the Vendor except for claims specifically listed in the request.

Vendor's submission of its request for final payment shall constitute its warrant that the Vendor has to the best of its knowledge fully completed all work included in the Contract and has fully paid for labour, materials, equipment, services, taxes and all other costs and expenses resulting from this Contract.

7.12 Acceptance

These terms and conditions become binding when accepted by the Vendor either by acceptance of the contract or commencement of performance. No modification hereof and no condition stated by Vendor in accepting or acknowledging this order, which is in conflict or inconsistent with, or in addition to the terms and conditions set forth herein, shall be binding upon CHEC unless accepted in writing.

7.13 Shipments

Vendor shall mail Bill of Lading and Shipping Memo to destination, and CHEC's Project Manager.

Vendor shall notify CHEC Project Manager promptly if unable to make shipment. Shipments shall be made to multiple destinations in CHEC's service territories for logistical convenience. Such shipment instructions will be stated in the purchase contract that will be developed between the selected Vendor and CHEC.

7.14 Prices

Vendor agrees that prices are firm unless otherwise noted, and Vendor warrants that said prices do not exceed the prices allowed by any applicable Federal, Provincial or Local regulation.

7.15 Compliance with Laws

Vendor warrants that in performing work under this order Vendor will comply with all applicable laws, rules and regulations of governmental authorities and agrees to indemnify and save CHEC harmless from and against any and all liabilities, claims, costs, losses, expenses, and judgments arising from or based on any actual or asserted violation by the Vendor of any such applicable laws, rules and regulations.

7.16 Patents

Vendor agrees to protect and save harmless CHEC from all costs, expenses or damages, arising out of any infringement of claim or infringement or Patents in CHEC's use of material or equipment furnished pursuant to this order.

7.17 Assignment

Vendor agrees that neither this order nor any interest herein shall be assigned or transferred by Vendor except with the prior written approval of CHEC.

7.18 Substitution

No substitution will be permitted under this order except on specific written authority of CHEC's Project Manager.

Craig
Keen
Despatie
Markell
LLP

INDEPENDENT AUDITORS' REPORT

To the Ontario Energy Board (OEB)

At the request of Rideau St. Lawrence Distribution Inc., we have audited the total capital expenses and the total operation, maintenance and administration expenses for smart meter costs as at August 31, 2011 which is presented in Exhibit 1 ("financial information"). These costs do not include any payroll or overhead costs of the corporation. This financial information has been prepared in accordance with the accounting guidelines established by the OEB.

Management's Responsibility for the Financial Statements

Management is responsible for the preparation and fair presentation of these financial information in accordance with the accounting guidelines established by the OEB, and for such internal control as management determines is necessary to enable the preparation of financial information that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibility

Our responsibility is to express an opinion on the financial information based on our audit. We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial information. The procedures selected depend on the auditors' judgment, including the assessment of the risks of material misstatement of the financial information, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the financial information in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the financial information.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the financial information present fairly, in all material respects, the total capital expenses and the total operation, maintenance and administration expenses for smart meters costs as at August 31, 2011 in accordance with the accounting guidelines established by the OEB.

Basis of Accounting and Restriction on Distribution

Without modifying our opinion, we draw attention that the financial information has been prepared in accordance with the accounting guidelines established by the OEB. As a result, the financial information may not be suitable for another purpose. Our report is intended solely for Rideau St. Lawrence Distribution Inc. and the OEB and should not be distributed to parties other then Rideau St. Lawrence Distribution Inc. or the OEB.

Craig Keen Despatie Markell LLP

Craig Keen Despatie Markell LLP

CHARTERED ACCOUNTANTS
Licensed Public Accountants

October 18, 2011
Cornwall, Ontario

Robert W. Craig
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Brian D. Keen
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Rideau St. Lawrence Distribution Inc.
Summary of Smart Meter Costs
As at August 31, 2011
Exhibit 1

Smart Meter Expenses	Line Item	Dec 31/10	2011	Aug 31/11
Smart meters	1.1.1	$ 694,869.30	$ 46,139.99	$ 741,009.29
Installation costs	1.1.2	113,987.26	21,177.00	135,164.26
Collectors and installation	1.2.1	50,889.86	0.00	50,889.86
Computer hardware	1.3.1	13,757.04	1,810.10	15,567.14
Computer software	1.3.2	65,873.14	16,500.00	82,373.14
Wide area network	1.4.1	33,753.59	0.00	33,753.59
Professional fees	1.5.3	81,406.75	22,080.76	103,487.51
Integration	1.5.4	17,427.40	0.00	17,427.40
Program management	1.5.5	71,000.91	0.00	71,000.91
Other advanced metering infrastructure capital	1.5.6	-186.30	-133.20	-319.50
		1,142,778.95	**107,574.65**	**1,250,353.60**
Local area network maintenance	2.2.1	29.94	36.86	66.80
Advanced metering control computer software	2.3.2	10,709.20	28,539.18	39,248.38
Wide area network	2.4.1	3,020.78	1,722.48	4,743.26
Customer communication	2.5.2	2,324.60	0.00	2,324.60
Change management care	2.5.4	0.00	990.00	990.00
Safety and maintenance		2,591.84	781.79	3,373.63
Other	2.5.6	2,167.60	-2,167.60	0.00
		20,843.96	**29,902.71**	**50,746.67**
Meter data management and repository		**0.00**	**23,315.83**	**23,315.83**
Depreciation expense		**51,735.00**	**4,950.00**	**56,685.00**
Interest improvement		**1,040.86**	**0.00**	**1,040.86**
Total costs		**1,216,398.77**	**165,743.19**	**1,382,141.96**
Accumulated depreciation		**-51,735.00**	**-4,950.00**	**-56,685.00**
Net book value		**1,164,663.77**	**160,793.19**	**1,325,456.96**
Smart Meter Revenue				
Residential		173,965.86	86,719.86	260,685.72
Commercial		27,155.05	13,498.90	40,653.95
Industrial		2,309.55	1,180.89	3,490.44
Unbilled		14,065.00	0.00	14,065.00
Sub total - Revenue		**217,495.46**	**101,399.65**	**318,895.11**
Net smart meter capital cost		**947,168.31**	**59,393.54**	**1,006,561.85**
Stranded Meters				
Cost		295,771.51	0.00	295,771.51
Accumulated amortization		-115,329.84	0.00	-115,329.84
Net book value		**180,441.67**	**0.00**	**180,441.67**
TOTAL COSTS		**$ 1,127,609.98**	**$ 59,393.54**	**$ 1,187,003.52**

Note: There is no Rideau St. Lawrence Distribution Inc.'s payroll or overhead costs included in the amounts presented on this schedule.